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ANALYZING MULTIPLE-PRODUCT POWER MARKETS - INTRODUCTION AND SUMMARY

Restructuring of the electric power industry has unbundled the energy generation, transmission, distribution, and reliability services previously supplied by vertically integrated utilities. Federal Energy Regulatory Commission (FERC) Order Nos. 888 and 889 enable entities that can supply the components of reliable electrical service to compete to provide these services in wholesale power markets. In December 1999, following the initial creation of several Independent System Operators (ISOs), FERC issued Order No. 2000, which requires that owners of transmission systems that wheel wholesale power form or join Regional Transmission Organizations.

The unbundling of the energy industry has divided the old integrated utilities into a complex system of new and often independent entities, including

- operators of generating facilities,
- purchasers of wholesale electricity,
- non-profit or for-profit operators of transmission grids, and
- traders in the various energy, transmission, and capacity products offered by the restructured industry.

In this decentralized decision-making environment, the explicit planning and coordination of the integrated utility is replaced, to a greater or lesser extent, by the investment and operating decisions of firms that respond to market signals in their efforts to provide maximum return for shareholders. The interpretation of price signals becomes a primary business task of the new market participants. This task is more complex than the unit-commitment, transmission planning, and generation growth problems of the old utility: to the difficulties associated with anticipating uncertain future events are added the problems of anticipating the behavior of the other players in the industry.

Objectives

Modeling tools that take into account both the complexities of the multiple products of the unbundled industry and the independent reactions of the many participants in the new industry will assist in efforts to plan for the future and manage in the present. This report draws on experience gained by observing and modeling the different regional markets and from supporting the new market participants in their daily transactions and periodic asset valuation and development decisions. The purpose of the report is to describe the principal features of the new and evolving regional markets for energy and ancillary services; to describe how prices are formed and interact in these new markets, and thus set the parameters for realistic modeling of both energy and ancillary services prices and their volatilities. The report also illustrates the application of novel analytical techniques to specific problems of plant operation, RTO and transmission system functions, transaction optimization, risk management, and asset valuation and development.

The information outlines a pricing framework that will help in understanding the building blocks of existing regional and nascent markets. It will also provide guidance to understanding, on EPRI's behalf, what kinds of R&D are feasible and necessary to meet new needs for market analysis and profitable generation management. The aim in this report is not to suggest what structure or particular regulatory regimes the various regional markets should adopt, but rather to assess the consequences and implications of these markets as they now exist and are evolving.

Approach

The core of this work on multiple-product markets in the restructured power industry is a series of simulations of generator behavior and market outcomes, in which generators respond rationally to expectations that are consistent with observed market outcomes. The report provides examples of the Rational Expectations Equilibrium Pricing ("REEP") methodology, which imposes basic conditions of internal consistency on modeling efforts. It integrates and builds on findings presented in a series of recent and forthcoming published articles that introduce different aspects and applications of REEP methodology. The applications of REEP methodology are performed in the context of the UPLAN power-market modeling suite, which includes detailed databases of the existing and announced stock of generating capacity, of loads around the country, and of the transmission network tying loads to generating resources. This finely-grained modeling environment permits simulation of the decisions and actions of individual generators, while requiring consistency with the physical limitations of the embedded AC-Optimum Power Flow model of the transmission grid.

Extensions of the basic model allow simulation of markets for unbundled reserves and other ancillary services in which the cost of providing reserves is specified as the alternative cost (i.e., the opportunity cost) of the profits that might otherwise have been earned from the delivery of energy or other services. The detailed nature of the underlying databases (particularly those describing loads and those describing generators) allows Monte Carlo analysis of volatility and assessments of system reliability. Such quantification can be applied for both an individual firm's evaluation of investments and the control-area or RTO operator's analysis of its transmission adequacy, congestion management, grid expansion and tariff planning functions.

Report Organization

The report is organized as follows. First, Section 2 describes the major existing market designs, ranging from the tight-pool arrangements of the East Coast, through the formal product auctions of the California ISO, to the operations of implicit markets by "for-profit" Transcos located elsewhere. This section emphasizes the interaction of multiple products from the perspective of market participants. Despite the differences in regional market structures, the existence of competitive markets in energy and ancillary services leads to commonalities of price behavior, implications for transactions optimization, and impacts on generation asset profitability. Section 3 describes fundamental linkages between energy and ancillary services markets that underlie realistic evaluations of prices and asset values. Section 4 explains the Rational Expectations Equilibrium Pricing (REEP) methodology, a concept that captures the essential price dynamics in these regional markets. This section also compares how different approaches to modeling the new industry may yield different results and defines those features that must be properly accounted for in realistic analyses of the new business circumstances. Section 5 describes several examples that illustrate applications of these assessment techniques to solving real problems in transactions optimization and asset valuation, while Section 6 applies the model to the problems facing a reliability or transmission grid manager, such as an independent system operator (ISO) or regional transmission organization (RTO).

Principal Observations

A major characteristic of the new energy and ancillary services markets is their interrelationship and connectedness. It is not meaningful to speak of ancillary services prices apart from energy prices. For this reason, we adopt the term "multiple product prices" to emphasize the interrelationships. However, we do not imply that these prices interact in a uniform manner or yield a uniform statistical relationship to one another, which they do not. The principal findings and observations regarding these multi-product markets are as follows:

- **The interpretation of diverse price signals is a primary business task of the participants in restructured energy markets.** Whether in the day-to-day operations of individual generating facilities, the development of risk-management strategies, or in longer-run decisions to invest in new facilities or sell or retire an existing plant, the actual or potential owners of generating facilities must project and interpret the prices of spot and forward energy, capacity for operating reserves and other ancillary services, the costs of long-distance transmission, and so forth.
- **The relevant prices in the restructured power industry are determined simultaneously through the interaction of many different participants in several distinct, although interdependent, markets**. The short history of the restructured energy industry makes it difficult to apply statistical estimation to obtain future price forecasts. However, the strong and well-understood structural relationships that define energy production and transmission allow the construction of structural models that are capable of useful simulation-based price forecasts and other analyses.
- **Price volatility is an important element of the restructured energy industry.** This is partly a consequence of the requirement for instantaneous balance between loads and resources, combined with the very high cost of maintaining inventories. Various market drivers can cause physical and financial shocks. They include factors such as changes in weather, unexpected loss of generation and

transmission facilities, and changes in fuel prices. Modeling this volatility is essential to both risk management and to decisions to invest in new capacity.

- **Taking full account of the various prices and the volatility of those prices is essential to decision-making in the restructured energy industry.** Several case studies are illustrated here, involving asset valuation in the presence of volatility and ancillary services, the operation of generation in markets for energy and ancillary services, and the development of risk management strategies. These examples demonstrate both the costs of neglecting the complexities of the new marketplace and the ability of REEP modeling tools to meet these challenges.
- **REEP methodology is useful to the reliability manager, as well as to the manager of generation assets.** Reliability managers, such as independent system operators or regional transmission organizations, must evaluate the likelihood of loss-of-load events. These events are, in turn, the result of the actions of independent agents, such as managers of generation, and the varying loads that are served through the grid operated by the reliability or RTO manager. The reliability manager must forecast, explicitly or implicitly, the behavior of these agents, as well as the likelihood and impact of various contingent events. REEP methodology, including structural volatility modeling, permits a consistent identification of impending challenges to system reliability (such as generation and/or transmission insufficiency), and projects the likelihood of future prices and resulting levels of reliability.

Report Overview

In the restructured U.S. electric power industry the need for system operators to maintain system reliability and the ability of generators to respond to changing electric loads has created markets for different electricity products. These multiple products are differentiated by their energy delivery requirements. They are commonly separated into "energy," i.e., power provided at a designated MW output for a specified duration (MWh), generally one hour or longer, and "ancillary services," i.e., products relied upon by the system operator to maintain reliability, such as generation capacity available to achieve a designated MW output within a specified interval (MW). Ancillary services are typically needed to meet uncertain loads varying over intervals less than one hour,[1] replace generators on forced outages and to satisfy various network operating requirements that keep the power system operating within allowed tolerances.[2]

[1] Typically, capacity that can respond about every four seconds up and down with high ramp rates (MW/minute) provides Automatic Generation Control/Regulation service; capacity that can ramp up to full loading in less than 10 minutes provides Spinning or Non-Spinning Reserves, and capacity available within about 30 to 60 minutes provides Replacement Reserves. Spinning reserves are online generators already synchronized to the grid, while non-spinning reserves may be off-line when called upon to reach a specified capacity.

[2] The Federal Energy Regulatory Commission has designated six Ancillary Services in Order No. 888: 1) Scheduling, system control and dispatch service; 2) Reactive supply and voltage control from generation sources service; 3) Regulation and frequency response service; 4) Energy imbalance service; 5) Operating reserve – spinning reserve service; and 6) Operating reserve – supplemental reserve service. Black start capability may also be considered as an ancillary service, but it is usually procured separately from the other services.

"Ancillary services" may now be delivered to grid operators and paid for separately from "energy." Since they are contracted in advance, ancillary services are essentially options to purchase energy up to predetermined capacity level at an agreed upon price.[3]

This report reviews the evolving energy and ancillary services markets in the largest of the existing ISO-managed power markets.[4] It shows how unbundling of ancillary services affects bidding and operating decisions by generating plant managers, and it discusses the emerging RTOs, which will be responsible for ensuring that ancillary services are provided. Several examples provide results from a multi-market optimum power flow model, UPLAN, which simulates these multiple product markets. These detailed, integrated simulations demonstrate how the inter-related energy and ancillary services markets behave and illustrate how these multi-product markets can be analyzed to improve grid operations, examine tariffs, maximize profits and evaluate future generation and transmission system adequacy.

These multi-market simulations can also project the significant volatility that occurs in these markets. Such simulations have applications in devising bids for generators selling into these markets and in valuing generation assets and investment decisions. They can reveal the underlying market drivers giving rise to the volatility of forward price curves. The final section discusses how a multi-market simulation combined with AC power flow analysis can be used by RTO managers to evaluate RTO functions, such as power flows, transmission tariffs, and generation and transmission system reliability and adequacy.

The aim of this report is not to suggest what specific structure or regulatory regime markets should adopt, but rather to assess the consequences and implications of these emerging markets. The information will also aid in understanding, on EPRI's behalf, what kinds of R&D is now feasible to meet new needs for market analysis and to manage generation assets.

Regional Power Markets

Various regional markets share a common underlying structure in which a grid operator operates available units under Automatic Generation Control/Regulation (AGC/Regulation) and issues real-time dispatch instructions. Given changing electric loads and the lags associated with making generation equipment available to supply power, real-time markets can be quite volatile. Ancillary services are one response to these circumstances, wherein up-front payments are offered to assure the availability of capacity to meet sudden or changing needs for energy in the real-time market. From the standpoint of actual or potential suppliers of energy, revenues from these markets can be

[3] When energy and ancillary services were provided by a single, integrated set of electric generators with a common owner, the services needed to maintain system reliability (i.e., additional MW) could be considered "ancillary" to the basic provision of electric energy = power x time (MWh). In a competitive market with unbundled services the operations and profitability of each individual generator are of concern to each owner, who attempts to maximize his own profits by providing multiple "energy" and "ancillary services." Of course, each grid operator or buyer attempts to procure the combined energy and reliability products at least-cost.

[4] An Independent System Operator ("ISO") or Regional Transmission Operator ("RTO") will be responsible for operating the transmission grid and dispatching generators to match electric loads, while maintaining grid operations. The functions of emerging RTOs are prescribed in FERC Order No. 2000.

obtained not only through the up-front payments for ancillary services but also, depending on dispatch and settlement protocols, from the real-time energy market itself.

A variety of approaches have been followed in organizing forward and real-time energy and ancillary services markets. Most involve formal market-oriented or market-simulation algorithms, ranging from the tight-pool unit commitment and integrated-dispatch procedures of PJM to the multiple settlement auctions of the California ISO. In Texas, the ERCOT ISO takes a very limited monitoring role, leaving real-time grid operations to member transmission systems.[5]

Ancillary Services in the New Power Business

Business issues associated with the unbundling of Energy and Ancillary Services are considered in the third chapter of this report. First, the problem of covering fixed costs is discussed with attention to occasional price spikes and the role of ancillary service capacity payments in ensuring against these spikes. Locational issues involving both the maintenance of regional and local reliability, and the establishment of appropriate locational price signals for investment in new capacity are examined, as are the roles of ancillary services and real-time energy sales in the operation of thermal and hydroelectric generating plants. Finally, the future of ancillary services and real-time energy revenues is examined; there is no basis for believing that in the long run the problem of real-time response to contingencies will disappear. Thus, additional revenues will continue to be earned through a combination of reliability payments for capacity and occasionally high prices in real-time energy markets that can be earned by those who are able to respond to short-term contingencies.

Simulation Methodology

There are a number of reasons why historical statistical modeling of electricity markets is difficult and unreliable in the changing power industry, and why structural simulation of electricity markets can be quite effective. One key element in any simulation effort is the correct identification of the marginal opportunity costs faced by each generator contemplating sales into one or more product markets. These opportunity costs can be modeled within a structural simulation framework by identifying expected market clearing equilibrium conditions. A rational expectations equilibrium approach, commonly used in large-scale financial and macroeconomic models, is computationally challenging, yet this methodology has been applied by using powerful solution algorithms. Such an approach evaluates the opportunity costs and prices in multiple-product markets and has proven useful to those responsible for project development and for the day-to-day management of generation and transmission assets.

Simulation Applications

Three applications of the Rational Expectations Equilibrium Pricing methodology are reviewed, and compared to the results of analyses based on traditional marginal cost-based pricing. First, the changed bidding behavior of thermal facilities is explored. A

[5] The ERCOT ISO requires only that firm and realizable bilateral contracts be submitted for its oversight and transmission management.

thermal unit that takes advantage of opportunities in the Ancillary Services markets will earn greater revenues and profits than will a unit that participates only in energy markets. Failure to take account of these opportunities will lead to under-valuation of generating facilities and to poor financial performance by these assets. Second, the role of ancillary-service marketing for hydro generation assets is reviewed. Finally, the ability of rational expectations equilibrium pricing methodology to portray and project the volatility of power markets effectively is demonstrated.

Multi-market Modeling for the RTO Manager

Under FERC Order No. 2000, Regional Transmission Organizations ("RTOs") are being created to operate regional transmission systems and satisfy eight minimum functions, including the provision of ancillary services. The RTO manager must offer open access while satisfying operational and market constraints. Numerous buyers and sellers making multiple transactions complicate the problem of determining levels of transmission adequacy and identifying the likelihood of conditions leading to transmission system congestion. This section discusses RTO functions, the analysis of transmission tariffs and various measures of transmission and generation system reliability. Joint analysis of transmission circumstances, generation assets and new market rules are inseparable parts of multi-product power market analysis. Results of UPLAN Network Power Model simulations of generation and transmission system adequacy are presented for the Eastern Interconnection.

REGIONAL ENERGY AND ANCILLARY SERVICES MARKETS

Our focus in this chapter is on the markets for energy and energy-related services. It discusses the market design and operation of U.S. regional power grids, as they are currently evolving.

Market Design Framework

In the past the vertically integrated utilities ensured the quality and the reliability of electricity supply. Electric utilities provided adequate reliability by maintaining appropriate short- and long-term reserves, and they charged customers the cost of providing these reserves. In a competitive environment, these reliability services have been unbundled into several ancillary services. Grid customers can now purchase these services from the market (possibly from the grid operator) to secure the quality and quantity of their electricity needs.

Energy and ancillary services are generally organized into the following markets:

Forward Energy Markets. Formal and informal markets exist in which a seller and purchaser of energy agree on a delivery of energy at a set price at a fixed time in the future. These deals can be bilateral or arranged through formal auctions and may cover periods ranging from many weeks to a single hour in the next day. The outcome of these transactions may be expressed as a set of schedules listing balanced loads and resources.

Regulation. Capacity on Automatic Generation Control/Regulation or AGC is used to maintain instantaneous balance between loads and resources.

Operating Reserves. Operating reserves may be dispatched to deliver energy within a specified delay, often ten minutes. *Spinning Reserves* are on-line and synchronized with governor operations, providing simultaneous frequency and/or voltage support. *Non-Spinning Reserves* need not be operating, but must be capable of synchronization and ramping to a specified output within the designated delay (e.g., ten minutes). Generally the reliability requirement establishes a total requirement for Operating Reserves, based on the projected load and the generation mix used to serve the load. A minimum percentage (typically 50%) of the Operating Reserve must be Spinning. Operating Reserves may be dispatched in response to a contingent event or, as in California, as part of the operator's performance of its balancing-energy function.

Replacement Reserves. Many market designs include a slower-moving reserve product, which allows units previously dispatched from the operating reserve to be backed down and returned to the replacement reserves.

Capacity Reserves. A number of control areas require that energy schedules be supported by a proportionate reserve of *Operable Capacity*, which is available to provide energy and/or Operating Reserves. *Installed Capacity* is another feature in some markets, similar to the *Planning Reserves* in some pre-ISO power pools which required installation of capacity. In a tight pool (in which the ISO takes over operating control of the individual units in real-time), Operable Capacity can be similar to combined Replacement Reserves and Operating Reserves products. Installed Capacity is less directly related to grid operations, providing instead an inducement to longer-term investment in new generation capacity.

Balancing or ***Real-time Energy.*** The ISO or RTO is responsible for maintaining a real-time balance between loads and resources and satisfying NERC operating criteria. This is accomplished through control of generation on AGC, dispatch of units from Operating, Replacement, or Installed Capacity Reserves, and/or through the operation of formal and informal balancing-energy markets.

Market Dynamics

The electricity market consists of the (a) *forward* and (b) *spot* or *real-time* markets. The forward market may include bilateral contracts, futures, options, day-ahead and hour-ahead markets for energy, and, in some regions, ancillary service markets. In the spot market, only energy is traded in real time. Several diverse factors affect the behavior of these markets. Some of these factors are described below.

Market Structure

The structure of regional markets will have significant influence on the market prices. The different structural aspects that play a role in determining market prices are:

- the state of deregulation in that market;
- the rules and protocols that govern the operation of that market;
- the cost of stranded assets and the prevailing policies that permit the recovery of these costs;
- bilateral contracts and other long-standing contracts; and
- the presence of markets for trading in different ancillary services.

Physical Characteristics

The physical properties of the electrical system also significantly affect the behavior of the market. Generation infrastructure and the characteristics of the individual generators, and the supply and the prices of the various fuels will each affect the cost of generation and, thereby, influence the spot prices of electricity. Emission constraints and costs of emission allowances also affect electricity prices. The cost of transporting energy over the transmission network (wheeling costs) and the energy lost as heat also affect prices. Thus, the transmission network, its electrical properties and transfer limits, and congestion in the network can cause locational basis differences in prices.

There is a balance between supply and demand in both the forward and real-time markets. The real-time market functions to accommodate loads and resources that were not transacted in the forward market and to make up for resources that were sold in the forward market but are unable to deliver in real-time. Further, equilibrium must exist between energy generated and energy consumed at every instant, because electricity, unlike most other commodities, cannot be stored.[6] Disturbances, therefore, can have a significant impact on prices.

In any forward market, the market psychology and expectations of future conditions and the anticipated behavior of market participants will also play a strong role in determining forward prices. Prices may reflect the response of market participants to historical behavior in the market, and to expectations about the future behavior of the market.

Other Factors

Other external factors affect market dynamics and long and short-range prices. These factors include:

- weather;
- hydrological conditions;
- load growth; and
- new entrants in the market.

Volatility and Risk

Volatility in electricity prices has two general components:

1. *Market volatility*, arising from the market related factors described abpve and from prevailing market psychology; and
2. *Structural volatility*, arising from the interaction of the various physical factors in the electrical system.

The two components of volatility are related. Market volatility reflects the changing perceptions of future supply and demand conditions. The difficulties of forming expectations, particularly in an environment with many participants and many sources of system perturbation, make market psychology a potential amplifier of the volatility associated with structural changes in the market. There will be residual market risk associated with this volatility, which participants may seek to manage through the use of various financial hedging strategies.

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[6] There are, of course, ranges of commodities, from strawberries to airline seats, which are similarly non-storable.

There are several main sources of structural volatility. Demand volatility is due to the variability of electric demand, which changes, often in response to weather patterns, on an hourly, daily, weekly and seasonal basis. The inability to store electricity produces another source of volatility. The process of generation itself adds randomness directly: any power plant can suffer an unplanned outage or be derated in capacity at any moment, thus requiring replacement capacity to be brought on line. The processes of unit commitment and scheduling depend on the determination of Market Clearing Prices for every hour, which in turn depend on demand and supply bidding by each market participant. All these factors contribute to structural volatility in electricity prices.

Finally, there exists a measure of uncertainty in electricity transmission due to random electric line outages. These could be caused by excessive heating, by equipment failure at transmission substations, by line sagging and contact with ground foliage or by bad weather. Transmission related volatility gives rise to locational basis risk. However, since we are concentrating here on the problems of managing and modeling generation, we do not consider these problems further.

Price volatilities expose the market participants to the following forms of basis risk:

- Locational basis risk, arising from the difference in prices across different geographic regions; and
- Forward/spot basis risk, arising from the difference between the futures price and the cash value of the underlying commodity.

Traders use a variety of hedging instruments to mitigate these risks.

Hedging and Ancillary Services

Market participants exposed to the various forms of risk have several means of mitigating these risks. The most fundamental hedging instruments are bilateral contracts and futures. Futures, apart from ``locking in'' prices, also have some built-in safeguards, such as price discovery and counterparty guarantees. Another strategy is to purchase options on the futures and protect oneself from movements of the futures prices in either direction.

Most electricity markets that have Independent System Operators obtain ancillary services for their customers through auctions designed to procure the required quality and quantity of electric supplies. In regions without ISOs participants may obtain the same results using financial instruments to hedge against uncertainty of delivery or to cover basis risk.

When an ISO procures ancillary services through auction-based procedures, suppliers will seek to provide those products with the highest return, choosing between scheduled and spot energy and the delivery of capacity and energy associated with ancillary services. The market for real-time energy satisfies the imbalances between forward and spot markets. For market-based ancillary services, the system operator first establishes the need for the services, and prices are then determined by achieving a competitive equilibrium between the various markets, so that the participants equalize their marginal opportunity costs (i.e., their profit margins) across these markets and, thus, eliminate arbitrage.

In regions where clearly defined markets do not exist for ancillary services, one can estimate the value of reliability, and hence the effective value of ancillary services, by analyzing the volatility of underlying energy prices. The volatility of energy prices and the implicit value of ancillary services are linked. The volatility reflects the uncertainty of the delivery of the energy and indicates the level of financial risk that the suppliers are willing to take, given the potential for congestion in the transmission system. Participants in these markets can hedge against the risks resulting from volatility in prices by using financial options, contracting for stand-by generators or explicitly paying for reliability products.

Multiple-Product Power Markets in Practice

ISOs now operate five control areas: in the East are the New England ISO (NE-ISO), the New York ISO (NYISO) and the Pennsylvania-New Jersey-Maryland Interconnect (PJM); ERCOT is in Texas, and in the West, the California ISO (CAISO).[7] These five ISOs illustrate the range of centralized control vs. market coordination. PJM acts as a tight pool to manage its allocation of generation between energy and reserves in much the same way an integrated utility would. NE-ISO and NYISO also retain tight control over locational dispatch, but add markets for ancillary services. The CAISO operates without its own forward energy auction by requiring balanced schedules to be submitted for forward energy transactions and by offering its own auctions for ancillary services and real-time balancing energy. The CAISO currently allows its generators real-time latitude to change their generation output without dispatch instructions, but with penalties for uninstructed deviations. In comparison, ERCOT acts entirely as the residual manager of bilateral contracts arranged between market participants.

We now discuss the main features of these markets.

California ISO

The California Independent System Operator (CAISO) is a non-profit corporation charged with exercising day-to-day operational control of California's electric transmission facilities. CAISO's main function is to ensure that all electricity buyers and sellers have an equal opportunity to use the state's transmission system and to ensure that all transactions between buyers and sellers can be executed. It provides open access to the transmission networks owned by the three major Investor Owned Utilities (IOUs): San Diego Gas and Electric, Southern California Edison and Pacific Gas and Electric Company. It manages the reliability of the transmission grid, administers grid congestion management protocols, controls the dispatch of generation and buys A/S services required to maintain supply reliability. Additionally, CAISO coordinates the execution of the day-ahead and the hour-ahead schedules proposed by participants in those markets,

[7] Up to 15 new Regional Transmission Organizations may file applications with FERC by October 15, 2000.

which are now managed by the PX and other scheduling coordinators. Each scheduling coordinator must submit a balanced supply-demand schedule to the CAISO, which purchases ancillary services in the forward market and settles energy imbalances in the real-time market.

CAISO does this through its operation of Ancillary Services (A/S) and Real-Time (Imbalance) energy markets, as well as through market and non-market management of transmission and local-area reliability services. It serves as the control area operator for California, matching electricity output from in-state generation plus out-of state energy purchases minus energy exports to meet the demand under its control. The CAISO controls all power interchanges with other control areas and maintains the frequency of electric power on the transmission grid.

The California Power Exchange (PX), a non-profit corporation, was created in order to provide price discovery by conducting daily market clearing auctions for electricity in the day-ahead and the hour-ahead markets in California. As an outcome of the bidding and auction procedures, the PX creates balanced schedules for submission to the CAISO, along with the balanced schedules of other Scheduling Coordinators. Electricity may also be traded bilaterally, through formal markets, such as that operated by the Automated Power Exchange ("APX") or through other arrangements.

Market Rules

The CAISO is responsible for acquiring or monitoring the acquisition of seven ancillary services, five of which compete on the supply side with energy deliveries. These five are procured by CAISO through day-ahead and hour-ahead auctions and are procured based on a percentage of the load and single part price bids. These ancillary services are Regulation Up and Regulation Down, Spinning Reserves, Non-Spinning Reserves, and Replacement Reserves.[8] Of the four reserve services the Regulation Reserve is provided under Automatic Generation Control (AGC), which can be directly controlled by the ISO operators. The Spinning Reserve service is provided by generating capacity synchronized to the grid, though unloaded, which can respond in less than 10 minutes. The Non-Spinning reserve is provided by generating capacity that is not synchronized to the grid, though it has a fast response capability of 10 minutes or less. The Replacement Reserve service is provided by generating capacity with a response time of 60 minutes or less.

Only within-control-area generators may provide Regulation Up and Regulation Down services. Spinning Reserve providers must be specified generators, but up to half of the spinning reserve capacity delivered to the CAISO may be provided by out-of-control-area (importing) generators. Non-spinning reserves may be provided by either generation or

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Ancillary service requirements for Regulation Up and Down and Spinning and Non-Spinning reserves are imposed on loads in proportion to total (metered) loads, and primarily in proportion to unscheduled loads in the case of Replacement Reserves. In principle each load's obligations for ancillary services may be met by the "self provision" of appropriate capacity by the scheduling coordinator handling the loads, or by the SC's arrangements with another scheduling coordinator to assume the obligation. Loads which neither self-provide nor make an "Inter-SC trade" of the A/S obligation must purchase the A/S requirement from the CAISO, which operates a series of auctions to acquire the necessary ancillary services. In practice almost all A/S capacity delivered to the CAISO is transacted in the CAISO's own A/S auctions.

curtailable loads; imports cannot account for more than half of the CAISO's total spinning and non-spinning reserves. Either generation or loads may also provide Replacement Reserves, and there is no blanket limitation on import participation. However, transmission capacity cannot be reserved for ancillary services; thus, imports of Spin, Non-Spin and Replacement reserves over an intertie cannot exceed the unscheduled capacity of that intertie.

The CAISO procures A/S capacity in a Day Ahead (DA) and an Hour Ahead (HA) auction. The DA auction is run immediately following the submission by scheduling coordinators of their Final Adjusted Schedules and the completion of the CAISO's Day Ahead congestion management procedures. Participants submit bids indicating their reservation prices and capacity offers for Regulation Up and Down, Spinning, Non-Spinning and Replacement Reserves. Auction evaluation of Regulation Up and the three Reserve services is sequential, where lower-priced capacity in the earlier ("higher quality") service may substitute for capacity bid for the subsequent ("lower quality") services. The auction uses a Rational Buyer algorithm, in which quantities that the CAISO purchases of higher-quality services may be increased, and quantities of lower quality services decreased (where the reliability benefits of a lower-quality service might be met by a higher quality service), and when doing so reduces the total cost to the CAISO of procuring ancillary services.

The CAISO allocates its purchases of ancillary services between the Day Ahead and the Hour Ahead iterations following a similar philosophy. It examines the offers to provide A/S capacity in the DA auction, takes into account the offers it expects to see in the HA iteration, and increases or decreases its DA purchases to reduce its total procurement costs.

In both the DA and HA iterations, a single market clearing capacity price is established for each service, unless the CAISO procures A/S zonally, in which case a price is established for each service in each zone. The MCP is the highest capacity reservation price for accepted capacity in each service and iteration; it is paid to all accepted capacity.

Regulation Up and Down capacity is controlled by the CAISO to maintain instantaneous balance between loads and resources. Net energy delivery from regulating units is computed by comparing ex-post metered energy to the scheduled energy of the units; it is settled at the real-time ex-post price that is produced by the CAISO's balancing-energy auction, as described in the next paragraph.

Energy delivered out of the CAISO's A/S capacity is settled separately from the capacity settlement, i.e., when called upon to deliver incremental energy in the real-time market, those units providing A/S receive separate payments for that incremental energy. The capacity bids for A/S Reserves include incremental balancing-energy bid segments, identifying the prices below which blocks of incremental energy may not be dispatched. These bid segments are entered, along with similar Supplemental Energy bids for which there is no associated capacity payment, in the CAISO's balancing energy auction. Resources in the balancing energy auction are dispatched in merit order, based on the incremental price bids, as needed to resolve system imbalances and allow Regulating units to be returned to their initial setpoints. The highest accepted incremental bid during each ten-minute interval (or the lowest accepted decremental bid, which is an offer to buy energy or reduce output) sets the ten-minute interval price. Market design revisions that will be in place before the end of 2000 will pay this price for instructed incremental energy (including the energy provided by Regulation Up capacity), and charge this price to the under-generation and over consumption (relative to schedules) to which the dispatch instructions have responded.

The overall California market design philosophy is permissive: market participants are invited but not required to submit and follow their forward energy schedules. There are few penalties for failure to do so, and few mechanisms to force compliance. The move to 10 minute monitoring and settlements with penalties for uninstructed deviations is intended to tighten up adherence to scheduling and real-time dispatch instructions. Unlike "energy," A/S capacity is viewed as a firm commitment to follow specific dispatch instructions. Thus, while a generator which sells energy in the CalPX forward energy markets need not operate (but thereby incurs an obligation to purchase the contracted energy in the CAISO's real-time market), failure to keep Reserve capacity available for dispatch, either by not running or by generating from that capacity prior to dispatch instruction, results in the generator losing both the capacity payment and payments for any associated uninstructed generation.

PJM

The PJM Interconnection (PJM) is the ISO that controls transmission and generation in most of Pennsylvania, New Jersey, Maryland, Delaware and the District of Columbia, and in part of Virginia. Over 58,000 MW capacity and a 14,100 mile transmission grid are controlled in the PJM pool. It is a centrally scheduled and dispatched "tight pool," in which generators participate by submitting startup, minimum load, and incremental cost data to PJM, which PJM uses in unit commitment and dispatch operations. PJM uses optimization routines to dispatch generators to provide energy or reserves, and establishes locational marginal prices (LMP) at specific nodes within the PJM transmission network to reflect the value of energy at those points, taking into account the constraints associated with grid operations.

Market Rules

The PJM market design includes a number of different products, including installed "capacity resources," a real-time energy market, and ancillary services based on the largest contingency. Market mechanisms such as locational marginal prices, hub pricing, firm transmission rights and a two-way settlement system have been implemented. To participate in the energy and ancillary services markets, a generator must be a capacity resource. Load-serving entities are responsible for either delivering to PJM, or paying for delivery to PJM, sufficient capacity resources to meet both their loads and a contingency margin. The existence of the capacity resource market may provide an additional signal for expansion of generation capacity. However, it does not influence how resources are bid into the actual power markets, acting instead as a possible uplift charge for new capacity, which may supplement the price signals from the energy market.

Our main discussion here is on the interaction between energy and A/S markets. The PJM ancillary services include Regulation and Operating Reserves, with Operating Reserves further subdivided into ten-minute Spinning, Quick-Start, and other 30-minute reserves.

Since June 2000, the PJM Regulation market has allowed market-based bids. Potential suppliers submit a capacity bid, to which PJM adds an "opportunity cost" adjustment to reflect the difference between the expected LMP at the generator's connection bus and the generator's energy supply bid at the set point where the unit would operate if selected to provide regulation. PJM stacks these composite bids, selects the least expensive bids that meet its Regulation Requirement, and pays the market-clearing capacity price to all selected suppliers of Regulation. There is no further payment for energy deliveries from Regulation: the opportunity-cost computation ensures that the costs of deliveries pursuant to Regulation are covered. The Regulation market is operated daily: bids are submitted for the full day, and PJM schedules and pays for the capacity-hours that it needs. The price cap for reserves in May 2000 was $2.52/MWh, but the opportunity cost payment increased average costs for spinning reserves to about $3.10, while non-spinning reserve prices averaged about $2.07/MWh.

Operating Reserves are handled simultaneously with PJM's integrated unit-commitment, dispatch and energy-market procedures, which compute the least-cost dispatch of accepted installed capacity to meet the system's energy and reserve requirements. Multi-part energy bids include start-up, no load and running costs. There is no separate reserve bid. Much of the reserve requirements are met by the merit-order dispatch: high heat rate quick start units provide ten-minute and thirty-minute reserves, while steam units operated at below their maximum output, and hydro units meeting minimum-flow constraints, may provide spinning reserves without incurring opportunity costs. In some cases generation which would be selected in a merit-order energy dispatch is backed down in order to provide operating reserves; these units are paid the difference between the relevant LMP and their energy bid. All units selected for Operating Reserves are paid their LMP, if they are called upon to deliver energy. (The dispatch algorithm ensures that the LMP is always at least as high as all dispatched units' energy bids).

New England ISO

Market Rules

Unlike California, NEPOOL does not have a Power Exchange. All functions are performed by the New England ISO (NE-ISO). In designing the NE-ISO, the experience gained from the operation of the California market was drawn upon to a large extent, so there are several similarities between the two markets.

In New England, the NE-ISO administers five NEPOOL product markets: (1) electric energy ("Energy"); (2) Ten-Minute Spinning Reserve; (3) Automatic Generation Control ("AGC"); (4) Ten-Minute Non-Spinning Reserve; (5) Thirty-Minute Operating Reserve.

A sixth market for Installed Capability was terminated in June 2000.[9] Market participants provide one-part bids for energy to determine the dispatch. Separate bids are supplied for ancillary services to set the prices at which these products are traded.

The energy market is a residual market. "Residual" means that to the extent that a participant in the marketplace produces electricity in excess of the demand of its customers, it can sell the excess into the wholesale market to other participants. The energy market is open to all generators in the NEPOOL control area that can be dispatched in real time and which meet other criteria. Each participant is required to bid any capacity that has not been self-scheduled to meet its own load or sold through a bilateral transaction. This provision is intended to mitigate market power by preventing participants from physically withholding capacity from the market. The ISO uses a unit commitment model to determine a day-ahead, least-cost schedule and the real-time dispatch of generation to meet load based on submitted bids. At least every five minutes, the ISO calculates a market-clearing price for energy that is equal to the bid of the least expensive supply increment (MW) that was not called upon to dispatch. The price to sellers at settlement is the weighted average of these five-minute clearing prices over the hour.

The ancillary service markets are operated in a similar manner. In each market, except for ten-minute spin, generators make separate bids. Hydroelectric generators (including pumped storage) are permitted to bid separately into ten minute spin markets; due to software limitations, all other generators (i.e., non-hydro units) seeking to supply ten minute spin may bid only into a combined auction for energy and ten minute spin. If a generator bidding into the combined market is selected for ten-minute spin, it is backed down and held in reserve rather than being dispatched to the energy market. All suppliers are paid the same market-clearing price.

Capacity that is delivering ancillary services participates in the New England ISO's real-time dispatch, which as noted above computes an energy price every five minutes. These are used to compute an hourly energy price, which is paid for all balancing energy, including energy delivered out of A/S reserves.

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[9] On June 1, 2000 the NE-ISO discontinued the Installed Capability auction and terminated this market. Installed Capability was bought and sold through a monthly auction at a monthly price and was the only product in the New England market that was not priced hourly. The auction related to the residual amount of Installed Capability offered or required by each Participant. An active bilateral market still exists for Installed Capability. In March 2000, that market included 8,719 megawatts subject to contracts longer than a year, 11,738 megawatts subject to contracts longer than a month but not more than a year, and 7,443 megawatts subject to one-month contracts. The total of 27,900 megawatts slightly exceeds NEPOOL's entire installed capability, and represents (to a degree not easily possible to quantify) the trading and re-trading of the same megawatts.

New York ISO

The New York market design falls between the designs of New England and California on the one hand, both of which rely heavily on markets to select units for ancillary services and leave the unit commitment task to the individual market participants, and the tight-pool arrangements of PJM, on the other hand. Like PJM, the NY-ISO performs a unit commitment step (covering a 7-day horizon to take into account slow-starting units), and guarantees coverage of start-up and minimum-run costs for generators it dispatches as part of this process. Like the California and New England ISOs, the New York ISO uses auctions in which suppliers submit capacity bids. In common with PJM and NE-ISO, those generators providing operating reserves whose energy bids are below the relevant market-clearing energy price receive an opportunity-cost payment.

Market Rules

The NY-ISO operates Day Ahead and Real Time markets for both energy and ancillary services. The ancillary services are Regulation, Spinning Reserve, 10-Minute Non-Synchronized Reserve (NSR), and 30-Minute Reserve.

During the Day-Ahead processing, the NY-ISO performs a full-day unit commitment and scheduling procedure, which minimizes bid production cost (including start-up and minimum-run costs), establishes locational energy prices, and schedules ancillary services. At the same time the NY-ISO examines 7-day load forecasts and information about the generating resources that are expected to be available for energy production or could be available. The ISO may instruct generator owners to start up slow-moving units to ensure sufficient capacity over the 7-day horizon.

Following close of the Day-ahead market, and up to 90 minutes before the operating hour, generators may modify bids for resources not scheduled in the Day Ahead market. The ISO uses these bids (and the unmodified bids of other resources that were not included in the Day Ahead dispatch) to meet changing loads and to respond to outages of generation and transmission. A new set of locational energy prices and ancillary-service clearing prices is established, which is applied to transactions in the real-time market.

Congestion-related issues have significantly influenced the operation of the NY-ISO's A/S markets. The Central-East transmission path has often been congested in a West-East direction, so that reserves located west of the path would be unable to respond to a loss of generation in the east. The NY-ISO has therefore required that all 10-Minute non-synchronized reserves be located in the east. However, a few sellers hold most of the relevant capacity in that area, and prices for this product reached very high levels in the first weeks of market operation, early in 2000. The NY-ISO responded by imposing low bid caps in both the 10-Minute NSR and the Spinning Reserve markets. FERC has affirmed the bid cap in the 10-Minute NSR market, but has ordered a return to uncapped market-based bids in the Spinning Reserve market. Owners of resources east of Central East are now required to bid all their available capacity into the 10-Minute NSR market at a capacity price of no more than $2.52/MW. Selected bidders also receive the opportunity-cost payment when they are not dispatched for energy and their energy bid is below the locational energy price.

FERC has instructed the NY-ISO to facilitate self-supply of 10-Minute TSR[10] (and, presumably, the other Operating Reserve products), as well as to allow suppliers of 10-Minute TSR in the west part of the state (1) to provide reserves when Central-East is uncongested and (2) to reserve Central-East transmission capacity for the dispatch of such reserves, even when Central-East is congested.

ERCOT

The ERCOT ISO represents an entirely different model from the other ISOs described above. All the ISOs, except ERCOT, operate some sort of bid-evaluation mechanism to allocate capacity between energy and the required ancillary services. The ERCOT design, in contrast, relies entirely upon bilateral contracts, which must be firm (i.e., carrying adequate operating reserves) and feasible (i.e., accompanied by appropriate reservations of transmission capacity). ERCOT ISO operates no market for either ancillary services or for energy, except for the redispatch necessary to relieve real-time transmission congestion. It has no energy dispatch function, leaving these tasks (as well as the operation of AGC to maintain frequency and intertie schedules) to the various control area operators within ERCOT. The ERCOT ISO does have a monitoring function, in order to assure that submitted schedules are feasible and contain sufficient operating reserves to meet ERCOT's reliability standards.

For a generator participating in the ERCOT market, this does not mean that there is no market for ancillary services. Rather, the market is implicit, based on bilateral contracts with the system's load-serving entities. The generator who is considering providing reserves must make the same sorts of computations as a generator operating in more formal markets. These calculations would evaluate whether the payment offered for reserves will adequately compensate for the lost revenues from energy sales, assess the likelihood of being dispatched for energy, and forecast the terms upon which energy delivery would be settled. The difference is that these various terms, conditions and probabilities are subject to negotiation with the counterparty to the transaction, rather than being published in a FERC tariff.

[10] Ten-minute synchronous reserve