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Effective Design and Monitoring of Electricity Markets

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Abstract

Since the advent of electricity restructuring in early 1980's, a variety of restructuring models have been adopted in different countries. The unbundling of generation from transmission and distribution as separate businesses is prevalent among different models. The transmission sector is generally regarded as a natural monopoly, and remains regulated in order to permit a competitive environment for generation and supply services. Non-discriminatory access and pricing of transmission is generally mandated in order to facilitate competition in wholesale generation and supply.

In most market designs the transmission sector and its products and services are further unbundled accommodating different wholesale market players, products, and services, as well as the provision or trading of products and services as separate commodities. The usual wholesale market players are the Transmission Owners (TO), Independent System Operators (ISO), Power Exchanges (PX) and transmission users or their agents (sometimes called Scheduling Coordinators; SC). The usual unbundling of transmission services includes separation of basic network transport services ("wires" service) from transmission support services ("ancillary services"). The primary market commodities and services are energy, ancillary services, and transmission services (including congestion management and transmission rights).

Experience with deregulated electricity markets thus far has shown that the assumption that markets will naturally produce competitive results is not justified. The existing ISOs and Power Exchanges all have developed or are developing systems and procedures to accomplish the monitoring task in their markets. Market monitoring is concerned primarily with ensuring efficient market performance by identifying and mitigating market inefficiencies, the potential for market

abuses and market power problems.

In this paper, we present an overview of the evolving structural models of the deregulated electricity markets, along with a summary of the usual products and services, and market designs adopted. We also define market power and identify factors that allow the exercise of market power in electricity markets, propose market efficiency objectives that should be used to design market rules that discourage gaming, and provide an overview of the key elements necessary for effective design and implementation of market monitoring systems. Emphasis is placed on the wholesale electricity markets as the first step in electricity restructuring. Retail open access is not treated here in any detail.

1. Intruduction

Electric power industry restructuring is a current theme of very high interest around the globe. The trend started in the 1980's in the U.K. and several Latin American countries, gained momentum in the U.S. and many other countries in the 1990's, and is moving forward globally with different paces in different countries.

The main motivation and driving forces for restructuring of the electric industry in different countries are not necessarily the same. In some countries, such as the U.K. and the Latin American countries, privatization of the electric industry has provided a means of attracting funds from the private sector to relieve the burden of heavy government subsidies. In the countries formerly under centralized control (Central and Eastern Europe), the process has followed the general trend away from centralized government control and towards increased privatization and decentralization; it also has provided a vehicle to attract foreign capital needed in these countries. In the U.S. and several other countries where the electric industry has for the most part been owned by the private sector, the trend has been toward deregulation, i.e., increased competition and reduced regulation. It is important not to confuse privatization with deregulation. Privatization may be implemented under a regulated or deregulated paradigm. Privatization in a regulated regime can be a target state in itself or a first step before deregulation. The focus of this paper is on the deregulated energy markets.

Although a variety of restructuring models have been adopted in different countries, the unbundling of generation from transmission and distribution as separate businesses is prevalent among different models. The transmission sector is regarded as a natural monopoly, and in general remains regulated in order to permit a competitive environment for generation and retail services. In many structural models vertical unbundling involves only a functional separation. This is the case in the U.S., where Order 888 by the Federal Energy Regulatory Commission (FERC) [1] mandated functional unbundling of generation and transmission services, but did not require corporate restructuring. Transmission Open Access (TOA), i.e., non-discriminatory accessibility and pricing of transmission, is generally mandated in order to facilitate competition in wholesale generation.

The transmission sector and its products and services may be further unbundled allowing for different wholesale market players, products, and services, as well as the provision or

1. FERC Order 888 was issued on April 24, 1996; it was superseded by FERC Order 2000, issued on December 20, 1999.

trading of products and services as separate commodities if the transmission users so desire. The most usual wholesale market players are the Transmission Owners (TO), Independent System Operators (ISO), Power Exchanges (PX) and transmission users or their agents (often called Scheduling Coordinators; SC). The most usual unbundling of transmission services includes separation of basic network transport services ("wires" service) from transmission support services ("ancillary services"). The primary market commodities and services are energy, ancillary services, and transmission services (including congestion management and transmission rights).

Section 2 presents a classification of wholesale electricity market structures. Section 3 provides a summary of the usual products and services transacted in these markets. Market monitoring issues are discussed in Section 4. Section 5 provides an illustrative example of existing electricity markets. Finally Section 6 summarizes the conclusions of the paper. Emphasis is placed on the wholesale electricity markets as the first step in electricity restructuring. Retail open access is not treated here in any detail.

2. Structural Classification of the Wholesale Electricity Markets

The basic premise of Transmission Open Access (TOA) is that the transmission providers treat all transmission users on a non-discriminatory and comparable basis regarding access, usage, and pricing of the transmission system and services. This requirement could be difficult to ensure if the transmission providers had any financial interests in energy generation or supply. A general trend is therefore to designate an Independent System Operator (ISO) to operate the transmission system and facilitate provision of transmission services.

Maintenance of the transmission system generally remains the responsibility of the Transmission Owners. The Transmission Owner recovers its revenue requirements (rate of return on investments as well as operating costs) through a combination of Transmission Access Charges (TACs) and Transmission Usage Charges, applied to the users of the transmission system.

Some restructuring models include a Power Exchange. The primary function of a Power Exchange is to provide a forum to match electric energy supply and demand in the forward energy markets. The forward market horizon may range from an hour ahead to a few months ahead. The most usual situation is a day-ahead market to facilitate energy trading one day before each operating day, generally allowing for separate trade quantities and prices for each hour of the operating day. The day-ahead market may be supplemented by hour-ahead markets. An hour-ahead market provides energy trading opportunities up to one or two hours before the operating hour. In its simplest form, a Power Exchange may provide a bulletin board type of an environment for energy suppliers and energy service providers or wholesale energy buyers to engage into bilateral forward contracts. However, the more usual function of the Power Exchange is to act as a pool for energy supply and demand bids, and establish a market-clearing price (MCP). The market-clearing price is then the basis for the settlement of the forward market commitments. Regardless of their asking prices, all selected bidders are paid the MCP. This approach is adopted to encourage the bidders in a competitive market to price energy close to their marginal costs of production.

Transmission users may interact with the ISO through agents called Scheduling Coordinators (SCs). Scheduling Coordinators are entities that put together supply and demand energy schedules without necessarily abiding by the rules of a Power Exchange. The Power Exchange, where it exists, may thus be viewed as a regulated SC. Some structures restrict forward schedule coordination to a central pool and do not permit other SCs to operate. The initial design of the U.K. market (from late 1980's to late 1990's) was an example. In some other structures no central pool or regulated Power Exchange exists; schedule coordination is done in a decentralized manner often by the existing control areas. This is the situation in ERCOT (Texas) and the Mid-West ISO (MISO) in the U.S.

In summary, the various structural models of wholesale electricity markets may be broadly classified as follows:

- Structures with separate ISO and PX - Examples: The initial California Market (April 1998 to January 2001), Norway, and Alberta (Canada)
- Structures with merged ISO/PX - Examples: Pennsylvania-Jersey-Maryland (PJM), New York ISO (NYISO), and Victoria Power Exchange (VPX)
- Structures with merged ISO/PX/TO - Example: The initial National Grid Company (NGC) market (U.K.)
- Structures with no Scheduling Coordinators - Examples: The initial NGC (U.K.) and Alberta (Canada)
- Structures with no Power Exchange - Examples: Texas (ERCOT) and Mid-West ISO (MISO)

Exhibit 1 provides a schematic representation of several existing and emerging structures.

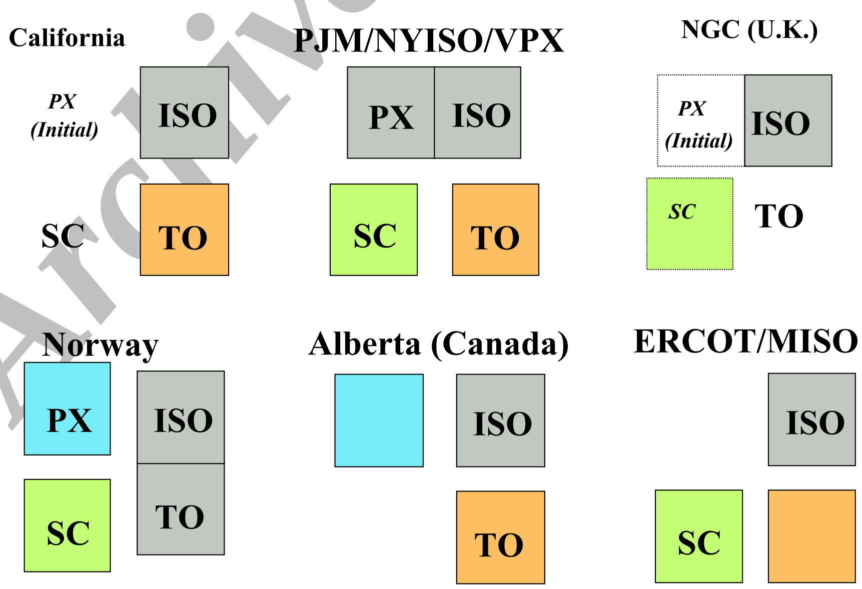

Exhibit 1 – Representative Structural Models of Wholesale Energy Markets

The structure adopted in each case is to a large extent influenced by the scope of responsibilities and authority delegated to the entity responsible for the day-to-day operation of the transmission system, i.e., the ISO. A more detailed discussion of this issue is provided in Ref. [1].

Experience with the electricity markets so far has shown that a **mandatory** Power Exchange as an entity separate from the ISO is not a desirable construct. If the makes rules of the ISO and the PX are not carefully aligned, such separation may lead to unintended adverse consequences. Voluntary Power Exchanges or Bulletin Boards can emerge if the market participants decide that they need such services to help them put together their forward market schedules. A combined ISO/PX, with well-designed market rule set can provide the scheduling services the market participants may desire while leading to an efficient market outcome.

3. Classification of Markets, Products and Services

The products and services traded in the restructured electricity markets can be broadly classified as follows:

- Energy
- Capacity, including Installed Capacity (ICAP) and Ancillary Services (A/S)
- Transmission, including physical transmission rights, congestion management services, and financial transmission rights (FTRs)

The products and services may be traded in the forward financial markets, or in physical markets. The most common markets are:

- Long-term bilateral markets – These are financial markets longer than one day prior to the Operating Day; they are generally not under the purview of the ISOs[2].
- Day-ahead markets – These are generally financial markets one day before the Operating Day; they are facilitated by either the ISOs, Power Exchanges, or both.
- Hour-ahead markets - These are generally financial markets one to several hours before the Operating Hour; they are facilitated by either the ISOs, Power Exchanges, or both.
- Real-time market – This is usually a physical market close to real-time (e.g., based on 5-minute or 10-minute dispatch), generally under the purview of the ISO.

3.1. Single and Multiple Settlement Markets

Where multiple markets are facilitated by the ISO (or PX), the settlement of charges and payments can be based either exclusively on the final (physical) market, or also on the intermediate (forward financial) markets. The former is called a single-settlement market design. The latter forms a multi-settlement market design. In the latter case settlement in each market is based on changes with respect to schedule changes with respect to the previous market.

For example, in the U.S., the Pennsylvania-Jersey-Maryland (PJM) market was a single settlement system since it started operation (April 1, 1997) until June 1, 2000; the day-ahead market was used for unit commitment purposes only. The New York ISO (NYISO) started operation on November 18, 1999 with a two-settlement system – day-ahead and real-time. Final day-ahead quantities and prices for energy, reserves, and congestion are financially binding; deviations from day-ahead schedules are settled in the real-time market based on real-time nodal prices. An hour-ahead market also exists, but it

2. Capacity markets and Financial Transmission Rights (FTR) markets may have a monthly, seasonal, annual, or even multi-annual time horizon; these may or may not be facilitated by the ISO.

is advisory (for information only) and does not establish financial commitments. However, availability declarations and bids offered in hour-ahead are binding and remain available to the ISO to use in real-time as needed. ISO New England (ISO-NE) started its market operation on May 1, 1999 with a single (real-time) settlement system. It switched to a two-settlement system (day-ahead and real-time) on March 1, 2003. California ISO (CAISO) and California Power Exchange (CalPX) started operation on April 1, 1998, with a three-settlement system (day-ahead, hour-ahead, and real-time)[3]. The day-ahead schedules are financially binding; hour-ahead schedule changes with respect to the final day-ahead schedules (and bids accepted in the hour-ahead market) are settled based on hour-ahead market-clearing prices. Real-time deviations from final hour-ahead schedules (including real-time incremental or decremental dispatch compared to hour-ahead schedules) are settled based on real-time market clearing prices.

The evolving standard practice is to have a two-settlement system, including a financially binding day-ahead market, and a physical real-time market for balancing energy (i.e., changes from the day-ahead schedules and forecasts).

3.2. Products and Services

A brief explanation of the most common product and services and their bidding, commitment, scheduling, or dispatch in the forward or real-time markets is presented below.

3.2.1. Energy

Energy markets facilitated by the ISOs and/or Power Exchanges, generally include the day-ahead and real-time energy markets, and may include an hour-ahead market in between. In facilitating a forward (day-ahead or hour-ahead) energy market, the ISO/PX may or may not offer a Unit Commitment service. In some cases (such as NYISO) submission to a centralized unit commitment offered by the ISO/PX is mandatory. In some other cases (such as California)[4] no unit commitment service is offered; decentralized unit commitment is then the rule. In some other cases (such as PJM) submission to centralized unit commitment is voluntary.

The unit commitment service allows the bidders to specify separate bids for start-up ($ per start up), no-load or minimum-load ($ per hour) and energy ($ per MWh). This is referred to as a multi-part bid. The unit commitment service also provides for inter-temporal constraints of the resource (such as start-up time, minimum run time, minimum down time, and inter-hour ramp rates). By contrast, in the decentralized unit commitment paradigm the market participants internalize their start-up and no-load costs as well as up time and down time risks in their energy bids. This is called a single-part bid.

3. CalPX stopped operation on January 31, 2001 after the energy crisis culminated in California leading to the bankruptcy of two of the three major Investor Owned Utilities (IOUs) in California. A redesign of the California market is underway, whereby the CAISO will also facilitate a forward energy market starting in 2004.

4. The deregulated electricity market in California is being redesigned. The new design is expected to become operational during the year 2004. Unless qualified as a feature of the redesigned California market, the design features mentioned here for California refer to the market design presently in operation.

The advantage of centralized unit commitment is that it results in a more efficient use of resources. Its potential disadvantage is that it follows mathematical outcomes rather blindly (e.g., it may commit an extra unit just to satisfy a fraction of a MW). The advantage of decentralized unit commitment is that it allows the bidders to internalize intangible benefits (e.g., use of green energy which may be more expensive than fossil energy, but is more environmental friendly). It also allows the bidders to use economic and risk judgment regarding committing an otherwise marginal resource compared to going a bit short to the subsequent market, where they can make up for the shortfall[5]. Its potential disadvantage is that it is oblivious to the benefits (more efficient market outcome) of pooling the resources from different suppliers.

Regardless of whether a single-part bid or a multi-part bid system is adopted, the energy bid may include several bid segments ($/MWh) depending on the amount of energy offered (e.g., a separate $/MWh price for each block of energy from the same unit or portfolio of units). The energy bid "curve" must be monotone (monotone non-decreasing for supply bids and monotone non-increasing for demand bids). The energy bids may be piecewise linear (e.g., in California PX)[6], piece-wise constant (e.g., in California ISO), or defined by segments involving a slope and an intercept (e.g., in PJM). Exhibit 2 shows examples of energy bid curves. In cases where the market design is based on single-part bids, a simple market clearing process based on the intersection of supply and demand bid curves may be sufficient to determine the market-clearing price and the winning bids and schedules for each hour. However, if the market design is based on multi-part bids, a unit

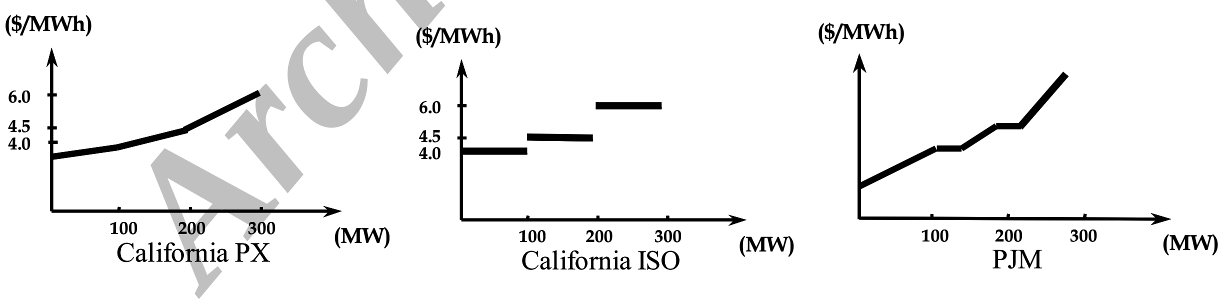

Exhibit 2 – Examples of Supply Energy Bid Curves

5. Although the price in the subsequent market may be higher, the risk is limited since the quantity shifted to the subsequent market is small.

6. California PX ceased operation in January 2001 following the melt down of the California market. References to California Power Exchange pertain to the period when it was in operation (April 1988 through January 2001)

commitment software, possibly with enhancements to take into account security constraints (Security Constrained Unit Commitment, SCUC) may be needed.

The energy market-clearing price (MCP) is generally established by the energy bid curves only, although in the multi-part bid systems, start up and no-load/minimum-load bids are also included in the optimization (bid cost minimization) process. A market design issue relevant to multi-part bid systems is how to ensure recovery of start-up and no-load (or minimum-load) costs when a bid is selected. The usual approach is to pay the MCP for energy, compute the net profits (difference between MCP and the bid price) for the commitment cycle (e.g., a day), an pay an uplift to the supplier to the extent the market profits are not adequate to make the supplier whole with respect to start up and no-load/minimum-load costs. To avoid gaming, the start-up and no-load/minimum-load bids are either cost-based (adjusted for changes in fuel prices only), or bid but kept unchanged for a per-specified time period (usually six months to a year). Moreover, to avoid perverse incentives, in most market designs the uplift payment is revoked if the supplier self schedules, plays in bilateral markets, or engages in uninstructed real-time schedule deviations (price chasing) during the commitment cycle[7].

3.2.2. Ancillary Services

Ancillary services (A/S) are needed for reliable operation of the power system. The majority of ancillary services are in fact real or reactive power/energy resources needed to operate the transmission system in a secure and reliable manner.

Depending on the organizational structure adopted, ancillary services may be traded in bilateral arrangement, in the Power Exchange, in the ISO market, all of the above. In either case the ancillary services may be provided in a bundled manner or as an unbundled menu. In the U.S., FERC Order 888[8] requires the ISO (Transmission Provider) to offer some of the ancillary services in an unbundled manner, giving the transmission users the choice to either self provide or request the ISO to provide them. Four of these services, namely, regulating reserve, spinning reserve, supplemental operating reserve (non-spinning reserve), and energy imbalance, may be self-provided by the user of the transmission system. In case the transmission user does not provide them (directly or through third party arrangements), the user must purchase them from the ISO. The ISO must offer these services, and will usually procure them through a competitive auction in the forward market and charge the users according to their ancillary service responsibility not self provided. Two other ancillary services, namely reactive power/voltage support and system control/re-dispatch are procured and provided by the ISO, and the users must purchase them from the ISO. In fact, these are the six ancillary services that FERC requires the ISOs in the U.S. to offer.

Some other transmission support services, such as loss compensation or backup support, may or may not be offered by the ISO. The term Interconnected Operations Services (IOS) is sometimes used to include all ancillary services including, but not limited to, those mandated by FERC. Exhibit 3 lists the IOS and its FERC A/S subset. In the case of California, black start is included among ancillary services to be provided by the California ISO, and a special ancillary service (Replacement Reserve)[9] is defined to cover the discrepancies between the ISO load forecast and the forecast (preferred

7. A resource may self commit, in which case it would not be eligible for start-up and no-load cost recovery other than what it makes up through its market profits; it would then not matter if it plays in bilateral markets and/or chases the price in real-time.

8. The Ancillary Services specified in FERC Order 888 were also maintained in FERC Order 2000 on Regional Transmission Organizations (RTOs) issued on December 20, 1999.

9. Replacement Reserve is dropped as an Ancillary Service in the redesigned California market.

schedule) by market participants (SCs).

Exhibit 3: Ancillary Services and Interconnected Operations Services

FERC ORDER 888 ANCILLARY SERVICES	OTHER IOS (NERC)
Regulating Reserve (*)	Black Start
Spinning Reserve (*)	Loss Compensation
Operating (Supplemental) Reserve (*)	Dynamic Scheduling
Energy Imbalance (*)	Backup Support
Reactive Supply/Voltage Control	Load Following
Scheduling, System Control & Dispatch	

(*) These ancillary services may be self-provided, bid into the ISO market, or purchased from the ISO.

The bidding and scheduling protocols adopted for the provision and procurement of ancillary services will dictate the complexity of the applications needed. "Optimal" procurement of ancillary services may entail simultaneous processing of energy and ancillary service bids, if allowed by the market protocols. An example of a market where this procedure is adopted is New York ISO (NYISO). Some market structures, such as the existing California market, require separate market clearing mechanisms for energy and ancillary services. In fact in California the processing of different ancillary services is carried out sequentially[10]. This may, however, result in non-optimal procurement, i.e., higher cost of ancillary services to the transmission users and the end-use customers. This approach originally adopted in California, was revised and replaced with a "rational buyer" approach to ancillary service procurement. The Rational Buyer procurement, is a payment minimizing procedure (rather than the bid-cost minimization objective adopted in other simultaneous or sequential procurement models). It permits substitution of services where technically feasible (e.g., purchasing more spinning reserve to satisfy non-spinning reserve requirements) when doing so reduces the total payment to the suppliers for ancillary services procured by the ISO. Ref. [2] provides a more detailed discussion of the Rational Buyer approach.

10. In the redesigned California market, expected to go into operation in 2004, the Energy and Ancillary Service markets are cleared simultaneously, along with congestion management.

3.2.3. Congestion Management

Transmission congestion (called just "congestion" for brevity) occurs when the schedules submitted to the ISO cannot all be dispatched as they stand, because to do so would overload one or more transmission pathways. Congestion may occur in the forward market (day-ahead or hour-ahead) or in real time.

Congestion in the forward markets is a condition where there is insufficient available transmission capacity to accommodate all submitted energy schedules simultaneously. The ISO manages forward market congestion adjusting the submitted schedules to keep the flows on all transmission pathways within acceptable limits, while allocating transmission capacity based on physical or financial rights and/or the economic value of transmission as expressed though "adjustment bids" which are submitted along with the day-ahead (and hour-ahead) energy schedules. Upward and downward adjustment bids indicate the economic value of incremental changes to a resource schedule as perceived by the bidder. Moreover, if the ISO facilitates a forward energy market, submitted energy supply and demand bids are used not only to clear the energy market, but also to manage congestion. In a workably competitive market, adjustment bids should reflect the incremental cost of each resource. In the case of bilateral trades, adjustment bids may also reflect contractual penalties for non-delivery. The price of transmission usage is generally the difference between locational price of energy at the sink, i.e., point of receipt (consumption) and the source, i.e., point of delivery (generation) of energy in the transmission network. The schedules accepted in the direction of congestion pay and those in the opposite direction receive transmission congestion rents. The net congestion rent is paid to the owners of the transmission path or the holders of transmission rights on the path (or to the holders of transmission rights from the relevant sources to the relevant sinks).

Some parties may hold physical transmission rights (called Existing Transmission Contracts or ETCs) or financial transmission rights (FTRs) which mitigate their risk of being adversely affected by congestion. Such parties can conveniently submit their preferred schedules (commensurate with their transmission rights) with no need to submit adjustment bids. Some parties who do not possess such rights may also elect not to submit adjustment bids. When a resource schedule is submitted with no adjustment bids, the ISO treats it as a price taker in the congestion management markets (or in the energy market if one exists).

Congestion in real time is a condition where there is insufficient transmission capacity to accommodate imminent load, generation, and interchange conditions, or to permit dispatching the preferred resources (based on the economic merit order in the real-time supply stack) to eliminate a system-wide, real-time energy imbalance. In a single settlement system congestion is priced and settled only in real-time. In a multi-settlement system, energy is priced and settled in the forward market based on forward schedules and incremental energy (actual generation or consumption minus forward generation or consumption schedule) is priced and settled in real-time based on real-time prices. In that case, congestion is priced and settled in the forward market (day-ahead/hour-ahead), and is generally not explicitly priced and settled in real-time. Generators get paid the real-time locational energy price[11] for their incremental generation (above the forward scheduled levels) and loads pay the real-time locational energy price for their incremental consumption (above the forward scheduled levels). There is then generally a net collection by the ISO that reflects the real-time incremental cost of congestion management. The net collection may be disbursed back to the load (loads implicitly pay for real-time congestion relief by virtue of their locational energy prices).

4. Market Monitoring

Market monitoring has proved to be an indispensable function in the

11. The "locational" price may be a zonal or a nodal price depending on the granularity of the underlying network model and transmission constraints used in real-time pricing.

deregulated electricity environment. In the implementation of existing ISO systems, the ISOs focused primarily on modifications and enhancements to the traditional power system operations and control systems commensurate with market driven scheduling and dispatch processes. Market Monitoring Systems (MMS) were, in general, neglected in the initial specification and implementation of these systems. The existing ISOs have market monitoring units and have developed, or are developing, systems and procedures to accomplish this function in their respective areas of responsibility.

Essential to market monitoring is effective market analysis. In a narrow sense, market monitoring focuses on observation of the market operation and detection of inefficient outcomes. Market analysis has a broader scope that includes the identification of market rules that permit, and actually create incentives for, these market inefficiencies. The market analysis function also encompasses the development of rules and measures to mitigate behavior leading to such inefficiencies.

Identifying the ability of one or more market participants to exercise market power at any time or just under specific system and market conditions is central to vigilant market monitoring. Market monitoring must be able to detect conditions that allow the exercise of market power, quantify the magnitude of market impact, and propose mitigation measures and recommend penalties, if needed, to deter the uncompetitive behavior. Where possible, preventive mitigation measures are preferred to after-the-fact imposition of penalties and sanctions. Gaming of market rules is another issue of primary concern to the market monitors. Generally, market structures, designs and rules that align market efficiency with the profit-maximizing incentives of the suppliers are less prone to the exercise of market power and gaming. References [3] and [4] describe a possible framework for the design of market monitoring programs and systems. In the framework adopted here market monitoring is considered to include the market analysis function.

4.1. Market Power, Market Efficiency and Gaming

In order to establish a common vocabulary to avoid confusion, it is useful to define the terms market power, market efficiency, and gaming.

4.1.1. Market Power

Market power is the ability of a seller to profitably maintain prices above competitive levels for a significant period of time.[12] The "significant period of time" in the commodity markets is usually measured in years (e.g., 1 or 2 years). Experience in deregulated electricity markets shows that huge damage can be inflicted to the energy markets if the ability to exercise market power prevails for a small fraction of that time.[13] References [5] and [6] provide clear examples.

Market power can be exercised primarily in one of the following ways:

12. Market power may also be exercised by buyers. But experience with the deregulated energy markets has thus far shown that sellers are in much better position to exercise market power. The present discussion deals exclusively with the sellers' market power.
13. This was clearly demonstrated in California during summer and Fall 2000, when in a time span of a few months, huge transfers of wealth moved from the load serving entities to power suppliers and marketers.

- Economic Withholding - Economic withholding means bidding excessively above the marginal cost of production and driving up the price.
- Physical withholding - Physical withholding is when a seller withholds some of its available capacity from the market thus reducing effective supply and driving up the price it receives for the rest of its portfolio. The extra profit on the rest of its portfolio generally far exceeds the loss of profit from the withheld capacity. Physical withholding may be exercised by: 1) Not scheduling or bidding part of available capacity, or 2) Declaring false unit outages.

These strategies would not work in a competitive market with abundant supply. The seller would lose market share without receiving additional profit on the portfolio withheld from the market. In deregulated electricity markets, however, competitive conditions do not always exist. In practice, even in markets where the most dominant net sellers have relatively small market shares (less than 10%), they have been able to exercise market power and reap substantial profits (see Ref. [5] and [6]). During periods when system demand is very close to the total available supply, the absence of demand elasticity (which is the case in most electricity markets in real time) allows even a supplier with a small percentage of total market capacity to become pivotal, i.e., be in a position where without its supply, the demand cannot be met. In this situation, pivotal suppliers can charge any price the market can bear.[14]

4.1.2. Market Efficiency

Market efficiency in the short term refers to a market outcome that maximizes the sum of the producer surplus and consumer surplus. With respect to generation, market efficiency will result when the most cost-effective generation resources are used to serve the load. In the bid-based deregulated environment, this would result if generation is bid at variable cost. An exception would be bidding energy-limited resources, where the bid would generally have to reflect, not just the variable cost of production at the time, but also the opportunity cost of generating at a later date. Long-term market efficiency results from choosing the optimal level of investment in generation, transmission, and conservation and demand response programs.

4.1.3. Gaming

Gaming is market participants engaging in uncompetitive behavior that takes advantage of certain market rules and system conditions by deviating from normal bidding, scheduling and operating patterns. Gaming may result in decreased system reliability, increased costs for other market participants and/or an overall reduction in efficiency for the entire market.[15] References [7] and [8]

14. Market power can also be location specific (Locational market power). When a power system is constrained (e.g., by maintenance or a forced outage of a major transmission line) suppliers with small shares on a system-wide level, may suddenly find they have a significant market share on a locational basis. They may be able to exercise market power within the constrained area.

15. Several gaming practices used by the Enron Corp. in California's energy market were recorded by Enron's attorneys in December 2000, and became the subject of extensive investigation by FERC and the California state authorities in early 2002. The California ISO Department of Market Analysis (DMA) had identified the potential for these games, had managed to get FERC's approval for appropriate market design changes to deter some of the games, but was unsuccessful in getting FERC's approval for penalties and

provide detailed examples. Gaming can be distinguished from normal arbitrage in that arbitrage involves activities which cause market price differences to converge, offers no barriers to entry, allows others to protect themselves, helps lower overall cost of production, and has little detrimental impact on system reliability. Gaming usually has detrimental impacts on system reliability by increasing real-time congestion, lowering the level of transparency to the system operators, and deviating from dispatch instructions. Some forms of gaming can be reduced by improving market design and rules. Other gaming may be discouraged with sanctions and penalties.

4.2. Bid Caps and Price Caps

Price spikes are normal in the face of scarcity. However safety net measures are needed to protect exorbitant prices where demand is unable to respond to price signals. To guard against exorbitant price spikes, bid caps and price caps are usually established as safety nets in the deregulated electricity markets.

In PJM a permanent energy bid cap of \$1000/MWh is enforced. However, the locational marginal prices (LMPs), used for settlement, can be higher than \$1,000/MWh and can go negative. The highest and lowest hourly LMPs used for settlement in PJM have been \$1,200/MWh and -\$300/MWh, respectively[16]. In ISO-NE and NYISO a temporary energy bid cap of \$1,000/MWh has been in place since July 2000[17]. The highest energy price (prior to enacting the 1,000/MWh cap) were \$6,000/MWh, and the lowest price -\$2.75/MWh. In NYISO, the highest and lowest hourly locational-based marginal prices (LBMP) used for settlement have been \$1,000/MWh and -\$100/MWh, respectively. In California, the energy bid cap in the PX forward energy market was \$2,500/MWh; however, during the period from start-up of the market until the implementation of the so-called “soft cap” (December 8, 2000) in the ISO real-time market, the “hard” price cap in place in the ISO’s real-time energy market[18] acted as a de facto cap on PX forward energy prices. The unconstrained day-ahead PX price did not exceed the ISO hard cap during this period. However, the implementation of the soft cap removed the restraint on the PX prices, which soared to above \$1,500/MWh on December 13, 2000 and stayed generally above the soft cap for the rest of December 2000 (a month before the PX ceased operation).

sanctions requested to be in place at the start of the market.

16. Although the bids are constrained to be non-negative and capped at \$1,000/MWh, the interplay between congestion and looped network structure can give rise to locational prices that are negative or exceed the bid cap.

17. In ISO-NE, the \$1,000/MWh cap is applied only if the ISO determines that its day-ahead unit commitment cannot meet the total system forecast load and reserve requirements.

18. The real-time price cap in California ISO started at \$125/MWh upon startup on April 1, 1998 and subsequently was changed to \$250/MWh on May 18, 1998; \$750/MWh on October 1, 1999; \$500/MWh on July 1, 2000; and \$250/MWh on August 6, 2000. The notion of a soft cap was implemented as of December 8, 2000. A soft cap is a cap on bids that are allowed to set the market-clearing price; bids accepted above the soft cap are paid “as bid” subject to cost justification (or refund if unjustified). The soft cap at the time of the writing of this paper (August 2003) is \$250/MWh. Various levels of soft cap (\$91.87, \$108, etc. tied to gas prices) were in force in between.

4.3. Market Monitoring Functions

At present there are no standards and specifications for Market Monitoring Systems (MMS)[19]. There is a pressing need to develop such standards with a view to a potential hierarchical (e.g., ISO, regional regulatory agencies, government oversight agencies) market monitoring responsibilities (see References [3] and [4]). To promote market efficiency and guard against exercise of market power, gaming, and market abuse, market monitoring programs and systems must address the following areas at a minimum:

1) Generation and transmission outage monitoring
2) Monitoring the structural framework within which the market runs
3) Monitoring of supply and demand conditions and market performance
4) Monitoring of potential or actual exercise of market power

Monitoring of market participants' activities and transactions ("behavioral monitoring")

Each of these areas is briefly discussed below.

4.3.1. Generation and Transmission Outage Monitoring and Coordination

The basic monitoring functions in this category are:

Generation Maintenance Coordination – Supply adequacy can greatly reduce the potential for the exercise of market power. Coordination of generation maintenance would ensure that maximum amount of generation is available during peak demand periods. The ISO is in the best position to accomplish this coordination task without revealing confidential information from its market participants. Adherence to scheduled maintenance would then be monitored to guard against strategic outages.

Generation Outage Monitoring – Generation unit forced outages can, and do, occur. But, physical withholding can be exercised under the pretext of forced outages. The market monitoring program should include outage standards and have appropriate penalties and sanctions for physical withholding under the pretext of forced outages.

Transmission Maintenance Coordination – Transmission outages can result in geographical segmentation of the market and exacerbate the potential for the exercise of market power. Coordination of transmission and generation maintenance can greatly reduce the potential for the exercise of market power. The ISO is in the best position to accomplish this task. Monitoring transmission outages is important to guard against both strategic transmission outages and exercise of market power in the generation market.

4.3.2. Monitoring of Structural Framework and Changes in Structure

The main monitoring areas in this category are monitoring of market concentration, supply adequacy (generation and long-term contracts), level of demand response, and transmission adequacy and expansion plans. Each of these is discussed briefly below.

19. The existing MMS are often home grown and developed in a piecemeal fashion after the implementation of the market and operations systems.

4.3.2.1. Monitoring and Tracking of Market Concentration

Classical structural indicators such as the Herfindahl-Hirshman Index (HHI)[20] have proved ineffective in the deregulated electricity markets. An HHI of 2000 is often viewed as a reasonably competitive market condition in the commodities markets. However, as mentioned above, in the electricity markets even with no seller having more than 10% market share (an HHI below 1000) substantial market power has been exercised (see Ref. [5] and [6]). A primary reason is the lack of price responsive demand. Another reason is that the dynamics of demand and supply balance change from hour to hour due to outages, ramp rate limitations, temporary system bottlenecks, and variability of demand. It is, therefore, essential to track the ability of market participants to exercise market power using methods and indicators specifically designed for the electricity markets. Two such indicators are described below[21]:

4.3.2.1.1 Residual Supply Index

For a particular market at a particular hour, the total supply capacity of each firm i can be represented by q_i, (i=1, 2, …n), where n is the number of suppliers in the market.

For a given level of demand, D, the Residual Supply Index (RSI) for firm i, which measures the percent of supply remaining in the market after subtracting firm i's capacity of supply, is defined as:

$$RSI_i = (Sum(q_1,\ldots q_n) - q_i) / D$$

When residual supply is greater than 100 percent, suppliers other than firm i have enough capacity to meet the demand of the market, and firm i has less influence on the market clearing price. On the other hand, if residual supply is less than 100 percent of demand, firm i is needed to meet demand, and is, therefore, a *pivotal player* in the market. As a pivotal player, firm i has complete control of the market clearing price and can set the price as high as the price cap allows.

An overall RSI for the entire market can also be calculated. The RSI for a market in a given time period (e.g., hour) is the minimum of RSI_i among all suppliers in the market, or the RSI_i corresponding to the largest supplier Based on empirical evidence compiled by the CAISO Department of Market Analysis, an RSI exceeding 120%-150% is an indicator of a reasonably competitive market. (See Ref. [9] for more detail)

Computation and tracking of the pivotal suppliers using RSI is an essential function that should be supported by the Market Monitoring System.

4.3.2.1.2. Monitoring of Affiliate Groups and Affiliation Changes

It is important to monitor the ability to exercise market power, not only for individual market participants, but also collectively for affiliated market participants.[22] This is particularly important in electricity market segments such as Firm Transmission Rights

20. The HHI is a market concentration index calculated as $HHI = (100 \times S_1)^2 + (100 \times S_2)^2 + \ldots + (100 \times S_n)^2$, where S_i is the market share of firm i. For example, when there are five equal-sized firms in the market, the HHI would be $HHI = 5 \times (100 \times 0.20)^2 = 2000$.

21. These indicators have been developed by the California ISO Department of Market Analysis, with the author's participation.

22. According to the definition adopted by FERC (U.S.A), an affiliate is an entity, company, or person that directly, or indirectly through one or more intermediaries, controls, or is controlled by, or is under common control with the subject entity, company, or person.

(FTRs) where the concentration may change continuously by virtue of secondary market transactions.

4.3.2.2. Monitoring of Long-term Supply Adequacy & Demand Response

Monitoring the long-term supply adequacy and provisions made to ensure adequate supply is extremely important to the proper functioning of the deregulated energy markets. In fact, one of the main elements contributing to the melt down of the California electricity markets beginning in mid-2000 was the lack of adequate provisions to ensure long-term supply adequacy.

The main indicators of long-term supply adequacy are generation reserve margin, demand responsiveness, and long-term contracts. These are briefly explained below.

- Generation Reserve Margin - Before deregulation, planning reserve was used as a measure to ensure adequate supply to meet long-term forecast peak load. With establishment of deregulated energy markets, different ISOs adopted differing measures. These ranged from no specific requirement in California (total dependence on the investment decisions by the market), to a combination of installed capacity (ICAP) requirements, unforced capacity requirements (UCAP)[23], and available capacity requirements (ACAP) in the PJM, New York, and New England ISOs. A developing trend is to define a reserve margin based on 1 day in 10 years loss of load probability (LOLP); the reserve margin is then to be met by a combination of generation, demand response, and long-term supply contracts.
- Demand Responsiveness - Price responsive demand is a very important defence mechanism against exercise of market power by suppliers. Demand response to real-time prices in the competitive environment is generally in a stage of infancy. Monitoring the level and deliverability of demand response is an important monitoring function.
- Long-term Contracts - Long-term contracts are effective hedging instruments for load against the potential exercise of market power by the suppliers in the spot markets. A major problem leading to the collapse of the California energy market was the limitations imposed on California investor-owned utilities to enter into long-term contracts. Monitoring the supply available through long-term contracts for different time frames (multi-annual, annual, seasonal, monthly, weekly and daily) and/or peak, off-peak, and shoulder hours is an important function.

4.3.3. Transmission Adequacy and Expansion

Transmission bottlenecks can degrade system reliability and also can give rise to locational market power concerns. In the deregulated environment, transmission expansion can be accomplished through integrated analysis and planning with a regulated rate of return on transmission investment, merchant transmission projects, or a combination thereof. Under the regulated rate-of-return mechanism, the transmission owner receives an access charge, transmission rights may be auctioned, and their proceeds are used to offset the revenue requirements. Under the merchant transmission mechanism, transmission rights are allocated to the transmission owner. In

23. UCAP = ICAP * (1 – forced outage rate)

both cases transmission rights may generally be traded in the secondary markets. Monitoring of transmission ownership, control and usage is an important market monitoring function.

4.3.3. Monitoring Market Supply and Demand Conditions and Performance

The main monitoring functions in this category are:

- Price Monitoring –Tracking price movements provides the initial assessment of market performance. It should include all energy and ancillary services markets.
- Bid sufficiency – Monitoring sufficiency of bids supplied in different product markets (energy, ancillary services, congestion management) and in various time frames (day-ahead, hour-ahead, and real-time) is a crucial element for ensuring a properly functioning market.
- Total cost of each product market – The bottom line indicator of success or failure of a deregulated electricity market is the price charged to the consumers. Tracking the cost of obtaining each product from the market (and the corresponding cost per MWh of load) is an important indicator that could alert the market monitor to focus attention on specific market segments for possible gaming, exercise of market power, or to recommend modifications to market design or operating procedures.
- Price cost mark up – Price cost mark up measures the extent to which suppliers are successful in setting market-clearing prices above competitive levels. Market prices are compared to a competitive benchmark, which is the system marginal cost to serve the demand. This cost will depend on available supply resources and their variable costs, which are affected by natural gas prices, hydro availability, availability of imports, etc.

4.3.4. Market Power Monitoring

The main functions in this category are:

- General Market Power Monitoring – Market price is driven by many demand and supply factors. Price can fluctuate even in a perfectly competitive market. Therefore, it is important to estimate a long-run measure of competitive market outcomes and compare the actual market prices to this benchmark. The 12-month rolling average price-cost markup, developed by the California ISO Department of Market Analysis, is an effective measure for this purpose. It measures the 12-month rolling average of actual prices against the 12-month rolling average of market costs that would have resulted under competitive market conditions. (See Ref. [6]).
- Locational Market Power Monitoring – Locational market power may arise when system conditions (such as transmission bottlenecks) restrict supply available to meet local demand to a few suppliers. Monitoring and tracking local market power in a preventive manner (prior to closing the market and publishing the market prices) is highly desirable and is practiced by several of the existing ISO's. Re-running the market after the fact, and correcting prices based on mitigated bids due to post-mortem recognition of local market power conditions is cumbersome, dispute-prone and time consuming.

4.3.5. Behavioral Monitoring

Behavioral monitoring involves the collection and analysis of individual bidding and scheduling data in all related markets and comparing the bid quantity and price with past bidding behavior or to marginal cost of providing the service. An application of this type of analysis is provided in [5].

- Monitoring for changes in bidding patterns – Changes in bidding patterns should be monitored in the energy, ancillary services and transmission congestion markets. Excessive changes in bid prices from a given resource from an hour to the next or on different days could signal the need for close scrutiny by the market monitor. Similarly, in a competitive market, the variation of bid price with output level of a resource or a portfolio of resources is expected to be consistent with their corresponding cost of production. The so-called "hockey stick" bid shapes[24] could signal departure from competitive bidding and call for closer scrutiny.
- Demand bidding behavior and the shape of demand bid curves – Demand can shift across markets to follow cheaper supply, as supply shifts across markets to capture captive demand.

In an evolving market place, there is a need to monitor the behavior of market participants to detect attempts to take unfair advantage. There is also a need to have a clear code of conduct, monitor adherence to it, and implement penalties and sanctions against violators to prevent their taking unfair advantage.

Timely computation and tracking of the indicators outlined above (sections 4.2.1) through 4.2.5) forms the basis of the functional design of the Market Monitoring System.

4..4. Market Analysis Tools

The monitoring tools and indicators mentioned above can be complemented by long-term models to enhance the market analysis capability to detect potential future problems and help devise changes in the market rules, operating procedures, and, where applicable, market structure. The long-term models can be broadly classified as follows:

Market simulation tools – These tools can be used to explain past market behavior and detect flaws in market rules or operating procedures based on historical data. They can also be used with forecast data and planning information to analyze future market trends, determine necessary modifications to existing market rules and help in the creation of new rules and procedures to limit the exercise of market power.

Optimization tools – These are used to develop "least cost" operations decisions given supply **and** demand schedules and bids, taking into account various technical operating constraints.

Models of suppliers' bidding strategy - Conventional energy market simulation models utilize marginal cost of generation and do not predict suppliers' bidding strategies of economic

24. This type of price-quantity bid curve is observed in deregulated markets, whereby the supplier bids close to its production cost for the majority of the capacity of a resource, with a steep price rise for the last few MWs. By bidding close to cost for the majority of its capacity, the supplier maintains its opportunity to make money in the face of competition without risking a loss in market share. By bidding high for the last few MWs, although it risks a small loss of market share, it increases the chances of setting a high market clearing price for its entire supply portfolio in the face of potential scarcity.

and physical withholding. More advanced simulation models have been developed to account for various bidding strategies. Some typical bidding strategies based on economic models of oligopoly pricing strategy include the following:

- Cournot Model. In this model, the products are assumed to be homogeneous and demand is assumed to be elastic (price-responsive).
- Bertrand Model. In this model, firms compete through pricing of their products.
- Stackelberg Model. This differs from the Cournot model in that the firms do not choose their outputs simultaneously. The so-called "leader" firm moves first, taking into account the expected reaction of the rival firms (the "followers").
- Supply Function Equilibrium (SFE) Model. In the SFE model, each firm's strategy is to choose a supply schedule or bid function (price vs. quantity). A market-clearing mechanism determines the market price by equating the aggregated bid function to the market demand (which may or may not be elastic).
- General Conjectural Variations Model. In this type of model, each firm i produces a level of output that is profit maximizing, given its conjecture about its rivals.

The Cournot and SFE models are most often used to analyze the impact of market structure such as levels of reserves, long-term contracting, and demand-side programs in the deregulated electricity markets.

4.5.1. Market Monitoring Data Requirements

Effective and efficient monitoring of market performance requires: input from internal systems and operations staff, modeling of complex rules, operating procedures, and knowledge of data definitions, access to confidential trading and operational data, and external data sources (other electricity markets, other energy markets such as the gas market, ownership affiliates, etc.). These are addressed briefly below.

4.5.1. Input from internal systems and operations staff

The market monitoring systems rely on data from various internal systems (bidding, outage scheduling, forward market scheduling, dispatching, metering, and the SCADA/EMS). Often the data from these systems reside in different databases. This may give rise to data inconsistencies. A general practice being followed is to use data warehouse technology to ensure consistent data for market monitoring. Market monitoring also relies on control room operating logs maintained by the operational staff and modeling of complex rules, procedures, and knowledge of data definitions

It is essential to maintain unambiguous up-to-date data definitions as changes and upgrades are made to the ISO/RTO systems.

4.5.2. Confidential trading & operational data

Market data and results are published at different time intervals depending on the nature of the data. Market prices are issued as soon as possible after the close of the market. Bid data are generally published anonymously with a time delay (usually 6 months). However, some data may be confidential and may not be published at all. This type of data is, nevertheless, used (by the ISO and other oversight and investigation bodies) for market monitoring and analysis.

4.5.3. External data sources

The Market Monitoring System also relies on data from other electricity markets in the region, fuel prices, emissions prices, weather data, and hydrological data.

4.6. Illustrative Example: California ISO

In California, deregulated electricity markets have operated since April 1998. In the first two years of operation, markets operated under relatively competitive conditions. A large dislocation occurred in May 2000 when low hydro conditions throughout the western United States caused reserves to fall to 5% and sellers into the market became pivotal in setting prices. There were ineffective market power mitigation measures available to deal with the resulting market power problems. The market was allowed to set very high prices in almost all hours. There was a huge transfer of wealth to suppliers of electricity resulting from their exercise of market power. Wholesale electricity costs in the first two years of market operation averaged approximately $7.7 billion per year. They rose dramatically in year 2000 to $27 billion. The cost in the first six months of 2001 was approximately $20 billion. The total amount above competitive market levels is estimated to be $9 billion for the period.

Exhibit 4 shows the monthly wholesale cost of serving load within the California ISO controlled grid since 1999. It presents the basic information on market volume and prices. The bars show the total monthly consumption and the line depicts the average monthly energy cost in $/MWh.

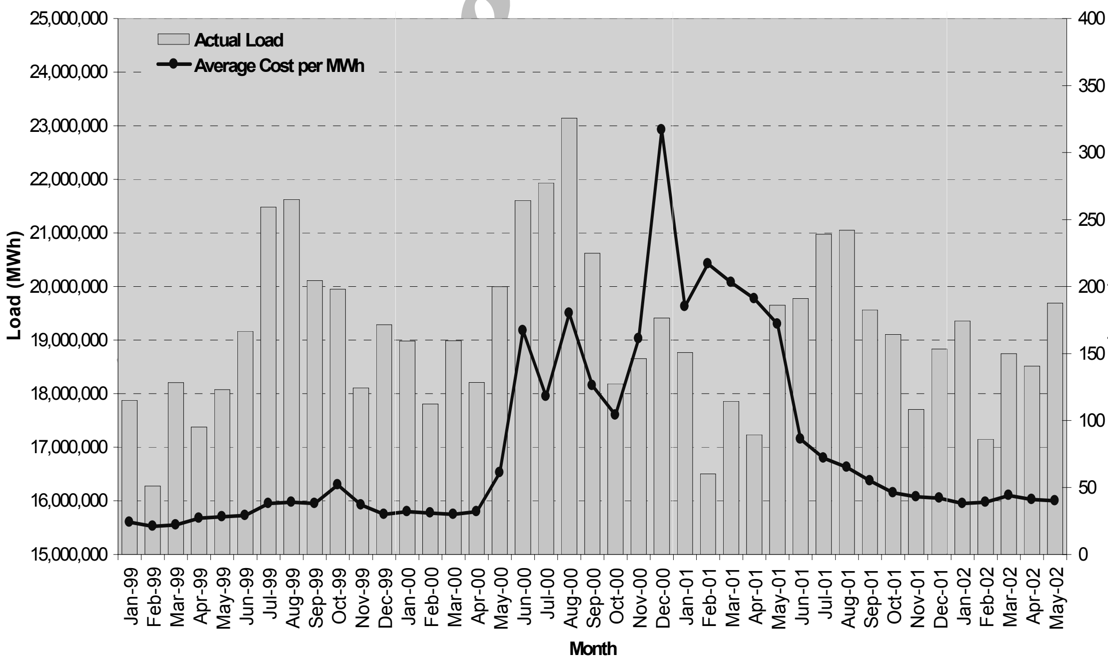

Exhibit 4: Monthly Loads and Average Energy Cost to Serve Load

Exhibit 5 reports a summary of the total monthly cost of the ancillary services market as percentages of total energy cost. It serves as a high level summary of the overall performance of all ancillary services markets.

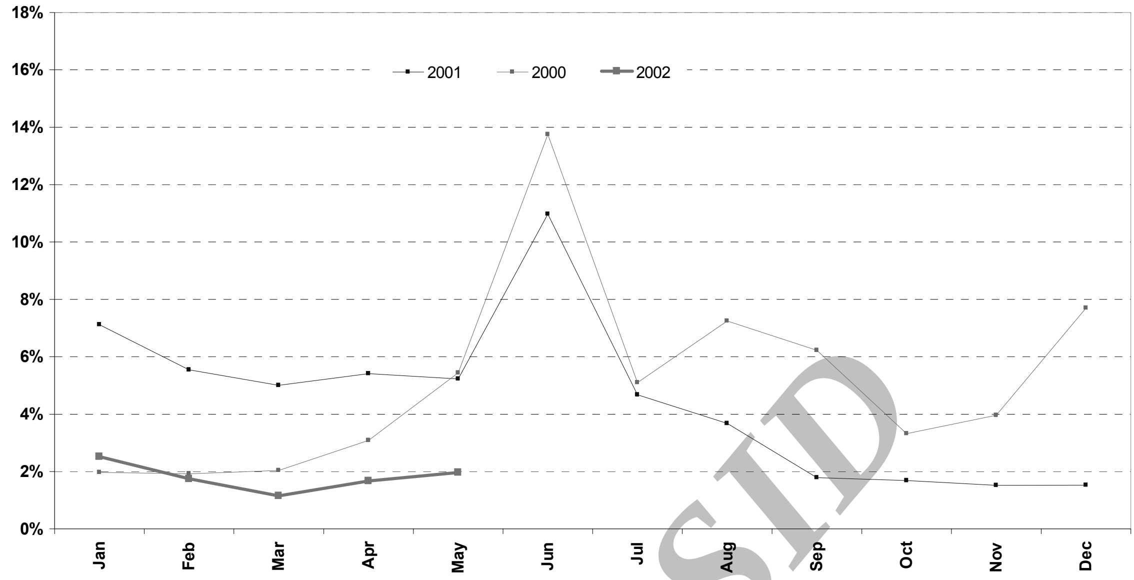

Exhibit 5. Total Ancillary Service Costs as a Percentage of Energy

Exhibit 6 provides an example of a weekly review of supply and demand conditions for the real-time market. Dispatch quantity represented by the line illustrates the demand side of the real-time market. The various price ranges for bids are represented by the stacked bars. The height of each bar segment shows the MW amount of the bids in each price range. This type of summary chart can be done hourly, daily, weekly or monthly.

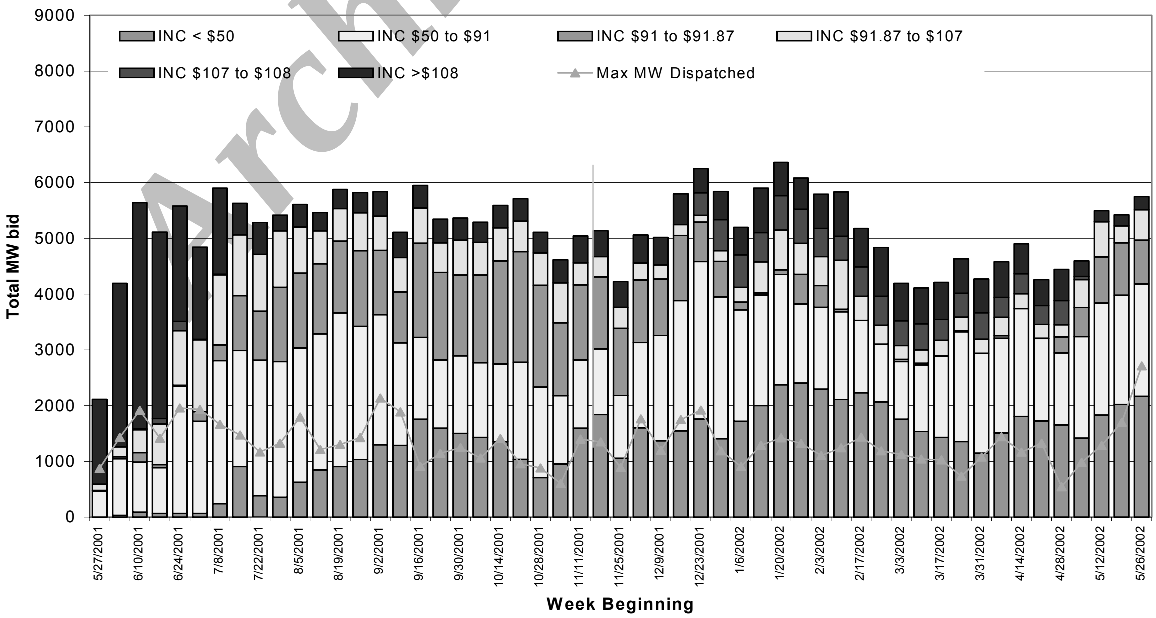

Exhibit 6. Demand and Supply Conditions in Real-time (May 2001 to May 2002)

One of the most important indicators of market competitiveness is the price-cost mark-up index (see Ref. [10] through [13]). This index shows the level at which actual market prices are above an estimated competitive benchmark. Exhibit 7 shows the monthly average price-cost mark-up in the California ISO real-time energy market. This index uses known system supply and demand conditions to estimate the system marginal cost for each hour. The system marginal cost is used here as the competitive benchmark. If the monthly price-cost mark-up is very low, then the market is deemed competitive. If the monthly price-cost mark-up is significantly high, it signals potential market power and we conduct an in-depth analysis of supplier bidding to further investigate the market condition.

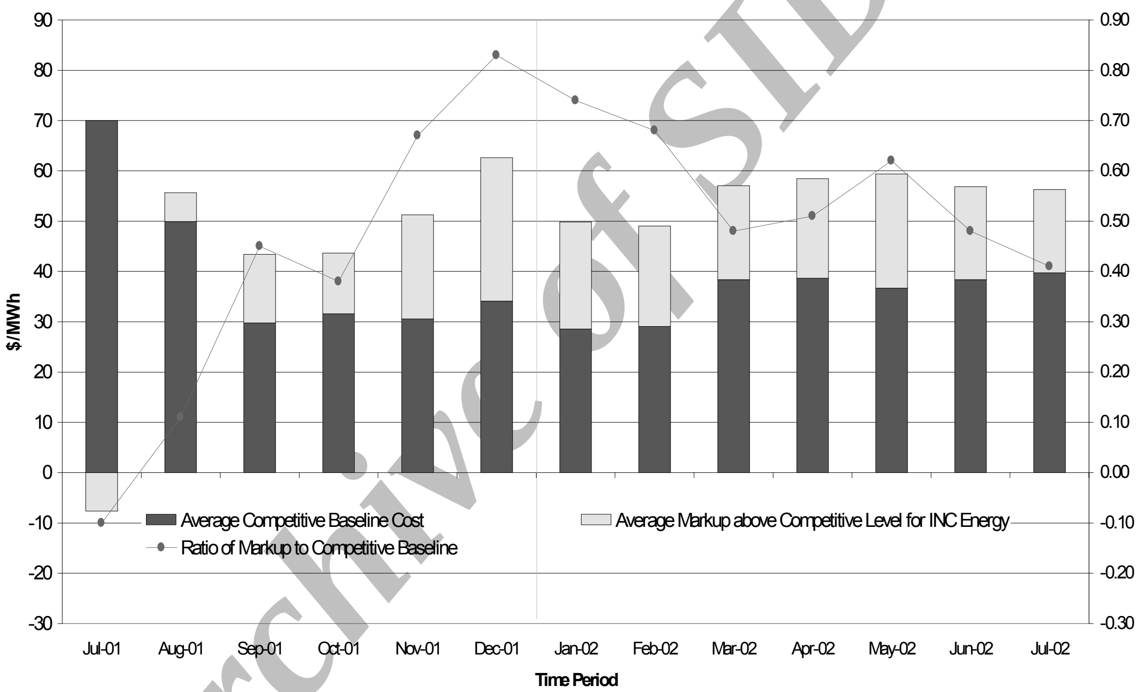

Exhibit 7. Price/Cost AMark-up; Real-time Energy Market (Jan 2001 to May 2002)

Since market power is defined as the ability of suppliers to inflate prices significantly above competitive levels for a sustained period of time, a measure of overall market competitiveness is developed using a cumulative weighted average of price-cost mark-up over a rolling 12-month period. If the market price fluctuation is transitory and moderate, the 12-month index will remain low. Only when the price cost mark-up is long lasting or reaches extremely high levels for a shorter period of time, will the 12-month index cross the threshold.

The 12-month index can be used as the test for just and reasonable rates in deregulated markets, using a reasonable threshold. A threshold in the range of \$5/MWh to \$10/MWh is recommended based on 5 years of experience with the California market. If the threshold is exceeded, pre-approved market power mitigation measures should be imposed until the market is restored to a competitive condition. Exhibit 8 shows, for the first two years of California ISO operation, the market was competitive and the 12-month index remained below $5/MWh. Starting in May of 2000, unusually high prices for many days moved the 12-month index upward. If California ISO were authorized to impose effective pre-approved market power mitigation measures at the time, most of the California energy crisis could have been avoided. The monthly mark-up index dropped to below the threshold in July 2001 and the 12-month index returned to the threshold by June 2002. The return to competitive conditions illustrates that effective market power mitigation measures reined in market power so that a healthy wholesale market could be re-established.

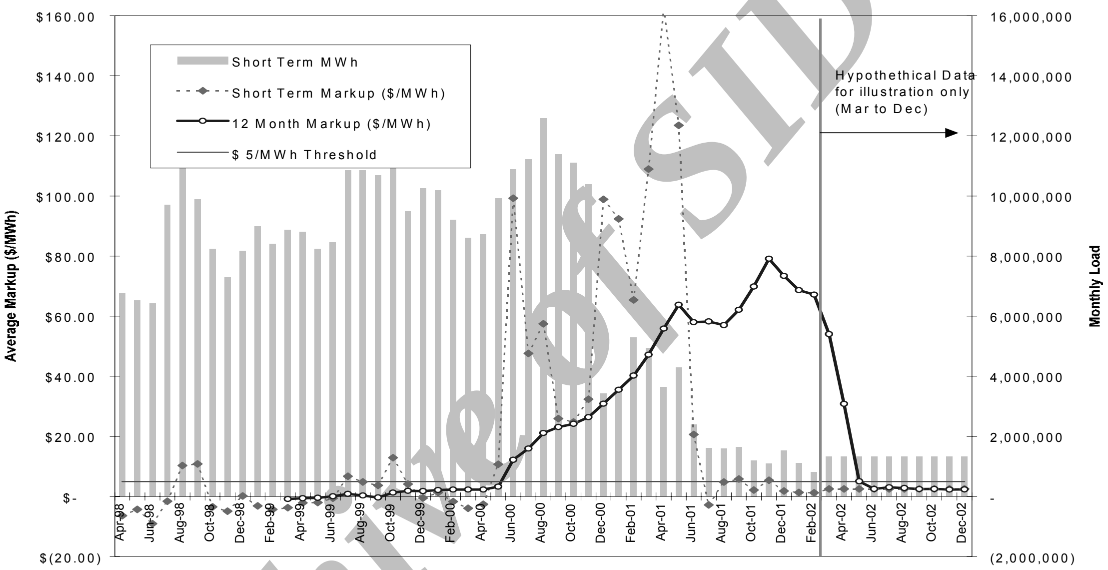

Exhibit 8. The 12-Month Rolling Competitiveness Index (April 1998 to May 2002)

5. Concluding Remarks

The basis premise of the restructuring of the electricity markets has been that competition results in lower costs to the consumers. This expectation is based on the reduced costs to the consumers as a result of deregulation of some other industries such as air travel and telecommunications. The actual experience with deregulation of the electricity industry has thus far yielded mixed results. Seemingly innocuous design elements have sometimes proved to be fatal in practice. Deregulation of the electricity market in California led to excessive costs and the bankruptcy of two of the three Investor Owned Utilities. In PJM, it has been successful, however.

ISO markets hold the promise of being open and competitive and should bring about lower cost to consumers in the long run. These markets, however, due to structural problems and design flaws also increase the potential for market power and gaming. Effective market monitoring at the ISO level and at the level of regulatory agencies is critical in detecting market power and other anomalies and allowing corrective actions to be taken. To perform effective market monitoring, the market monitor needs to develop a comprehensive and sensitive set of monitoring indices and reports that monitor demand and supply conditions and suppliers' bidding behavior. More importantly, the regulatory body needs to establish a clearly defined and measurable standard for just and reasonable rates. With a properly designed market monitoring program and Market Monitoring System (MMS), the market monitor and regulatory agencies can quickly determine whether the market is competitive or not and effective solutions can be implemented to ensure a competitive market outcome.

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Biography

Farrokh A. Rahimi received his Ph.D. in Electrical Engineering from M.I.T. in 1970. He has over 30 years of experience in power systems analysis, operation, planning, and control as an engineer, educator, researcher and consultant. He started his professional career at Systems Control, Palo Alto, California in 1970, and continued as Full Professor of Electrical Engineering at Sharif University, Tehran, Iran, Division Lead at the Electric Power Research Center (MATN), Tehran, Iran, Consultant to the European Economic Commission, Senior Engineer at Brown Boveri, Switzerland, Manager of Energy Department at Systems-Europe Brussels, Belgium, Lead Principal Engineer at Macro Corporations (Subsequently KEMA Consulting), and the founder of OPen Access Consulting (OPAC) established in 1997 with special emphasis on utility restructuring, and design of operations support systems in the restructured environment. He has provided consulting services to electric utilities in many countries in Europe, North America, Latin America, Africa, Asia, and the Middle East. He has carried out several recent studies related to the impacts of utility restructuring, with particular emphasis on operational and planning issues, and related computer based systems and applications. He is currently a consultant to California ISO's Department of Market Analysis. In this capacity he is involved in the analysis of ISO's Ancillary Services, Congestion Management, and Real-time Energy market behavior and rules, development of market monitoring indicators and measures to detect and mitigate potential market gaming, and to improve ISO dispatch and control operation. He is also actively involved in the redesign of the California markets.