Public Utility Commission of Texas

A Primer on Wholesale Market Design

Market Oversight Division White Paper

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A Primer on Wholesale Market Design

Market Oversight Division Staff Report
Eric Schubert, Ph.D. – Team Leader
Sam Zhou, Ph.D.
Tony Grasso
Grace Niu

This white paper is a primer on wholesale market design and provides background for the open meeting workshop scheduled by the Public Utility Commission of Texas for November 1, 2002. The paper is divided into six sections:

1. Reasons for this rulemaking;
2. Measures of an efficient, sustainable market;
3. Architecture of power markets;
4. Elements of a power market;
5. Basic economics of congestion management and day-ahead markets; and
6. Descriptions of wholesale electric markets around the world.

Reasons for this Rulemaking

The Commission opened Project 26376, *Rulemaking Proceeding on Wholesale Market Design Issues in the Electric Reliability Council of Texas*, for the following reasons:

Systematic review

The goal of this rulemaking is to undertake a systematic review of key elements of the ERCOT wholesale market structure. From 1999 to 2001, ERCOT stakeholders developed, and the Commission approved, a wholesale market with a zonal congestion management system that relied on market participants using bilateral forward contracts exclusively, with the system operator running a minimal real-time (RT) balancing market. This approach differs from established wholesale markets in the Northeast such as Pennsylvania-New Jersey-Maryland (PJM), New York and New England and from the standard market design (SMD) proposed by the Federal Energy Regulatory Commission (FERC). Each of these other markets use a nodal congestion management system and an RTO-administered day-ahead energy market. A number of market participants, particularly those who do business outside of Texas, have expressed an interest in developing a wholesale market in ERCOT that is comparable to other wholesale markets in the United States.

Continuity and change

Since the approval of the ERCOT protocols in June 2001, ERCOT stakeholders have been addressing key market design issues on an *ad hoc* basis. Some efforts are a response to the Commission's Order on Rehearing in Docket No. 23220, *Petition of the Electric Reliability Council of Texas for Approval of the ERCOT Protocols*, while others are stakeholder-driven proposals. This piecemeal approach has led to stakeholder frustration and some uncertainty as to where the wholesale market design is headed.

A number of stakeholders have expressed to Market Oversight Division (MOD) that while some change may be inevitable, that they see no need for an immediate, radical change to a market that is functioning. Stakeholders need time to renegotiate the market structure. ERCOT and market participants need to test software and telecommunication systems thoroughly. This rulemaking, which is slated to be a three-year, systematic approach to market redesign, will provide a predictable and coherent path to a redesigned market, giving market participants time to respond and adjust their commercial contracts to any significant changes in market structure.

Address outstanding local congestion and locational pricing issues

In Docket No. 23220, the Commission ordered that the current zonal model include direct assignment of local congestion costs to avoid profiteering through decremental bidding, also known as the DEC game.[1] As MOD has stated in comments previously filed in this project, such a proposal also would provide more accurate locational marginal pricing within the current zonal framework.[2] Most market participants have opposed MOD's proposal, which essentially adds nodal prices to the current congestion management scheme in ERCOT when needed. Some market participants believe that the problems that MOD has raised are not significant and do not require a change in the congestion management system beyond the reduction of out-of-merit energy (OOME) and out-of-merit capacity (OOMC) reimbursement, a change that was implemented on July 31, 2002. Other market participants want to address the DEC game and locational pricing issues by implementing a nodal congestion management system rather than using MOD's proposal.

Consider an ERCOT-administered day-ahead energy market

ERCOT is the only successfully deregulated wholesale market in the United States that relies solely on bilateral forward contracting among market participants. A number of market participants have expressed their frustration at lack of access to the energy market. According to them, the current reliance on bilateral markets is insufficient for their business needs, and a DA

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[1] The DEC game occurs when (1) a market participant submits schedules in forward markets that if followed would create local congestion, (2) the market participant is paid in the real-time market to "solve" the anticipated congestion by generating less than what was scheduled, and (3) the cost of these local congestion payments are uplifted to load. If participants are not charged for creating congestion when they schedule too much flow over a constrained local line, then they have an incentive in the real-time market to collect payments to alleviate this local congestion by decrementing their flows on this congested local line. The DEC game can be prevented by making market participants pay congestion fees for use of the congested local line.

[2] Project No. 26376, *Rulemaking Proceeding on Wholesale Market Design Issues in the Electric Reliability Council of Texas*, "Initial Comments by the Market Oversight Division," September 6, 2002.

energy market based on centralized exchange – with a third party intermediary for all trades – would make them more competitive and profitable. ERCOT is instituting a relaxed balanced schedule, which would allow for more trading in the real-time market for balancing energy. This rulemaking will examine whether ERCOT should operate a DA energy market or contract with a private entity that would operate one.

Develop a sustainable market structure

ERCOT stakeholders developed the current wholesale market design under the pressure of a legislative mandate and deadline. They were largely successful in creating a well-functioning market. However, the Commission has identified some chronic problems and inefficiencies in the wholesale market design that may worsen over time if not corrected, and has ordered ERCOT to change the protocols. In response to the Commission's orders, ERCOT stakeholders have changed the market structure in ways that have reduced the scope of the problems but are not fully consistent with the Commission's orders. While these efforts by stakeholders to address the Commission concerns are recognized and appreciated, MOD believes that stakeholder solutions, which usually reflect certain compromises, have not been benchmarked against fundamental economic principles and fail to institutionalize incentives that are compatible with the overall market structure.

MOD believes that this rulemaking will give the Commissioners, working with ERCOT stakeholders, a chance to update and improve certain aspects of the ERCOT market. This proceeding will allow the Commissioners to make essential decisions on tough policy issues that are not suited to stakeholder compromise. The rulemaking will give all stakeholders a chance to discuss their concerns about proposed changes to the market structure, with the Commission ultimately ruling on the required market features in sufficient detail to avoid rancorous and unproductive debate at ERCOT. Implementing a wholesale market design in the context of a rule protects the market structure against future changes proposed in haste to address short-term problems while allowing the market structure to be readily amended when experience in ERCOT or other markets indicates a need for modest change. The projected three-year rulemaking process can build a market with a solid foundation from redesign up to implementation, while allowing ERCOT stakeholders to develop the commercial and operational details in the implementation.

FERC SMD

FERC has initiated a rulemaking to develop a standard market design (SMD) that is creating a debate across the country on what the appropriate wholesale market structure should be . ERCOT is ahead of the curve on many things compared to the FERC SMD and is running parallel on others. Market players who also are involved in a number of other wholesale markets as well as MOD would like to address these issues at ERCOT at the same time FERC is considering them.

Measures of an Efficient, Sustainable Market

MOD proposes that the Commissioners and stakeholders keep the following questions and concerns in mind when debating and deciding key market design issues. These points are based on widely accepted market design principles that would promote an efficient, sustainable wholesale market in ERCOT.

Economic Efficiency

- Are scarce resources, such as transmission and generation capacity, allocated to those parties that are most willing to pay for them?
- Does the market structure encourage resource owners to submit their resources at marginal cost?
- Does the market structure discourage resource owners from withholding their resources?
- Do prices in the market send signals that will encourage the appropriate scheduling of power?
- Do prices in the market send signals that will encourage the appropriate amount of new transmission?
- Do prices in the market send signals that will encourage the appropriate siting of new transmission and generation?
- Do parties have the ability to enter into bilateral contracts that reflect their preferences for fuel type, price, length of contract, and contract counterparty?
- Do parties have the ability to buy and sell in the short-term (day-ahead or hour ahead) to allow them to adjust to unexpected changes in supply and demand at a given location?
- Do the parties have the ability to choose the proper mix of wholesale services obtained via a private market and those obtained via the system operator?
- Does the market structure assist the development of innovative new products such as demand-side responsiveness, wind power, and distributed generation resources?
- Does the market have a sufficient array of contractual alternatives so that market participants can maximize the value of their assets?
- Does the market provide participants with adequate risk management tools?

Price discovery

- Are energy and transmission prices transparent?
- Do the various markets in ERCOT provide sufficient liquidity?
- Does the ERCOT wholesale market send the proper type of price signals for the following:
    - Location?
    - Transmission?
    - Generation?
    - Forward contacting?

    - Real-time transactions?
- Do electricity users have adequate opportunities to adjust their consumption in response to fluctuations in prices?
- Is the market sufficiently transparent to allow monitoring and detection of market power abuse?

Equity among market participants

- Would a change in market structure improve the ability of certain market participants to buy or sell power in the wholesale market?
- Do parties have a reasonably wide range of choices to meet their obligations (i.e., self-arrangement, bilateral contracts, ERCOT-procured)?
- Would the features of a market that ERCOT would run provide value to end users of electricity sufficient to justify the expense?
- Are the market rules designed in a non-discriminatory way to create level playing field for conventional and non-conventional resources?

Subsidizing and uplifting of costs

- Do the market rules eliminate uplifting of costs or, at least, make the uplift so small as to deter market participants from gaming the market?
- Do the market rules subsidize market participants in a way that is not sanctioned by explicit Commission or Legislative policy?

Gaming opportunities

- Are market rules properly designed to include economic incentives and disincentives to encourage compliance with the rules?
- Are the features of the market designed to effectively discourage the exercise of market power?
- Are the rules of the market incentive compatible (i.e., do they induce market participants to bid their true costs and preferences)?

Impact on reliability

- Does any element or combination of elements of market design significantly reduce the reliability of the grid?

Architecture of Power Markets

The main challenge of designing a wholesale electricity market is how to combine the real-time market for transactions coordinated by a system operator with forward markets comprising long-term bilateral contracts between power generation companies (PGCs), retail electric providers (REPs), non-opt-in entities (NOIEs), power marketers, and aggregators. What institutions will blend these markets so as to provide end-use customers with the widest range of choices and the best value?

The Real-Time Market: Realm of the System Operator

The delivery of electricity has physical characteristics that make its wholesale market structure unique. Storage of electricity is very expensive and not considered cost-effective in most situations. Transmission lines are congested, generators have limits on the speed in which they can ramp up or down, and all but the largest loads are price-inelastic in the short-run.[3] The transmission grid is highly complex and vulnerable to instability. The maximum cushion available to operators to maintain system stability is the ten minutes in which governors and automatic controls on generators can compensate for energy imbalances in the system.[4]

The system operator is concerned with strengthening the physical functioning and ensuring the coordination of all aspects of energy, transmission and reserves. The chief economic consequence of the need to maintain the stability of a complex electric grid is that the real-time market for electricity is driven by the physical realities of the grid rather than the financial transactions of the market participants. Because of the unique characteristics of electricity, there can be only one spot market for energy, the real-time "balancing market" conducted continuously by the system operator as an integral part of its management of grid.[5]

The system operator also tends to be concerned with operational efficiency of the grid, where in real time the cheapest combination of units is deployed. This approach is consistent with the dispatch of resources in a control area in the pre-SB 7 world, where retail customers had no choices in the type of electric service they received. The electric provider chose the types of generation (i.e., coal, nuclear, gas-fired), set the price for the customer under tariffs the Commission approved, and attempted to dispatch the units as efficiently as possible in real-time.

Forward Market: Realm of the Marketer

The ERCOT stakeholders, when designing the ERCOT wholesale market, used forward bilateral contracts as the basis for the energy market. Marketers favor such a design because they believe that market participants should have the widest range of choices to meet the needs of their customers. For instance, in the ERCOT market qualified scheduling entities (QSEs) can meet their ancillary service requirements through self-provision, purchase through bilateral contracts, and to purchase through a voluntary ERCOT-run day-ahead capacity market. This principle will continue to be a cornerstone of any market rules that the Commission develops.

A key feature of SB 7 was the separation of generation, retail marketing, and transmission. The unbundling allows market participants to choose from dozens of REPs and PGCs. The REPs and PGCs have the ability to offer a wider range of fuel sources and costs, including cutting edge technologies such as renewable resources, demand-side products, and distributed generation.

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[3] Robert Wilson, "Architecture of Power Markets," Graduate School of Business, Stanford University, Research Paper Series No. 1708, September 2001, page 3.

[4] Wilson, "Architecture of Power Markets," page 4.

[5] Wilson, "Architecture of Power Markets," page 5.

Marketing efficiency might be defined as most accurately reflecting the preferences of market participants such as QSEs, PGCs, REPs, and NOIEs. Market participants have different tolerances for risk, different approaches to meet the needs of their customers, and different planning horizons. The private market that developed as part of SB 7 organizes transactions based on concerns other than real-time efficiency that predominated the market before deregulation.

Architecture of Power Markets: Linking the System Operator and the Marketer

The tradeoff in designing the ERCOT wholesale market is between tighter coordination of resources (the concern of the system operator) and the wide variety of bilateral energy contracts (the concern of the marketer). Deploying balancing energy and ancillary services as well as transmission pricing are all done in real-time. Bilateral contracts are signed days, months, or years ahead of real-time and aren't written in enough detail to handle the continually changing real-time status of the grid. The wholesale market must try to link the bilateral, unbundled market that provides the greatest range of competition and innovation in products and services (marketing efficiency) with the necessary centralization of the real time market (engineering efficiency).

Put another way, reliance on private market structures often reduces system operator discretion. In the ERCOT wholesale market, this trade-off reflects the unbundling of energy, transmission, reserve capacity, and retail marketing into separately priced services, and reflects the need to coordinate these unbundled pieces of the market both in the long-run and in real-time.[6] According to Wilson, however, this tradeoff is not intrinsic: highly evolved markets with elaborate pricing could be sufficient to achieve perfect coordination.[7]

Elements of a Power Market

After listening to stakeholders' oral comments at the September 6, 2002 workshop in Project 26330, *Lessons Learned: Evaluation of the Performance of the ERCOT Wholesale Market*, and reading stakeholders' written comments filed on the same day in Project 26376, *Rulemaking Proceeding on Wholesale Market Design Issues in the Electric Reliability Council of Texas*, MOD determined that a number of stakeholders, including MOD, needed to better understand the various elements of a wholesale electricity market.[8]

This section will describe a number of key elements that need to be considered in developing a sustainable wholesale market design. Table 1 lists a number of different market design elements that the Commission and ERCOT have addressed or are addressing. After reviewing these market elements, MOD has come to the following conclusions:

1. Not all elements need to be considered in this rulemaking project,

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[6] Wilson, "Architecture of Power Markets," page 5

[7] Wilson, "Architecture of Power Markets," page 6.

[8] On September 6, 2002, Project 26376 was not a formal rulemaking and was known as *Transmission Issues in the Electric Reliability Council of Texas*. All filings made under the project number are considered filings in the rulemaking proceeding.

2. The congestion management system that a wholesale market uses, whether it is a zonal model or a nodal model, is the fundamental market design choice that needs to be made. All other market features can work within a zonal or nodal framework.

Table 1:
Comparison of Nodal (LMP) and Zonal Market Designs

	Market Design Element	*Specific to Market Design?*
1	Congestion management mechanism	Fundamental market-design specific feature
2	Treatment of pre-assigned Transmission Congestion Rights (PCRs) and grandfather FTRs (or CRRs)	It is not specific to a particular market design. Both Zonal and Nodal have to deal with this element. There may be less uplift due to the fact that the majority of TCRs is auctioned.
3	Central dispatch	It is not specific to a particular market design. Both zonal and Nodal model could require central dispatch.
4	Treatment of bilateral contract in central dispatch	It is not specific to a particular market design. Both zonal and Nodal model could require bilateral contracts go through central dispatch. In ERCOT, less than 3% to 5% of bilateral contracts may go through central dispatch. These figure are 20% to 40% for PJM and 100% for NYISO, respectively.
5	Portfolio vs. unit-specific resource plan	While ERCOT has portfolio resource plan, unit specific resource plan could also be implemented under Zonal market design.
6	Day-ahead energy and capacity markets	It is not specific to a particular market design. Both zonal and Nodal model could require day-ahead energy and capacity markets.
7	Real-time energy market	It is not specific to a particular market design. Both zonal and Nodal model could require same-day spot energy market.
8	Mechanism to mitigation market power	It is not specific to a particular market design. Market power mitigation procedures are required for both Zonal and Nodal market designs.
9	Load resources participation	It is not specific to a particular market design. While ERCOT has good features to enhance load participation, more accurate price signal in Nodal design may turn to be more effective for load participation.
10	Balanced scheduled requirement and allowable Schedule Control Errors (SCEs)	It is not specific to a particular market design. ERCOT is working of a PRR to require binding resource plans. A new penalty mechanism could encourage more resource accuracy. Dynamic scheduling can reduce this problem.
11	Ancillary services procurement and responsibilities	It is not specific to a particular market design. Both zonal and Nodal model could have mechanism to adequately address this issue.
12	Generation adequacy and reserve margin	It is not specific to a particular market design. Both zonal and Nodal model could have mechanism to adequately address this issue.
13	Data and market information transparency	Nodal will provide more transparent price information.
14	Economic efficiency (Don't let the perfect be the enemy of the good enough)	The implementation of any congestion management model has imperfections, so the current versions of the nodal and zonal models throughout the world are "second best" expressions of the model's ideal state. MOD has not seen empirical study that demonstrates which of these two "second bests" is superior with respect to economic efficiency.

Discussion on the Market Design Elements

Congestion Management Mechanism

A zonal model makes a number of simplifying assumptions. When the system operator manages congestion and assigns locational prices in a wholesale electric market, not all transmission lines are considered equal. The model assumes that a number of commercially significant constraints (**CSCs**, also known as flowgates) are consistently and persistently limiting export or import. Congestion that occurs across a CSC is called **zonal congestion**. The model directly assigns congestion fees for these CSCs and sells financial transmission rights that allow market participants to hedge the cost of moving power across CSCs. The CSCs define zones that will have different RT balancing energy prices when at least one of the CSCs experiences congestion. In 2002, ERCOT has four CSCs that define four zones, and can have four distinctive zonal prices.

Congestion does not occur solely across CSCs. Congestion on lines within a zone is called **local congestion**. If CSCs are properly defined, the causes of zonal congestion differ from the causes of local congestion. Zonal congestion will occur regularly, even if the system operator directly assigns congestion fees. An example would be the STP-Dow transmission line that separates the South Zone from the Houston Zone in ERCOT. Local congestion occurs sporadically and randomly, often when a resource or transmission line is out of service for a period of time.

Clearing congestion in the ERCOT zonal model is a two-step process. First, the system operator determines which resources to deploy to relieve zonal congestion. After making that determination, ERCOT takes a second step by changing its planned deployment of resources within a zone to relieve local congestion while maintaining the total level of energy deployed within a zone.

Under the ERCOT protocols, local congestion costs are uplifted on a load-ratio share basis. On March 5, 2002, these costs crossed the $20 million threshold that was established in the Order on Rehearing in Docket 23220, *Petition of the Electric Reliability Council of Texas for Approval of the ERCOT Protocols*. A proposal by MOD to implement direct assignment of local congestion fees, as ordered in that docket, is under consideration in this rulemaking. ERCOT stakeholders approved an interim step on July 31, 2002 that could reduce the size of the local congestion costs going forward, but it did not eliminate the potential for gaming local congestion.

To run a nodal model, the system operator needs to know the output level and bid price of each level of output of each resource in the system for each settlement interval as well as the location of each load that the resource is serving. The output level is needed to allow the simultaneous feasibility test (SFT) software to calculate the impact of the resource's output on each transmission line. The bid for each output level is necessary for the system operator to determine the cost of clearing one MW of congestion (shadow price) on each constrained line and to deploy those units that are centrally dispatched within the system.[9] Therefore, the QSE needs to submit a unit-specific bid curve, not just a premium bid as is done under the ERCOT protocols.

[9] Under a nodal system, QSEs do not have all their output available for central dispatch. For instance, a nuclear power plant under contract would reject decremental instructions except in emergency situations (when the market has broken down by definition). When a QSE submits a scheduled transaction between the nuclear power plant (source) and the load its serves (sink) without a bid curve, the system operator infers that QSE has submitted

In the past year, ERCOT stakeholders have discussed two alternatives in congestion management that would provide ERCOT with a sustainable market design: the current zonal model supplemented by MOD's proposal to directly assign local congestion fees and a nodal system.[10] The current ERCOT zonal model uplifts local congestion costs, provides incentives for gaming local congestion costs (and the incentives increase proportionately with increases in zonal MCPEs) and does not provide locational pricing within a zone. The changes ERCOT stakeholders made in July 2002 have reduced the need for immediate implementation of MOD's proposal and can be considered an interim step in meeting the requirements of Docket 23220 until the Commission resolves the issue of congestion management in this proceeding in the first quarter of 2003.

If the Commission decides to implement a nodal congestion management system by 2006, then for the interim the Commission has a choice between the current zonal model with uplift of local congestion costs or MOD's proposal to directly assign local congestion costs. The Commission will base this choice on the relative costs, benefits, and risks of each approach.

Treatment of Pre-Assigned Congestion Rights

Congestion rights under the current zonal model are flowgate rights, that is, financial rights across a specific transmission line or set of transmission lines. Under a nodal model, congestion rights can be flowgate rights, point-to-point rights, or a combination of both. A point-to-point right is a hedge from the source (i.e., where the power is injected, such as a combined cycle plant in the Valley) and the sink (i.e., where the power is withdrawn by load, such as an industrial customer in Corpus Christi). The hedge is not a specific path between the source and sink, because as is discussed in a section below, power flows follow the path of least resistance and are influenced by the topology of the grid and the pattern of injections and withdrawals at any given moment.

As listed in Table 1, both nodal and zonal models can accommodate pre-assigned congestion rights. Under a nodal system, the Commission will need to determine that whether any pre-assigned congestion rights it has granted NOIEs should be flowgate rights or point-to-point rights and price them accordingly.

Central Dispatch

Both zonal and nodal systems rely on central dispatch for some of the energy provided in the wholesale market. Under the current zonal model in ERCOT, the ERCOT system operator controls the output level of resources that provide ancillary services and balancing energy by sending centralized dispatch instructions. As part of the optimization routine embedded in ERCOT operational software, the system operator potentially will redispatch any resource that has an outstanding balancing energy bid that can improve economic efficiency (e.g., DEC an

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decremental bids with a price of negative infinity. A QSE, however, would have to submit enough incremental and decremental bids to allow the system operator to clear congestion and maintain reliability.

[10] For more on MOD's proposal to directly assign local congestion fees, see MOD's August 27, 2002 filings in this proceeding. On August 27, 2002, AEP and LCRA, made filings on the cost of implementing MOD's proposal and a nodal system for their QSEs, AEP made a filing on the cost to ERCOT of implementing a nodal system, and ERCOT staff made a filing on the cost to ERCOT of implementing MOD's proposal.

expensive resource and INC a cheaper resource), even if the resource is not needed to clear congestion or provide an ancillary service. ERCOT also gives unit-specific OOME instructions to manage local congestion and voltage problems.

Treatment of Bilateral Contracts in Central Dispatch

Treatment of bilateral contracts in central dispatch is not specific to a particular market design. Under the current zonal model, the ERCOT protocols require that QSEs provide schedules and resource plans to the system operator, but the QSEs do not provide ERCOT the ability to centrally-dispatch resources associated with bilateral contracts as part of a system-wide optimization of resources. A zonal model, in theory, could require that QSEs have all their resources that are online available for central dispatch by the system operator. That would effectively require all spinning generation to be bid into the balancing market as DEC capacity, and all available unused capacity to be bid as INC capacity.

Under a nodal system, the system operator could require QSEs to submit all resources to the system operator for central dispatch as part of an optimization routine (as is done in the NYISO) or make such a submission optional (as is done in PJM).

Portfolio vs. Resource-Specific Resource Plan

The ERCOT zonal model allows QSEs to provide the system operator with a portfolio resource plan, giving the QSE flexibility in dispatching its resources in the market. The ERCOT system operator could require a resource-specific resource plan in the future within the context of an ERCOT zonal model to improve the operational efficiency of dispatch when using the current two-step method to clear congestion. A nodal model requires a resource-specific resource plan in order for the system operator to price each transmission line and node.

Day-Ahead Energy and Capacity Markets

Day-ahead energy and capacity markets are not specific to a particular market design. ERCOT currently operates a voluntary day-ahead capacity market for ancillary services in its role as provider of last resort for ancillary services. ERCOT could operate a day-ahead energy market within a zonal model and not even need to centrally-dispatch the energy that is committed in the ERCOT-procured day-ahead market.[11]

Designing a day-ahead market has a wide spectrum of options. It can be a simple energy-only market relying on self-commitment. Or it can be a fully centralized unit commitment optimization based on offers specifying economic and technical parameters for each resource (energy bids, start up and no load costs, ramp rates, minimum output, minimum and maximum down times, etc.). Such unit commitment can allow physical bilateral schedules as is done in PJM or require that all schedules including the bilateral ones be subject to redispatch as is done at the NYISO. The unit commitment may be voluntary or mandatory and may be applied to all scheduled energy or just to the net short positions (as is proposed in the California MD02 proposal). The unit commitment may include scheduling of energy only or combine energy and

[11] The QSEs could submit updated schedule and resource plans to the system operator that reflect the results of the auction in a day-ahead energy market.

ancillary service scheduling. The day-ahead market may or may not account for transmission constraints and it may or may not allow virtual bidding. There is also the question of whether the congestion settlement for bilateral transactions and transmission rights should be based on the day ahead nodal prices or on *ex post* real time locational prices.

Real-Time Energy Market

The real-time energy market is not specific to a particular market design. As mentioned above, the real-time energy market is in reality a physical market that the system operator must run.

Mechanism to Mitigate Market Power

The potential for market power abuse exists in both nodal and zonal models, though the potential impact of market power abuse may take a different form in a zonal model than it does in the nodal model. Both market designs would require mechanisms to mitigate market power.[12]

Load Resources Participation

Load resource participation is not specific to a given market design. The current ERCOT model has been successful in providing the means for load resources to participate in the ancillary services markets and balancing energy markets. The current ERCOT model does not provide sufficient granularity in locational pricing to encourage load resources to provide bids to help the system operator resolve local congestion. A nodal model or a zonal model using MOD's proposal to assign local congestion costs could encourage load resources to actively participate in resolving local congestion in the future.

Balanced Schedule Requirement / Schedule Control Errors (SCEs)

This issue is not related to specific market design. ERCOT is working on a PRR to require binding resource plans. A new penalty mechanism could encourage more resource plan accuracy. Wider use of dynamic scheduling could reduce this problem.

Ancillary Services Procurements and Responsibilities

Ancillary services procurements and responsibilities are not specific to a particular market design. Experience has shown that the system operator can acquire the appropriate amounts and types of ancillary services in both a zonal and nodal model.

Generation Adequacy and Reserve Margins

The need to ensure generation adequacy and reserve margins is not affected by a particular wholesale market design. In either market structure, the pressures of retail competition will create an incentive for retail electric providers to secure just enough capacity to meet their short-term needs. As a result, the Commission will need to create a market-based mechanism to help REPs and NOIEs meet a generation adequacy requirement to ensure sufficient supply to

[12] MOD notes that LCRA's Zonal-ERCOT-Nodal (ZEN) model incorporates market power mitigation features in a nodal market structure.

maintain reliability and reduce "boom and bust" cycles in investment of generating capacity. MOD believes that Project 24255, *Rulemaking Concerning Planning Reserve Margin Requirements* is the proper forum to address this issue.

Data and Market Information Transparency

A nodal system will provide more transparent locational energy prices but additional flowgate pricing information is needed to provide transparent pricing for transmission investment because flowgate pricing presents the market with the value of relieving congestion on a set of physical lines rather than prices that result from a system-wide redispatch.

Economic Efficiency (Implementation of the Theoretical Model)

The implementation of any congestion management model has imperfections, so the current versions of the nodal and zonal models throughout the world are "second best" expressions of the models' ideal state. Data provided to a system operator on the output of generating units, voltage levels, and status of transmission lines is not 100 percent accurate in every interval. Manual "workarounds" are a feature of every wholesale market. In certain nodal markets, resources do not respond to all prices that the system operator generates to encourage optimal dispatch in real time. On occasion, ERCOT has given OOME instructions to address zonal congestion.

The ERCOT and PJM markets, though based on different premises, both work. MOD has not seen any empirical study that demonstrates which of these two "second best" implementations is superior with respect to economic efficiency. Whatever market design elements the Commission chooses, the choices should reflect the tradeoffs and imperfections inherent in any functioning market, not a comparison of a working zonal market with an idealized nodal market.

Basic Economics of Congestion Management and Day-Ahead Markets

This section is based on Chapters 3 and 5 of the book Power System Economics – Designing Markets for Electricity by Dr. Steven Stoft and is used with permission of the author. This section of the white paper highlights the consensus among leading experts in electricity economics on the basic economic principles of electricity markets with respect to locational pricing, congestion management, day-ahead markets, and real-time markets. MOD has chosen this text to include in the white paper because as Dr. Stoft states in the Preface of his book:

> *My original purpose in writing this book was to collect and present the basic economics and engineering used to design power markets. My hope was to dispel myths and provide a coherent foundation for policy discussions and market design….*

Though in the book Dr. Stoft states his preferred market design with respect to congestion management and day-ahead markets, his choices are a subset of a larger range of possible choices for the ERCOT market that would be consistent with the basic economic principles detailed below.

Forward vs. Real-Time Markets

Trading for the power delivered in any particular minute begins years in advance and continues until real time, the actual time at which the power flows out of a generator and into a load. This is accomplished by a sequence of overlapping markets, the earliest of which are forward markets that trade nonstandard, long-term **forward contracts**. **Futures contracts** are standardized, exchange-trade, forward contracts. Electricity futures typically cover a month of power delivered during on-peak hours and are sold up to a year or two in advance. Most informal forward trading stops about one-day prior to real time. At that point, in a number of RTOs, the system operator holds its day-ahead (DA) market for energy and capacity.[13] This is sometimes followed by an hour-ahead market and a real-time (RT) market that the system operator also conducts. All of these markets except the RT market will be classified as **forward markets**.

All markets except the RT market are financial markets in the sense that delivery of power is optional, and the seller's only real obligation is financial. If power is not delivered, the supplier must purchase replacement power or pay liquidated damages. In many forward markets, including many DA markets, traders need not own a generator to sell power. The RT market is a physical market, as all trades correspond to power flows. While the term **spot market** is often used to include the DA and hour-ahead markets, this white paper will use it to refer to the **RT market**. A customer who buys power in a forward market will receive either electricity delivered by the seller or financial compensation. This financial compensation is called liquated damages, meaning the damage to the customer has been expressed as a liquid financial sum. This cost defines liquidated damages.

Because customers are virtually never disconnected when the forward contract falls through, power is often delivered in the RT market. Any power that is sold in the DA market but not delivered in real time is deemed to have been purchased in real time at the spot price of energy. This arrangement is called a two-settlement system and has a number of useful economic properties.

Two-Settlement System: Day-Ahead and Real-Time Markets

The RT price always differs from the DA price. Which is in control? In a competitive market the RT prices are true marginal cost prices at a particular snapshot in time, and forward prices are estimates or predictions of future RT prices or are a bundling or averaging a series of projected RT prices for the length of the contract. Forward contracts often include an implicit risk premium because parties that arrange a long-term forward contract cannot know the real-time conditions of the grid for each settlement interval for the life of the contract.[14] The RT market reflects the operational realities and related prices of generation and transmission.

Contracts for differences (CFDs) insulate bilateral trades from all risks of spot price fluctuations while allowing the inevitable inefficiencies of forward trading to be corrected by RT price signals. A CFD requires the load to pay the generator the difference between the contract price

[13] MOD notes that the ERCOT market has functioned well without a formal DA market, and that nothing prevents a private entity from operating a successful centralized DA market.

[14] Although the original text of Stoft's book does not mention a risk premium, MOD spoke with the author to confirm that he did not mention risk in order to simplify his presentation.

and the spot price whether it is positive or negative. Both the two-settlement system and CFDs allow efficient re-contracting – a standard economic solution to problems of decentralized forward trading.

If a generator sells its output in the DA market, the two-settlement system lets it respond efficiently to the spot price without any risk from the volatility of that price. The generator can only profit from an unexpected spot price, and never suffer a loss. If a generator sells its power to a load in a bilateral contract months in advance, a CFD will let them profit efficiently from an unexpected spot price. If they trade over lines that may be congested, purchasing a congestion revenue right (CRR) will provide the same guarantee with respect to transmission prices.

If the system operator runs a DA and a RT market, generators should be paid for power sold in the DA market at the DA price, regardless of whether or not they produce the power. In addition, any RT deviation from the quantity sold in the DA should receive the RT price.

A two-settlement system preserves real-time incentives. When the RT market is settled by pricing deviations from forward contracts at the RT price, suppliers and customers each have the same performance incentives in real time as if they had traded all their power in the RT market.[15] Differences in prices between source and sink reflect the real-time transmission constraints.

Contracts for differences preserve real-time incentives. Bilateral traders using contracts for differences feel the full incentive of RT prices. Because they could ignore this incentive, any deviation from their contract can only be profitable.

Congestion Management and Locational Pricing

The key properties of these prices are that (1) they are competitive prices, (2) the locational energy-price difference is the price (opportunity cost) of transmission, and (3) a single congested line makes the price of energy different at every location. Because they are competitive prices, any perfectly competitive market will determine the same locational prices.

Energy prices differ by location for the simple reason that energy is cheaper to produce in some locations and transportation (transmission) is limited. A transmission line becomes congested when the flow over a line reaches a thermal or stability limit. Congestion keeps energy prices different in different locations.

Supply and demand determine locational prices and have nothing to do with the architecture of the market, provided that it is a competitive market. A purely bilateral market that is perfectly competitive will trade power at the same locational prices as a perfectly competitive, centralized nodal-pricing market. Of course, a bilateral market is likely to be less precise with its pricing, but on average it should find the full set of competitive nodal prices.

Because there is a unique set of locational prices, there is also a unique set of "congestion" prices, also called transmission prices. Again, these are determined by competition and supply and demand conditions. They have nothing to do with market architecture, provided that the market is perfectly competitive.

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[15] MOD notes that this condition is true only for price takers. The incentive of a generator to exercise market power depends on how much is traded in the spot market.

If the competitive energy price at X is $20/MWh and at Y is $30/MWh, the "no arbitrage price" of transmission from X to Y is $10/MWh. Transmission prices are always equal to the difference between the corresponding locational energy prices. If this were not true, it would pay to buy energy at one location and ship it to the other. In that case arbitrage would change energy prices until this simple relationship held.

Ideally, central computation finds the optimal dispatch and then computes prices from the marginal benefits of a free megawatt at each location. Transmission constraints make power more valuable in some locations than others. Arbitrage produces a single price at each location, but transmission constraints can prevent it from leveling prices between locations.

The cost of transmitting power from X to Y does not depend on the path chosen. This result is not surprising, although contracts may stipulate a "contract path" for power, there is no way to influence the actual path taken. Locational prices reflect this reality by making sure that $P_{XZ} + P_{ZY} = P_{XY}$ for any intermediate point Z.

Not only is it impossible to select the path of a power flow, power takes every possible path between two points, with more flowing on the easier routes. The consequence for a network with a single congested line is that every location has a unique price. In effect there is a price for using the congested line, and every transaction uses that line to one extent or another. Sending power from X to fifty different locations will use fifty different amounts of the congested line, so there will be fifty different transmission prices and fifty different energy prices (plus the energy price at X). One congested line in PJM produces 2000 different locational prices. A centralized, real-time market will compute these so accurately that the true locational differences become visible.

Congestion charges are based entirely on scarcity. Congestion charges are typically zero because there is plenty of transmission capacity most of the time. When transmission capacity is scarce, competition for transmission can raise its price steeply. To some extent these prices are predictable, but they contain a significant random component that can be problematic for traders. The uncertainty in congestion price can be hedged by buying energy forwards or options contracts in the two locations or buying transmission rights between the two locations.

Spot prices that differ by location impose transmission costs on traders. These cannot be avoided by the use of CFDs, and they make trading risky. Some markets in transmission rights exist to provide a hedge for transmission costs. Since a trade always is allowed in the RT market, a financial transmission right is as good as a guaranteed physical transmission right.

Why is it so easy to insulate a bilateral trade from the spot energy price and so difficult to insulate it from the spot transmission price? A buyer and seller (or source and sink), considered as a unit, are unaffected by the energy price because their net position is zero. As a unit, however, they always take a net position in the transmission market; they consume transmission from generator to load. Because they take a nonzero net position in the transmission market, they are affected by the price of transmission.

The complaint of traders is that the transmission price is "ex-post: - it is established after they commit a trade instead of being posted ahead of time. Real-time transmission prices are impacted by the real-time physical conditions. They are susceptible to weather, generation outages, transmission outages, and other factors.

Transmission lines have capacity limits that must be enforced in order to protect the lines and the stability of the system. When these limits are binding, that is, when trades would like to have more capacity than is safely available, transmission is a scarce resource. Economics recommends that, whenever practical, a market be used to allocate what is scarce.

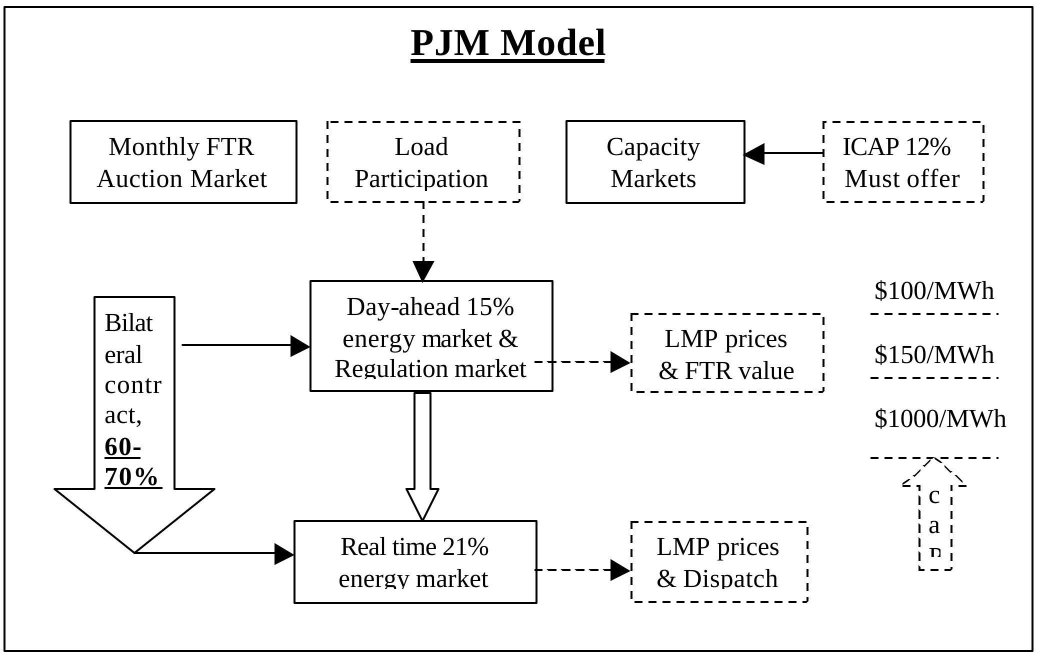
Financial rights reflect electrical reality; physical rights reflect an illusion – the notion that suppliers actually deliver *their* product to *their* load. (Emphasis in original) If supplier A sends power to load B and supplier B send power to load A, their shipments may physically cancel each other on the connecting power line with the result that no power flows from A to B or from B to A. Instead, supplier A's power goes to supplier B's customer and *vice versa*.

Supply and demand curves are neither constant nor completely predictable, so prices are risky. In a market with fully competitive transmission pricing, if a generator trades with load at the local bus, there is no charge for congestion. If a generator trades with a remote load, and there is a chance of congestion, the trade is exposed to transmission-price risk.

Transmission rights are needed to hedge long-distance forward trading but not to protect power lines. If the rights are well-designed, they will minimize forward-trading risks and the market will work much like the above example that has transmission costs but assumed no transmission-price risk. Trading at a distance, in any direction, will be uninhibited by price risk. Within the optimal set of generators, the matching of generators to loads is quite random. This will result in many counterflows between loads and generators, but because of physics, these flows will be netted out before they happen and the same optimal power flow will result as if local trading had been maximized. Similarly, transmission costs will net out and every generator and load will pay and be paid as if it had traded locally. Financial arrangements will reflect the physical properties of electricity.

PJM Market

Pennsylvania-New Jersey-Maryland (PJM) system operates the day-ahead energy market, the real-time energy market, the daily capacity market, the monthly and multi-monthly capacity markets, the regulation market and the monthly Financial Transmission Rights (FTRs) auction market. PJM introduced nodal energy pricing with market-clearing prices on April 1, 1998 and nodal, market-clearing prices (Locational Marginal Pricing (LMP): Appendix II) based on competitive offers on April 1, 1999. PJM implemented a competitive auction-based FTR market on May 1, 1999. Daily capacity markets were introduced on January 1, 1999 and were broadened to include monthly and multi-monthly markets in mid-1999. PJM implemented the day-ahead energy market and the regulation market on June 1, 2000. PJM plans to add a market in spinning reserves in near future.



* The difference with FERC Standard Market Design (SMD) is lack of Automatic Mitigation Procedure (AMP), though AMP is optional in FERC's SMD.

PJM's two-settlement system consists of two markets – a day-ahead market and a real-time balancing market. Separate accounting settlements are performed for each market. For the full year of 2001, real-time spot market activity averaged 6,563 MW during peak periods and 6,395 MW during off peak periods, or 21% of average loads. In the day-ahead market, spot market activity averaged 4,794 MW on peak and 4,877 MW off peak, or 15% of average loads.

Day-Ahead Market

The day-ahead market is a forward market in which clearing prices are calculated for each hour of the next operating day based on generation offers, demand bids, and bilateral transaction schedules and incremental and decremental bids which are purely financial bids to supply and demand energy in the day-ahead market. The balancing market is the real-time energy market in which hourly clearing prices are determined by the actual bid-based, least-cost, security constrained unit commitment dispatch. Separate accounting settlements are performed for each market.

PJM's day-ahead market enables market participants to purchase and sell energy at binding day-ahead nodal prices. It further permits customers to schedule bilateral transactions at binding day-ahead congestion charges based on the differences in the day ahead LMP between a transaction's source and sink locations. FTRs are available to hedge congestion in the day-ahead market.

All spot purchases and sales in the day-ahead market are settled at the day-ahead prices. PJM allows virtual bids so market participant can submit bids that are purely financial in order to arbitrage between the day ahead and real time market prices. Such bids are treated in the unit commitment process as if they were physical. PJM calculates the day-ahead final schedule based on the bids, offers and schedules submitted. Day ahead bids are of three types: energy bids by generators that self-commit, virtual bids, and multidimensional bids including cost and operating parameters by generators that want to be committed by PJM's central unit commitment algorithm. Generators that are committed by PJM are made whole on a 24 hour basis (i.e., PJM guarantees cost recovery). All self-committed and centrally committed units are scheduled for each hour in the day ahead through a security constrained bid based dispatch and the corresponding hourly LMPs are calculated. The day-ahead scheduling process will incorporate PJM reliability requirements and reserve obligations into the analysis. The resulting hourly schedules and LMPs represent binding financial commitments to market participants.

Real-Time Balancing Market

The real-time balancing market is based on actual real-time operations. Generators that have sold capacity and thus represent capacity resources must offer their energy in the day-ahead market. Any resource that is a capacity resource must offer its energy in the day-ahead market, regardless of any associated bilateral energy contracts. Available capacity resources that are not selected in the day-ahead scheduling (e.g., the offer price was higher than other generators and therefore the resource was not economically dispatched) may alter their bids for use in the real-time balancing market. If a generator chooses not to alter its bid, its original bid in the day-ahead market remains in effect.

A load-serving entity (LSE) has the obligation to own or acquire capacity resources greater than or equal to the peak load that it serves plus a reserve margin of about 18%. LSEs have the flexibility to acquire capacity in a variety of ways. Capacity can be obtained by building units, by entering into bilateral arrangements with terms determined by the parties or by participating in the capacity credit markets operated by PJM. Collectively, these arrangements are known as the Installed Capacity Market, or ICAP. The PJM capacity credit markets are intended to provide the mechanism to balance the supply of and demand for capacity not met via the bilateral market or via self-supply. Capacity credit markets were created to provide a transparent, market based mechanism for new, competitive LSEs to acquire the capacity resources needed to meet their capacity obligations and to sell capacity resources when no longer needed to serve load. PJM's daily capacity credit markets ensure that LSEs can match capacity resources with changing obligations caused by daily shifts in retail load. Monthly and multi-monthly capacity credit markets provide a mechanism that matches longer-term capacity obligations with available capacity resources.[16]

PJM's mitigation consists of the $1,000/MWh bid cap in the PJM energy market and the $100/MW bid cap in the PJM regulation market. To mitigate local market power, PJM limits the offers of units that are dispatched out of merit order to relieve transmission constraints to marginal cost plus ten percent. PJM has a number of additional rules designed and implemented in order to limit market power. PJM is investigating other rule changes to reduce the incentives to exercise market power.

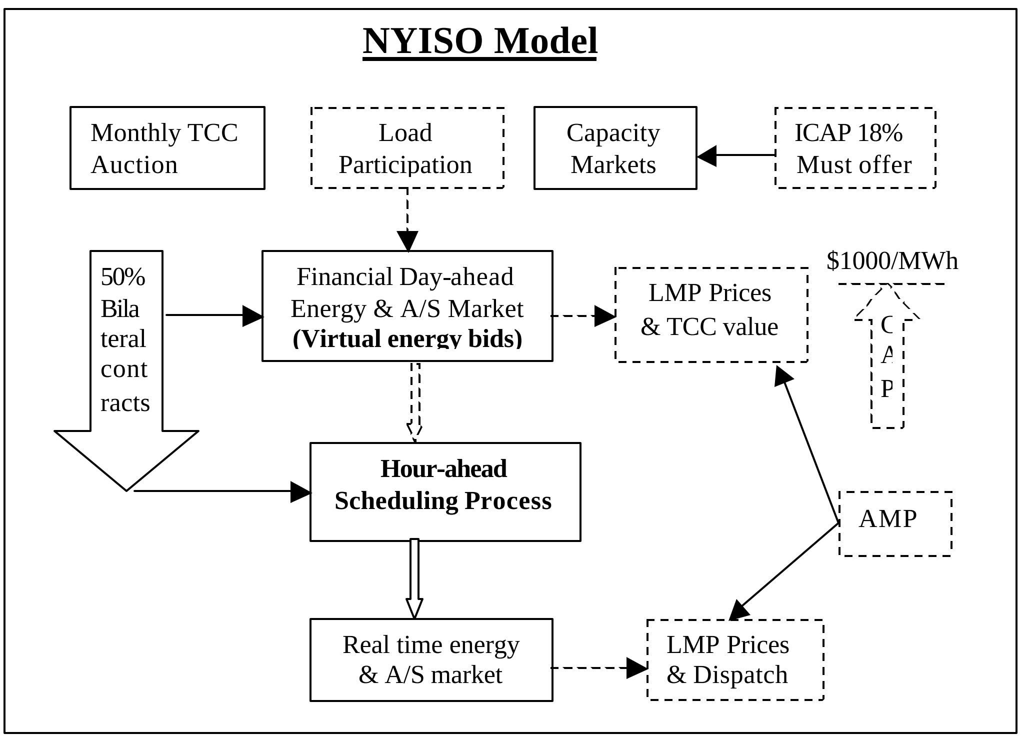
PJM introduced fixed transmission rights (FTRs) in its initial market design in order to provide a hedge against congestion to firm transmission service customers, who pay the costs of the transmission system. PJM introduced the monthly FTR auction market to provide increased access to FTRs and thus increased price certainty for transactions not otherwise hedged by allocated FTRs. In PJM, firm point-to-point and network transmission service customers may request FTRs as a hedge against the congestion costs that can result from locational marginal pricing (LMP).

[16] MOD would note that most ERCOT stakeholders have expressed the opinion that ICAP markets are not effective in providing an RTO with adequate generation reserves at reasonable prices. The PUCT has taken a different approach in its Generation Adequacy rulemaking (Project No. 24255).

New York ISO Market

The NYISO's existing market design includes a Locational-Based Marginal Pricing ("LBMP") congestion management system, day-ahead and real-time energy markets (with limited demand bidding), and fully optimized markets for ten- minute synchronized reserves, ten-minute non-synchronized reserves, thirty-minute reserves and regulation. The day-ahead market determines LBMPs at each generator bus and for each load zone for each hour of the next day, while the real-time market determines the spot price used to settle real-time transactions and differences between day-ahead schedules and real-time generation and load. LBMPs in New York employ s a fully nodal approach for supply, with a zonal approach for loads The NYISO also administers separate ICAP and Transmission Congestion Contract ("TCC") markets. In addition to a day-ahead market and a real time energy market, the NYISO operates an hour-ahead Scheduling Model to facilitate market operation. The Scheduling Model includes processes to dispatch generation, procure ancillary services, schedule external transactions, and set market-clearing prices in the day-ahead and the real-time markets based on supply offers and demand bids.

non-synchronized reserves, thirty-minute reserves and regulation. The NYISO also administers separate ICAP and Transmission Congestion Contract ("TCC") markets. In addition to a day-ahead market and a real time energy market, the NYISO operates an hour-ahead Scheduling Model to facilitate market operation. The Scheduling Model includes processes to dispatch generation, procure ancillary services, schedule external transactions, and set market-clearing prices in the day-ahead and the real-time markets based on supply offers and demand bids.



* The differences with FERC SMD is a Hour-ahead Schedule Model in NYISO

Day-Ahead Market

The day-ahead market clearing prices are calculated for each hour of the next operating day based on generation offers, demand bids, and self schedules. The day-ahead scheduling process will incorporate NYISO reliability requirements and reserve obligations into the analysis. Based on the load forecast, NYISO will issue day-ahead unit commitments to meet forecast demand and reserve requirements, and establishes day-ahead schedules for each generator. The resulting day-ahead hourly schedules and day-ahead LMPs represent binding financial commitments to the Market Participants. Financial transmission rights (FTRs) are accounted for at the day-ahead LMP values. NYSO is in the process of implementing a transmission constrained unit commitment algorithm that co-optimizes energy and ancillary service deployment on a locational basis. All schedules including bilateral transactions are subject to central commitment and redispatch. The resulting day-ahead hourly schedules and day-ahead LMPs represent binding financial commitments to the Market Participants. Transmission Congestion Contracts (TCC) and congestion charges for bilateral transaction are settled based on the day-ahead LMP values. The NYISO is in the process of implementing a state estimator, however its current LMP is limited to metered locations which are primarily generation buses. The NYSO control area is divided into 11 zones and load is charged zonal prices reflecting the average LMP within the zone.

The hour-ahead scheduling process updates the day-ahead commitment of resources based on forecast load for the next hour, using the Balancing Market Evaluation ("BME") model. This model also schedules non-dispatchable resources (resources that cannot receive updated dispatch instructions every 5 minutes) and external transactions. Approximately 90 minutes ahead of each hour, an evaluation takes place to ensure that the Day-Ahead First Settlement schedules meet all of the reliability requirements. Any new firm transactions will be scheduled by BME which could displace some of the day-ahead non-firm transactions. The results are then posted by 30 minutes before the hour as the schedule for the next hour.

Real-Time Market

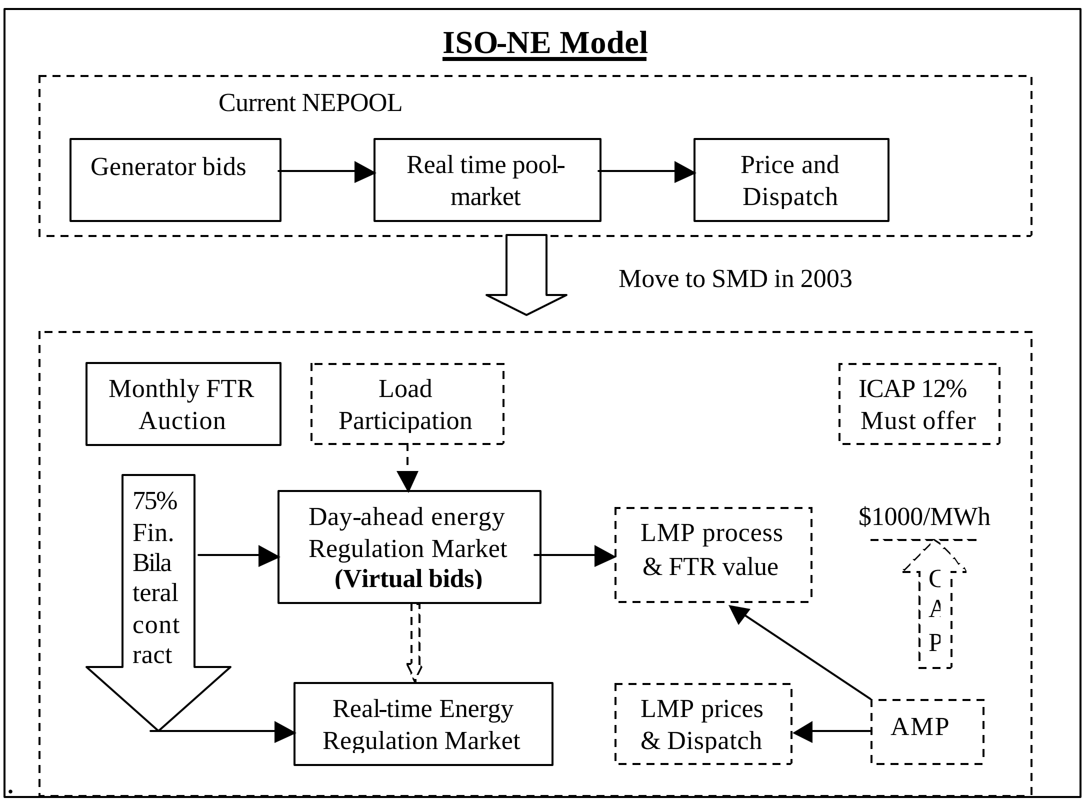
The real-time energy market establishes the final dispatch of supply to meet demand in each five-minute interval. Each of these markets utilizes locational marginal pricing that reflects transmission constraints and losses. In the real-time dispatch, Security-Constrained Dispatch (SCD) uses bid curves of the New York City Area (NYCA) generators to dispatch the system to meet the load while observing transmission constraints. Bid curves will consist of a combination of incremental bid curves provided by generators bidding into the LBMP market and decremental bid curves provided by generators serving bilateral transactions.

NYISO market allows virtual bidding by various resources. Virtual trading began in November 2001, allowing entities that do not serve load to make purchases in the day-ahead market. Such purchases are subsequently sold into the real-time spot market. Likewise, entities without physical generating assets can make power sales in the day-ahead market that are purchased in the real-time market. By making virtual energy sales or purchases in the day-ahead market and settling the position in the real-time, any market participant can arbitrage price differences between the day-ahead and real-time markets. For example, a participant can make virtual purchases in the day-ahead if the prices are lower than it expects in the real-time market, and sell the purchased energy back into the real-time market. The result of this transaction would be to raise the day-ahead price, due to additional demand, slightly and improve the convergence of the day-ahead and real-time energy prices, due to additional supply in the real-time.

ISO-New England

On May 1, 1999, ISO-NE, on behalf of New England Power Pool (NEPOOL), began to administer a wholesale marketplace for energy, automatic generation control, 10-minute spinning reserve, 10-minute non-spinning reserve, 30-minute operating reserve and operable capacity. With the exception of operable capacity, these products are currently bought and sold daily, by the hour. Market participants bid their resources into the market the day before, submitting separate bids for each resource for each hour of the day.

Early in 2003, New England will replace NEPOOL's existing bid-based single-settlement system with bid-based, security-constrained Day-Ahead and Real-Time hourly markets with locational marginal pricing ("LMP") including Financial Transmission Right (FTRs) and ICAP. At the outset, LMPs in New England will employ a fully nodal approach for supply, with a zonal approach for loads. All FTRs will be auctioned with the revenues produced by such auctions allocated to entities receiving Auction Revenue Rights ("ARRs"). NEPOOL's current Operating Reserve markets will be eliminated and a new spinning reserve market that is currently under development by PJM is expected to be implemented in New England in 2003. Similar to PJM, ISO-NE would schedule resources for energy to meet Operating Reserve objectives. Cleared/accepted offers for pool-scheduled generation in the Day-Ahead and Real-Time markets would be guaranteed to recover their as-bid costs through the receipt of Operating Reserve credits. SMD will also revise the Installed Capability ("ICAP") arrangements for New England by adopting a comprehensive new ICAP regime based upon the New York ICAP Market.



The differences with SMD are Virtual bids and Hour-ahead Schedule Model

The proposed SMD is very similar to what is currently operating in New York ISO but not operates a hour-ahead schedule model. The Day-Ahead Energy Market will produce financially binding schedules. The real-time market will address real-time differences in available resources, load and contingencies from the Day Ahead Schedule. Whereas NEPOOL's current single-settlement system establishes prices and schedules for five products, the proposed SMD will initially determine prices in the Day-Ahead and Real-Time Markets for only two distinct products: Energy and Regulation.

Participants who successfully schedule purchases, sales and/or transmission service in the Day-Ahead Energy Market will face associated obligations settled at the applicable Day-Ahead Energy Prices for the amounts scheduled. Consistent with the PJM design, the SMD will also permit Demand Bids, Decrement Bids, and Increment Offers and require Supply Offers for all available output of NEPOOL Resources receiving credit for Installed Capacity ("ICAP Resources"). Units not receiving credit for Installed Capacity in NEPOOL ("non-ICAP Resources") must offer all available energy not offered to another Control Area or to ISO-NE in the Real Time dispatch.

The Real-Time Energy Market will clear for any differences between the amounts of energy and ancillary services scheduled Day-Ahead and reflect Real-Time load, Participant re-offers (Day-Ahead), hourly Self-Schedules, self-curtailments, and any changes in general system conditions.

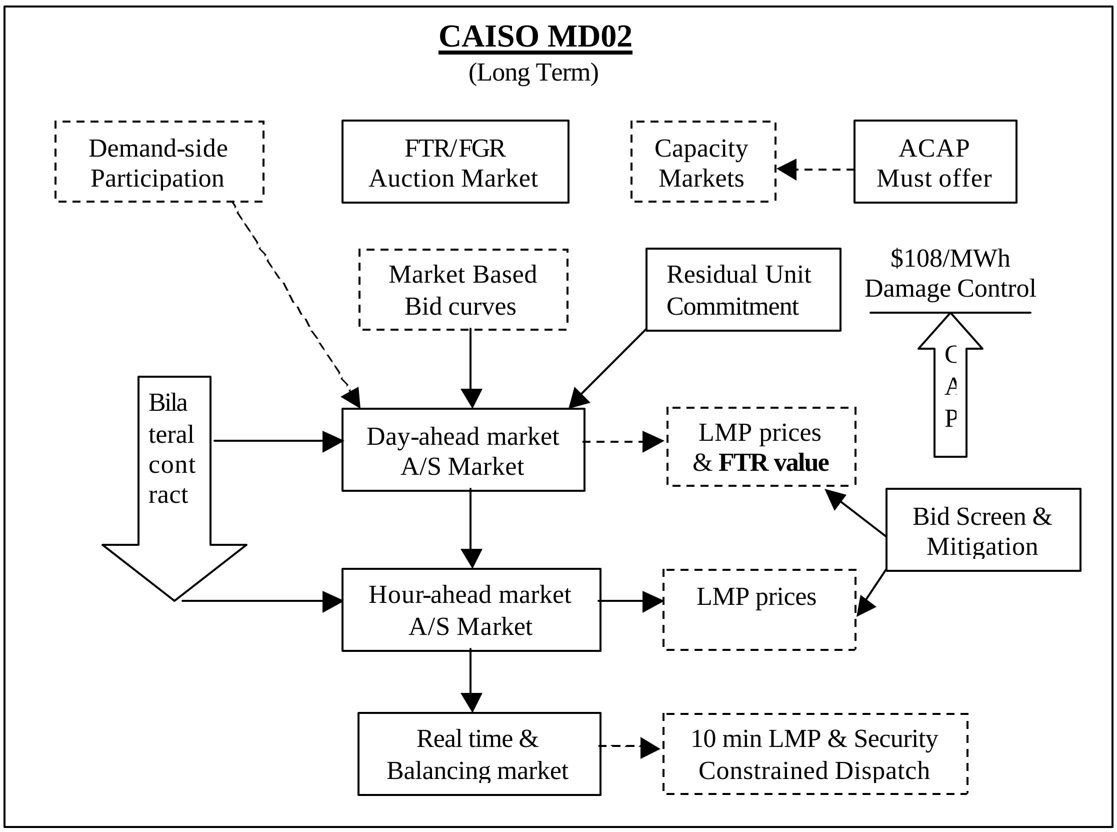
In addition, reserve bids were to be capped at the energy clearing price (ECP) rather than the hourly clearing price for reserves, and the $1000/MWh energy bid caps were to be extended during periods of capacity shortage. Because the rule specified that reserve bids were to be capped at the ECP, reserve caps were to be administered at the five-minute level. This process fosters convergence of day-ahead prices to their real-time values, so that inefficient price differentials will not be allowed to persist within a load zone. Similarly, FTR revenues may be capped if necessary to prevent persistent differentials between day-ahead and real-time LMPs for the same delivery and receipt locations within an hour.

ISO-NE anticipates that Load Serving Entities (LSE) may still desire to manage their peak load. The ISO encourages LSEs to develop with their customers peak-shaving programs that are fully controlled by the LSE. Such programs would not involve the ISO-NE settlement process in any manner. In submitting their Demand Bid in the Day-Ahead Market, the LSE can decide either to incorporate the managed load that they control or to wait for real-time to decide if they wish to activate it.

California ISO

The California Independent System Operator (CAISO) is a not-for-profit, public benefit corporation that is subject to FERC regulation. California ISO serves a population of 34 million. In 2000, the California economy consumed a total of 264 terawatthours of electric energy with a peak demand of about 53,000 MW. The 53.2 GW of industry generating capacity in California (1999) represents 7.7 percent of the 687 GW of utility generating capacity in the U.S. The industry generating capability in California is dominated by natural gas (36.3 percent) and hydroelectric (26.5 percent), while U.S. capacity relies heavily on coal (40 percent), followed by natural gas (21 percent).

The California MD02[17] proposed a three-settlement system, including the day-ahead market, the hour-ahead market, the real-time market based on Locational Marginal Pricing (LMP). The new market design also includes the Available Capacity (ACAP) Obligations, Firm Transmission Rights (FTRs), Price Cap and Automated Mitigation Plan (AMP), which are similar to the ISOs in the Northeastern of the U.S.



Day-Ahead Market

The ISO proposes to use a fully accurate model of the ISO transmission grid to adjust generation and load (and import and export) schedules to mitigate transmission overloads, ensure local reliability and

[17] California Independent System Operator Market Design 2002 Project Comprehensive Market Design Proposal April 19, 2002

produce locational marginal energy prices at each node of the grid. With this change the ISO will eliminate the distinction between zonal and local congestion and will accommodate commercial energy trading at a few key "trading hubs." Under the proposal, the ISO would evaluate whether day-ahead schedules include enough on-line resources to meet the next day's demand forecast, and if not, the ISO would be able to commit additional units.

Hour-Ahead Market

Numerous parties in California have expressed a need to move the hour-ahead market closer to real time, to enable late energy trades and schedule changes to shape supplies as accurately as possible to meet demand. The ISO is considering a simplified hour ahead market that would perform congestion management and energy trading, and would close to submissions perhaps as late as 60 minutes before the start of the operating hour. This change would also satisfy a longstanding demand by many parties for a 60-minute dispatch market, since real-time energy bids submitted to the hour-ahead market could be matched against load bids for the next hour or pre-dispatched by the ISO for imbalance energy.

Real-Time Market

Every ten minutes during each operating hour the ISO would run a "security-constrained economic dispatch" program to determine which resources to dispatch at what operating levels to meet real time needs. This approach would meet the ISO's operating needs most accurately and efficiently by fully taking into account all transmission constraints, local reliability needs, and generator operating constraints, as well as system imbalance energy needs. This approach would produce nodal real-time energy prices, which would be paid to supply resources but could be aggregated to larger geographic areas for settling imbalance energy purchases by load serving entities.

Ancillary Services Markets

The ISO proposes to perform ancillary service procurement simultaneously with day-ahead congestion management and the energy market, to obtain Operating Reserves and Regulation. The proposed Comprehensive Design will allow the ISO to eliminate Replacement Reserves.

Firm Transmission Rights (FTRs)

With the changes to congestion management as proposed above, the ISO will also need to change the design of its FTRs from the current path-specific variety to a point-to-point design that specifies explicit generator and load locations without explicit reference to the network pathways affected.

Price Cap and Automated Mitigation Plan (AMP)

To mitigate against excessive market power abuse, the ISO proposes a Damage Control Bid Cap (DCBC) that will limit the maximum bid allowed in the ISO's energy and ancillary service capacity markets. Beginning on October 1, 2002 and until market conditions are competitive enough to support a higher DCBC, the ISO proposes to set the DCBC at two times the estimated variable cost of a gas-fired generating unit with an incremental heat rate of 20,000, or \$250/MWh, whichever is greater. The ISO plans to increase the level of the DCBC over time as the structural elements necessary to support a competitive market improve and believes that the DCBC could eventually be increased to \$1,000/MWh, which is the bid cap level currently in place in the eastern ISOs.

Bid Screens and Mitigation

Beginning on October 1, the ISO proposes to implement individual resource bid screens and mitigation procedures in the day-ahead Residual Unit Commitment process and in the real time pre-dispatch process that occurs 45 minutes prior to the start of the operating hour. This mitigation element is similar to the Automatic Mitigation Procedures (AMP) utilized by the NY ISO, but would have more stringent bid and impact threshold levels. The ISO is recommending that bid reference levels be based on historical bids for all resources. The ISO further proposes a bid threshold equal to the lower of a 100% increase from a resource's reference level or $50/MWh, and a market impact threshold equal to the lower of a 100% increase or an increase of $50/MWh in the projected real-time market clearing price. This procedure would apply to all bidders into the markets to which the procedure is applied. As the ISO gains experience with the bid screen and mitigation procedures and if the overall competitiveness of the ISO markets improves, the ISO will consider raising the bid and price impact threshold levels.

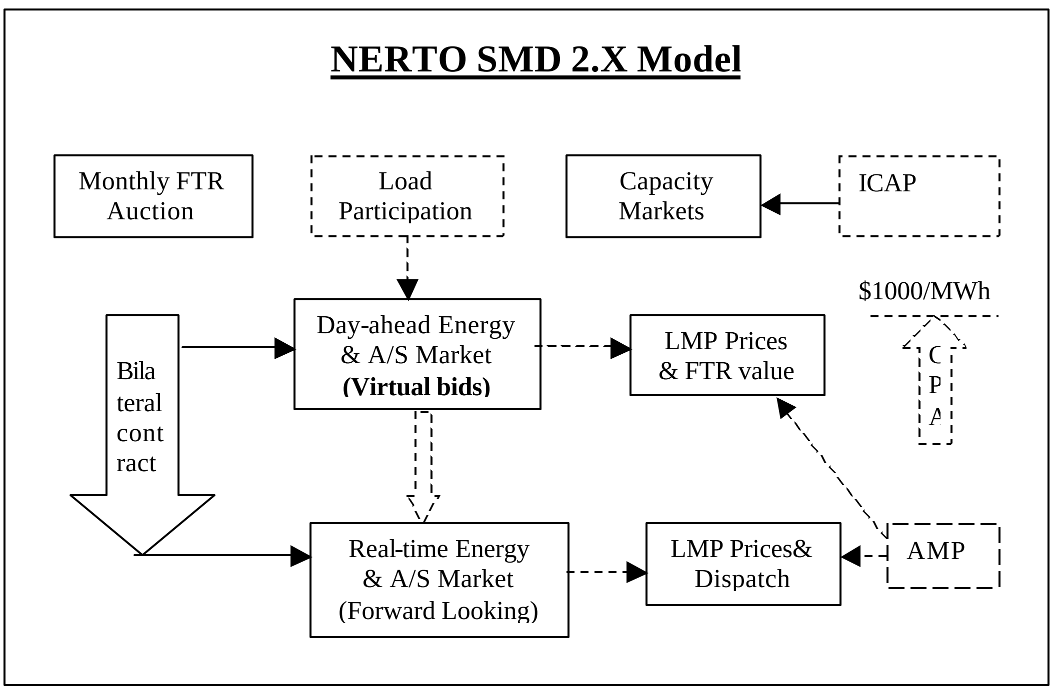
Available Capacity (ACAP) Obligations

The main purpose of the ACAP obligation is to enable the ISO to verify in advance that adequate capacity is available on a daily basis to meet system load and reserve requirements. Thus, the ISO believes that the proposed ACAP Obligation is essential to the ISO's core function – that of providing reliable transmission service. The ACAP Obligation will support reliable system operations by requiring LSEs to procure, in a forward-market timeframe, resources sufficient to satisfy the ISO's peak daily operating requirements. By requiring that such ACAP resources are made available to the ISO in the day-ahead market, the ISO can satisfy its objective of moving operating decisions from real time into the forward market – further supporting stable and reliable operations.

Northeast Market

In 2003, pending the appropriate approvals, the NYISO and ISO-NE will merge to establish Northeast Regional Transmission Operator (NERTO). The Petitioners expect the NERTO to reach its full implementation in the 2005/2006 timeframe. The seven-state NERTO region will encompass approximately 110,000 square miles with a population of over 33 million. This area includes two of the country's largest metropolitan areas, New York and Boston. The NERTO will have operational authority for the region's bulk power system, which includes 64,000 megawatts of generating capacity and 18,000 miles of transmission lines. The NERTO will have a number of interconnections with neighboring control areas (with their approximate nominal transfer capabilities): PJM (2,500 MW), Ontario (2,400 MW), Quebec (3,425 MW) and New Brunswick (700 MW). The wholesale markets in the 21 NERTO regions will supply electricity to over 14 million customers with a 2001 peak load of over 58,000 MW.

NERTO is developing its SMD in stages. ISO-NE is currently developing SMD 1.0, and SMD 2.0 will be developed for New York. SMD 2.X will be based on SMD 1.0 and SMD 2.0, including modifications to incorporate identified best practices. When fully implemented, the NERTO Market will include day-ahead and real time energy markets co-optimized with regulation and reserves markets, LMP-based dispatching and congestion management, a system of FTRs, security-constrained unit commitment, nodal ex post pricing, and a uniform ICAP market. Both physical and "virtual" bids and offers will be permitted in the NERTO-administered day-ahead energy market. Participants will be able to engage in bilateral or self-supply transactions as well as participating in the NERTO Market.



* The differences with SMD are virtual bids

Day Ahead Market

The day-ahead market commits generation to meet forecast demand and reserve requirements, and establishes day-ahead schedules for each generator. These schedules are financially binding and may be satisfied by generating or purchasing the scheduled quantity from the real-time market. The ISO also runs a Reserve Adequacy Assessment after the day-ahead market. If the purely financial day-ahead market with virtual bidding falls short of needed reserve, the ISO can commit to satisfy the reserve requirements. This arrangement allows all the freedoms of the day-ahead market to occur without endangering reliability.

Short-Term Scheduling

Short-term commitment software will be employed to update the day-ahead commitment of resources continuously based on forecast load and energy. This software also schedules fixed output resources such as block loaded combustion turbines (resources that cannot receive updated dispatch instructions every 5 minutes) and external transactions.

Real-Time Market

The NERTO real-time market will use a real- time scheduling and dispatch process consistent with its day-ahead security constrained unit commitment ("SCUC") model. This model includes a real-time, security-constrained scheduling process that looks ahead three hours and executes at 15- minute intervals and a dispatch process that looks ahead one hour and executes on five- minute intervals. The SCUC will replace the separate Balancing Market Evaluation and Security Constrained Dispatch mechanisms currently used in New York.

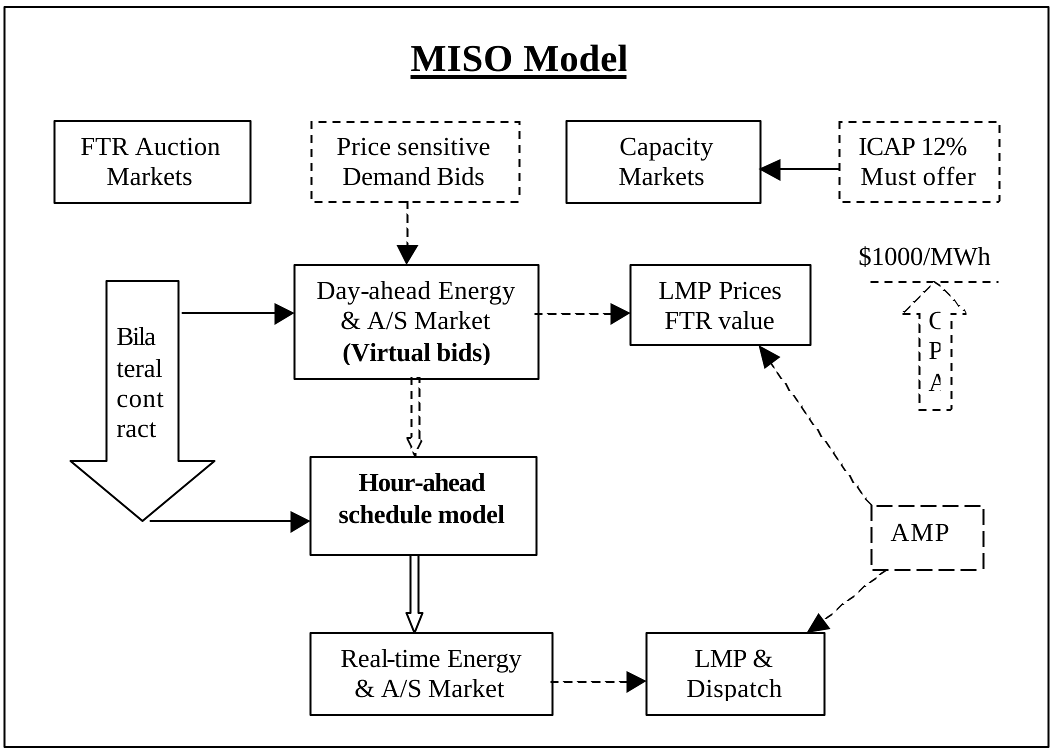
The NERTO will promote robust demand-side response mechanisms, including a day-ahead demand response program based on the current New York model, to be expanded through the Northeast. These demand-side mechanisms will ultimately include the ability for qualified demand resources to participate in the ancillary services markets.

The NERTO will also administer an ICAP market based on the unforced capacity design currently used in New York and PJM, or a new design in line with the FERC SMD NOPR. Under SMD 2.X, the NERTO will establish locational requirements for reserves and ICAP. It will also employ prospective mitigation measures that will be incorporated into its software to remedy market power abuses in the day-ahead market and in real-time.

MISO Market

The Midwest ISO was formed in 1996 as a voluntary association of electric transmission owners in the Midwest. The Midwest ISO is responsible for the electric transmission system spanning 15 states and parts of Canada. On December 20, 2001, the Midwest ISO became the first FERC-approved RTO in the nation.

In 2003 the MISO will implement a hybrid LMP approach. The MISO hybrid approach will build upon existing approaches commonly referred to as Locational Marginal Pricing for real time balancing, congestion mitigation and settlement, and the flowgate rights (FGRs) concept for the forward markets. MISO's SMD includes a day-ahead energy market, an hour-ahead scheduling model, a real-time energy market, a daily capacity market, an ICAP capacity market, a regulation market and a auction market of financial transmission rights that are a combination of point-to-point and flowgate rights. Both the day-ahead energy market and the real-time energy market markets utilize locational marginal pricing that reflects transmission constraints and losses.



The differences with SMD are Virtual bids allowed

Day-Ahead Market

In the day-ahead, market clearing prices are calculated for each hour of the next operating day based on generation offers, demand bids, and bilateral transaction schedules submitted. As is the case with NYISO, the day-ahead market also accepts virtual supply offers and virtual demand bids. The day-ahead scheduling process will accommodate MISO reliability requirements and reserve obligations. The resulting day-ahead hourly schedules and day-ahead LMPs represent binding financial commitments to the market participants. Financial transmission rights (FTRs) are accounted for at the Day-ahead LMP values.

The scheduling philosophy in the day-ahead energy market aims to schedule generation to meet the aggregate demand bids, virtual demand bids and external demand bids that result in the least-priced generation mix, while maintaining the reliability of the MISO footprint. MISO will also schedule additional generation in a reliability commitment as needed to satisfy the MISO load forecast and maintain operating reserves based on minimizing the cost to procure such reserves. MISO will also schedule generation resources based on basic principles of market economics to control potential transmission limitations that are binding in the transmission reliability analysis that is performed in parallel with and subsequent to the day-ahead market analysis.

Real-Time Market

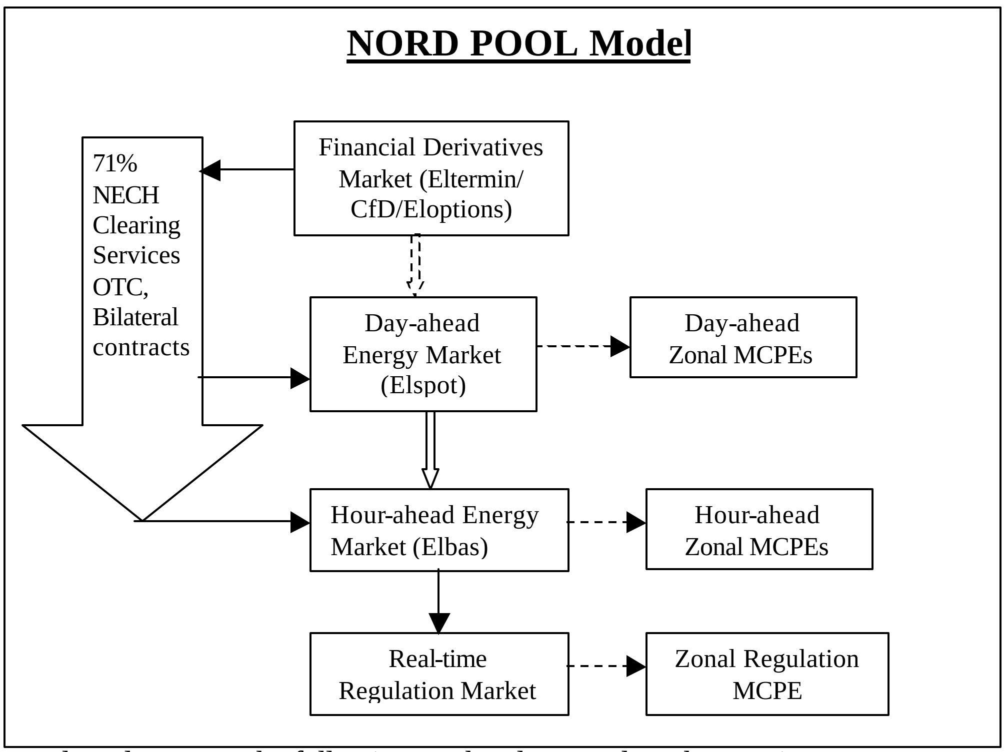
In the real-time energy market, the clearing prices will be calculated every five minutes based on the actual system operations security-constrained economic dispatch. Separate accounting settlements are performed for each market. The day-ahead market settlement is based on scheduled hourly quantities and on day-ahead hourly prices. In contrast, the real-time settlement is based on actual hourly (integrated) quantity deviations from day-ahead scheduled quantities and on real-time prices integrated over the hour. The day-ahead price calculations and the real-time price calculations are based on LMP.

Nord Pool

Nord Pool ASA, the Nordic Power Exchange, is the world's first multinational exchange for trade in electric power contracts. Nordel is a cooperative body made up of the transmission system operators (TSOs) in the Nordic countries (i.e., Denmark, Finland, Iceland, Norway, and Sweden). The objective of the organization is to "create the conditions for, and to develop further, an efficient and harmonized Nordic electricity market."

The population of Norway, Sweden, Finland, and Denmark totals about 24 million, which is about the same size as the PJM service territory (23 million) but significantly less than the population of California (34 million). Yet these four countries consumed about 392 TWh of electricity in 2000, compared to 262 TWh and 264 TWh in PJM and California, respectively.

Electric power production in Norway is almost 100% hydropower. Sweden and Finland use hydropower, nuclear and fossil-fuel-powered generation plants. Over 90% of Denmark's electricity comes from conventional thermal plants and combined heating and power (CHP) facilities. The table below shows the generating capacity in the four countries that make up the Nordic Power Exchange area served by Nord Pool.



Nord Pool operates the following marketplaces and market services:

- A day-ahead spot market for physical contracts (Elspot)
- A hour-ahead spot market for physical contracts (Elbas)
- A financial derivatives market –futures, forward, and option contracts (Eltermin, Eloptions)
- Clearing services for financial electricity contracts – Nordic Electricity Clearing House ASA (NECH)

- A real-time market for system operators to balance generation to load at any time during real-time operations, and to provide a price for participants' power imbalances.

Nord Pool Markets

The Nordic market is partitioned into separate bidding areas (Zones) each of which can have different prices if the contractual flow between bidding areas exceeds the capacity allocated by transmission system operators (TSOs) for spot contracts. Finland and Denmark each are a zone, with Sweden and Norway having two zones each. If there are no such capacity constraints, the spot system price is also the spot price throughout the entire Nordic Power Exchange area.

Within Sweden, Finland, and Denmark, grid congestion is managed by "counter-trade," based on bids from generators. Grid congestion that occurs in real time is managed by Nordic transmission system operators, by calling on bids in the real-time market.

Day-Ahead Market

Nordic market participants trade power contracts for next-day physical delivery at the spot market; hence the market is referred to as a day-ahead market. Trading is based on an auction trade system. The spot concept is based on bids for purchase and sale of power contracts of one-hour duration that cover all 24 hours of the next day. The market clearing price or system price for a particular hour is first calculated using only the bids for purchase and sale that participants have submitted. To do this, all purchase bids are summed to create a demand curve, and all sales bids are summed to create a supply curve. The point where the two curves intersect determines the system price for that hour.

Hour-Ahead Market

The day-ahead physical market aspects of Elbas allow its market participants to trade one-hour spot contracts after the Nordic Power Exchange's Elspot market results are published (at noon) to bids for next-day deliveries. Once Elbas changes are implemented during autumn 2001, the market will offer hour-ahead trading (down from the current two-hour gap before the closest delivery hour).

Real-Time Market

Bids in the real-time market are submitted to a transmission system operator (TSO) after the spot market has closed. Bids may be posted or changed close to the operational time, in accordance with agreed rules. Real-time market bids are for upward regulation (increased generation or reduced consumption) and downward regulation (decreased generation or increased consumption). Both demand-side and supply-side bids are posted, stating prices and volumes. Real-time markets are organized by Transmission System Operators (TSOs); market participants must be able to commit significant power volumes on short notice. TSOs list bids for each hour in priority order, according to price. TSOs use the priority-ordered lists for each hour to balance the power system, as needed. To resolve a grid power deficit, upward regulation is applied: the real-time market price is set at the highest price of the units called upon from the priority listing. Similarly, in a grid power surplus situation, downward regulation is applied: the lowest price of the units called upon from the list sets the real-time price.

The specific rules for determining the hourly price of power imbalances, based on the real-time market price, differs among the Nordic TSOs. Nevertheless, an imbalance always carries the risk of a financial loss, compared to balanced trade.

Ancillary Service Market

In Scandinavia, Nord Pool allocates to each member country the required amounts of regulation and reserves, each of which contracts separately for these services. This practice ensures that each control area contributes its fair share to maintain reliability of the system.

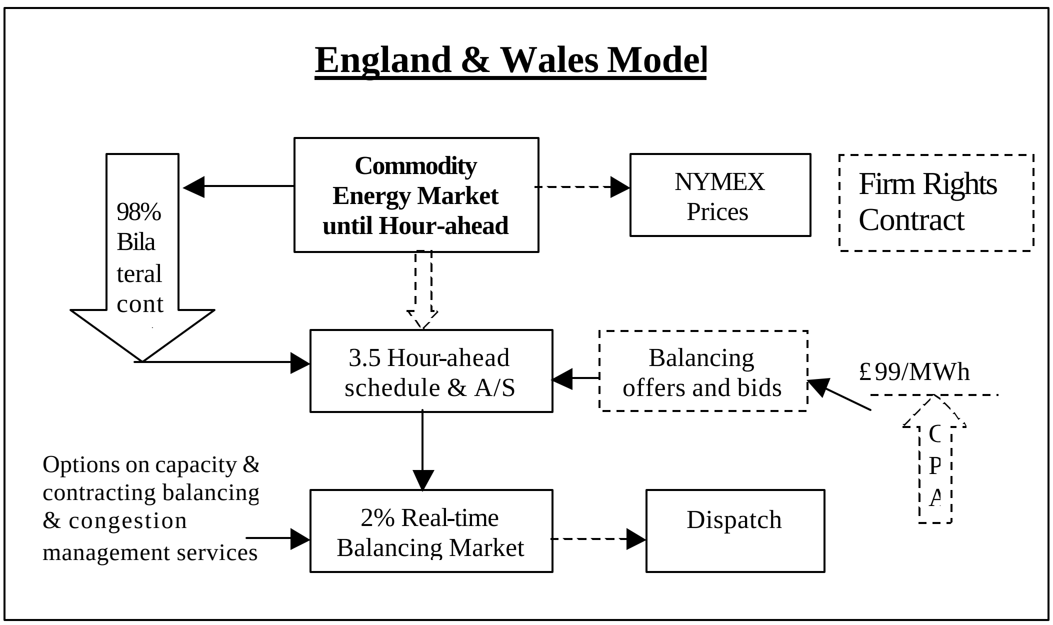
England and Wales

A key feature of the Electricity Act of 1989 was establishment of the Electricity Pool of England and Wales in 1990. The pool was the market for electricity trading in England and Wales from its opening in March 1990 until the New Energy Trading Arrangements (NETA) took effect in March 2001. A winter-peaking power system, England and Wales demand peaked at 51,012 MW on January 16, 2001. Total generating capacity in England and Wales in the winter of 2000/2001 was 67,695 MW, which translates to a reserve margin of 33 percent.

NETA began operation in England and Wales on March 28, 2001. Its extension to Scotland, called the British Electricity Trading and Transmission Arrangements (BETTA), starts in 2004. In its first year of operation, NETA increased competition and placed considerable pressure on wholesale prices, which had been kept artificially high by the arrangements under the Electricity Pool which NETA replaced.

Bilateral Markets

Under NETA, almost all electricity is bought and sold by contracting between willing buyers and sellers in over the-counter markets or in power exchanges. A small amount of sales, about two percent, are made in the Balancing Mechanism, the tool that National Grid Company (NGC) has as system operator to ensure that supply and demand match on a second-by-second basis.



3.5-Hour-Ahead Markets

Load-service entities must declare their positions not less than 3.5 hours before physical delivery. NGC then works to ensure that the "lights stay on" and the system is truly balanced and secured. NGC purchases long-term options on capacity and to purchase balancing services via long-term contracts – in each case via open and competitive procedures. A scheme of performance-based regulation (PBR) system allows NGC to intervene in energy markets to acquire reserves and balancing services, and also implicitly to discipline market participants by acting as a countervailing power to the monopoly power of some generators. The performance based regulation under the NETA system rewards NGC for reducing the congestion uplift below a bench mark level that is negotiated annually with the regulator and requires NGC to share cost overruns above that level. This mechanism creates incentives for NGC to optimize its congestion management by balancing its expenditures on out of merit redispatch of generators and investment in transmission expansion and improvements.

NETA is designed to improve opportunities for risk management via private bilateral contracts (especially ones of long duration) rather than expanding the use of market-clearing spot prices in a central pool. Long-term contracts could impact new generation companies and increased investment in new generating plants.

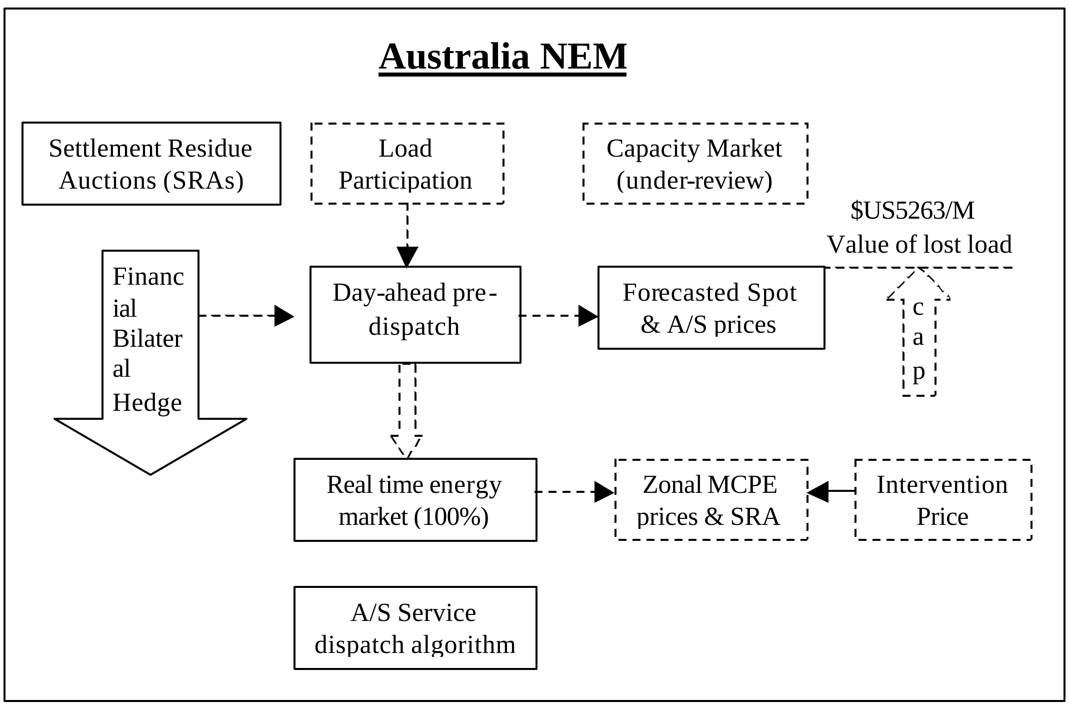
The UK's NETA presumes that private markets are sufficient for efficient energy trading and generator self-scheduling is conducive to system operation efficiency assuming generator can hedge their financial risks.

The efficient operations and low prices in the UK show that highly decentralized markets for energy, and self-scheduling by each market participant to meet its contractual obligations are functioning.

Australia National Electricity Market (NEM)

The National Electricity Market (NEM) of Australia commenced operation on **13 December 1998**, as part of the process of deregulation of the Australian power industry. The NEM is currently comprised of **five interconnected electrical regions.** These basically follow State boundaries (currently Queensland, New South Wales, Victoria, South Australia, and the Australian Capital Territory). Each region contains a regional reference node, which may be a major load center such as a city, or a major generation center, such as the power plants in the Snowy region. The regional reference node is where the Regional Reference Price (RRP), or **regional spot price** is set.

The National Electricity Market Management Company Limited (NEMMCO) operates a wholesale market for trading electricity between generators and electricity retailers. Generation output is pooled and all electricity must be traded through the spot market. NEMMCO calculates the spot price using the price offers and bids for each half-hour period during the trading day. The spot market is set and then settled by a centrally-coordinated dispatch process. Dispatch instructions are sent to each generator at five-minute intervals. Prices are calculated for dispatch intervals in each region. The dispatch prices calculated during each half-hour period are averaged to determine the spot price. This spot price is used as the basis for billing participants within the NEM for all energy traded. Generators are paid for the electricity they sell to the pool, and retailers and wholesale end-users pay for the electricity they use from the pool.



There is **Predispatch Forecasting** in NEM market**.** Predispatch is a short-term forecast of market activities used to estimate price, dispatch, and demand for the next trading day and energy flow across the interconnectors. Generators must notify NEMMCO of the volume and price of electricity they are able to supply and NEMMCO produces a demand forecast. This information is then collated to estimate total regional capability, thereby enabling NEMMCO to assess potential supply shortages.

Ancillary services include two parts: **Non-market ancillary services** are ancillary services which are not acquired by NEMMCO as part of the spot market but under agreements. The prices for non-market ancillary services are determined in accordance with the relevant ancillary services agreements. **Market ancillary services** are ancillary services which are acquired by NEMMCO as part of the **spot market**. The prices for market ancillary services are determined using the dispatch algorithm. The new frequency control ancillary service market arrangements were implemented in September 2001.

NEMMCO also monitors the future adequacy of generating capacity based on plant availability information supplied by generators and interconnector availability provided by network service providers against forecast electricity demand. Because demand for electricity supply fluctuates, both week-ahead and two-year forecast projections are made. These projections are called **Projected Assessments of System Adequacy (PASA).** PASA projections assist generator operators to plan maintenance and NEMMCO to schedule electricity production. Each year NEMMCO also publishes a Statement of Opportunities (SOO) which predicts market trends for the following ten years.

State Governments have traditionally regulated interconnector assets. However, under the NEM, regulation of interconnector assets is progressively being handed to the Australian Competition and Consumer Commission (ACCC). Regulated interconnectors and transmission networks in general receive a fixed rate of return that takes into account the value of their asset base. The amount of this return is determined by the ACCC and reviewed every three to five years. Unregulated or entrepreneurial interconnectors (or merchant links), however, rely on trading (the arbitrage between the RRP's of the two interconnected regions) in the wholesale market to derive their revenue. Unlike regulated interconnectors, they may also enter into **financial contracts** (which are not part of the wholesale market arrangements)**.**

The difference between the price of energy generated in one region and the price of that energy once it has been transmitted to another is called the **Inter-Regional Settlement Residue (IRSR)**. The Settlement Residue Auctions **(SRAs)** are intended to improve the efficiency of the NEM by promoting inter-regional trade. Only registered generators, market customers and traders are able to participate in the SRA.

A **price cap** is set under the Code and is the price automatically triggered when NEMMCO directs **network service providers** (NSPs) to interrupt customer supply in order to regain supply –demand balance. In this situation the spot price is referred to as the "Value of the Lost Load" (VoLL). On or before 31 March 2002, the cap is $5,000/MWh; and on and from 1 April 2002, it is $10,000/MWh, subject to an annual review by the *Reliability Panel*. The **market floor price** is a price floor which is to be applied to **dispatch prices**. The value of the market floor price is $-1,000/MWh.

The **demand-side participation** code changes have attempted to improve the attractiveness of registering as a scheduled load by increasing the flexibility.

New Zealand Wholesale Electricity Market (NZEM)

More than 60% of New Zealand's generation capacity is hydro based, using river flow systems and water stored in natural or man-made lakes. Thermal generation (powered by gas or coal) makes up most of New Zealand's remaining generation capacity, with the rest in wind farms, geothermal energy and cogeneration plants.

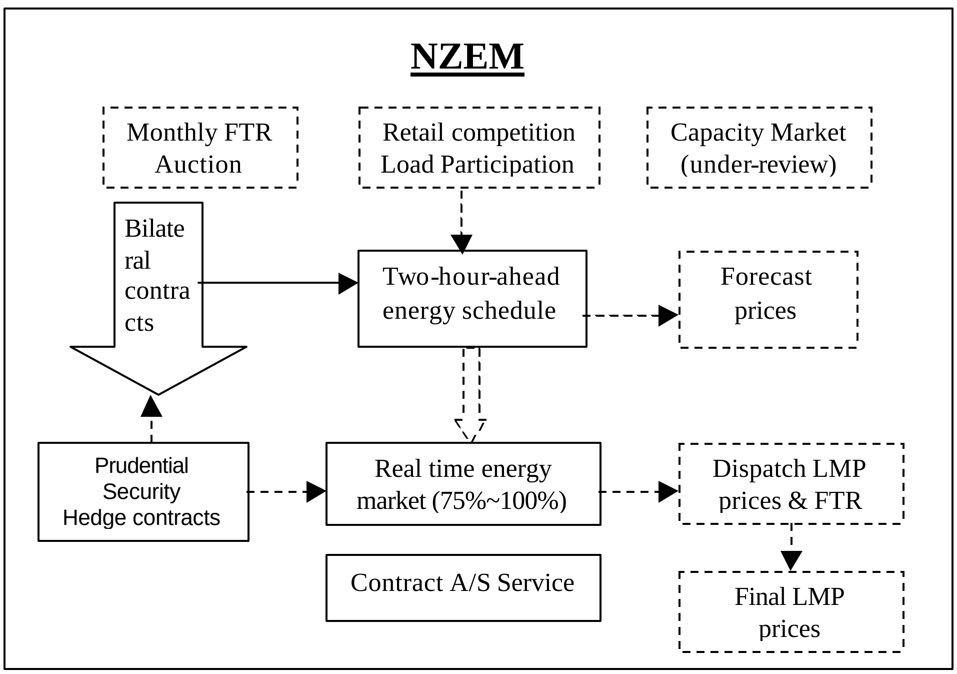
Real-Time Market

Real-time dispatch went into production on July 1, 2001, after a trial phase that began in February 2001. Rule changes in preparation for real-time dispatch have done the following:

Allowed automated electronic dispatch to become the main means of providing dispatch instructions – considered a necessity as the volume of dispatch instructions under real-time dispatch requires all processes to be automated

Separated the production of the real-time dispatch schedule from the dispatch process

Required the dispatcher to produce and publish this schedule as a service to the market.



*Canceled Day-ahead Market

Transpower provides pre-dispatch schedules every two hours. This establishes a detailed day-ahead generation dispatch schedule that will fulfill the forecasted demand. The schedules are developed from market participant load bids, generation offers, non- NZEM-member load forecasts and generation profiles. This information is overlaid with the grid operator's information on transmission status that will optimize dispatch in order to minimize congestion. A pre-dispatch schedule is produced at least once every two hours. Once it is published, participants can review forecast prices and revise their bids and offers up to two hours before dispatch.

As a dispatcher, Transpower is responsible for the real-time co-ordination of electricity transmission and ensures that real-time demand and generation are matched. Providing both dispatch and scheduling services, Transpower must account for generators and retailers that are not part of NZEM, but need to transport electricity across the national grid. The Dispatcher then sends generation instructions. The dispatcher gives market participants instructions to ensure that demand, security and schedule requirements are met. Instructions are also issued to meet reserve and reactive power requirements. Once the final dispatch is established, any deviation in the dispatch schedule is documented to maintain the process's transparency and integrity.

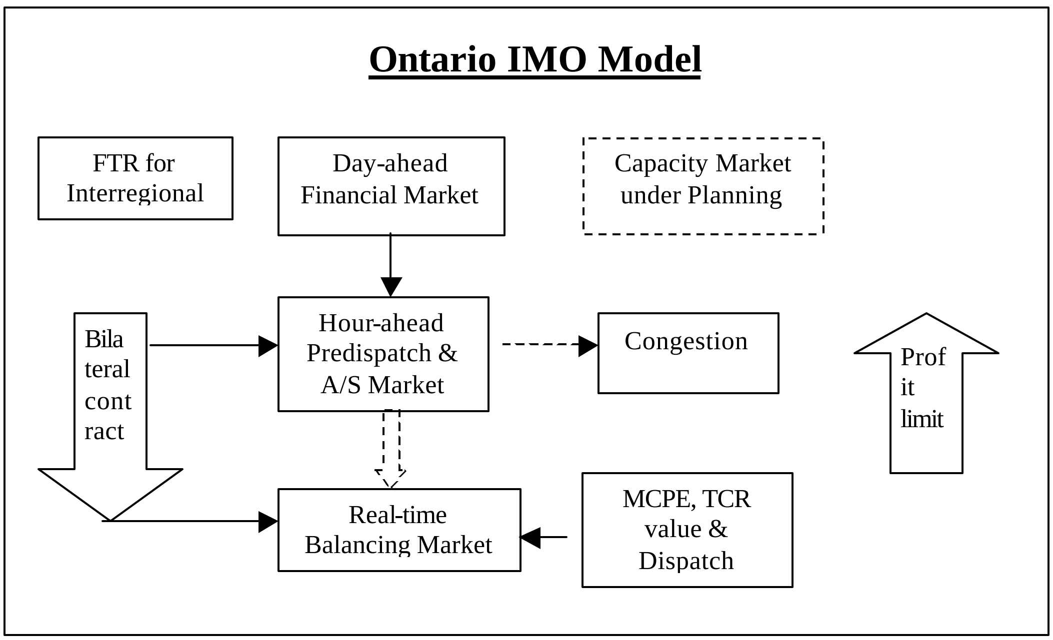
Through NZEM a price is established for each of 48 half-hour trading periods every day, at 244 connection 'nodes' on the national grid. The price at each of these nodes is set according to the cost of providing the electricity, which incorporates locational variations and the cost of providing reserve. These locational variations can happen because of transmission system outages, transmission losses and capacity constraints.

Between 70% and 80% of New Zealand's electricity is bought and sold through NZEM. Generators offer electricity into the marketplace and retailers then buy electricity from NZEM to supply their needs. Alternatively, generators and retailers or major users can enter into physical bilateral agreements outside the market.

Ontario Independent Electricity Market Operator (IMO)

The Ontario IMO (The Independent Electricity Market Operator) is a *non profit* corporate entity that administers Ontario's wholesale electricity markets and manage the reliability of the high-voltage power system with the normal summer peak demand of about 22,500 MW (25,269 MW in 2001), 30,000 megawatts of generating capacity, and 29,000 kilometers of high-voltage transmission lines. The IMO's generating plants include a mix of nuclear, hydroelectric, coal, oil and natural gas-fired stations.

The Ontario market model currently is similar to ERCOT model. Ontario IMO has no day-ahead market and does not use locational marginal Pricing (LMP). The Ontario IMO mainly relies on bilateral contracts directly between market participants. The IMO opened its wholesale market in May 2001. It plans to operate a day-ahead financial market, an hour-ahead predispatch mode, and a real-time market. The energy forward market will be a non-locational day-ahead market for energy delivered within Ontario, unlike the locational day-ahead markets previously described for the NYISO and ISO-NE. The IMO will auction financial Transmission Rights ("FTRs") to hedge the congestion charge between Ontario and each external zone. IMO is also considering additional markets such as a capacity reserve market.



Day-Ahead Energy Forward Market

The IMO will operate a single day-ahead Energy Forward Market based on one-part bidding. The day-ahead Energy Forward Market is purely a financial market and can be used to provide a settlement hedge for real-time transactions but is not used to physically schedule the operation of the Ontario transmission system, or to determine schedules for Ontario's external interties. Generation offers to sell into the day-ahead forward market will consist of an upward sloping one-part bid curve for incremental energy. Conversely, load bids to purchase from the market will consist of a downward sloping one-part bid curve. Offers to sell and bids to buy in the energy forward market will clear at a uniform Forward Market Clearing Price for Ontario for each hour of the dispatch day. The forward market clearing price will be determined by stacking the hourly supply offers and the demand bids and identifying the point of intersection of the resulting supply and demand curves.

Pre-Dispatch

Starting at 12:00 p.m. on the day before each dispatch day, and up to one hour before real time, the IMO will run a pre-scheduling program based on the bids and offers that it has received. The program is used to provide market information by way of hourly updates, which include expected hourly schedules and prices to all market participants.

The pre-dispatch program is primarily a forecasting tool that provides the IMO and market participants with advance information and projections necessary to plan the physical operation of the electricity system. If the predispatch schedules indicate that the IMO needs more energy or operating reserves to maintain the reliability of the grid, it may request the submission of additional bids and offers from resources that can be made available within the time required.

Real-Time Market

Ontario's real-time market will be based on offers and bids for incremental energy. Every five minutes the IMO will dispatch generators and loads based on their bids and offers and will determine a single unconstrained Market Clearing Price ("MCP") for Ontario. With a few exceptions, the five-minute MCP and dispatch quantities will be used for five-minute settlements with generators and loads. External schedules will be determined from an hour-ahead pre-dispatch program. They will be settled at the five-minute MCP, adjusted for an hourly congestion charge between Ontario and the external zone that is calculated in the hour-ahead pre-dispatch. Supply offers and demand bids into the Ontario real-time market can be modified without restriction until four hours before the real- time dispatch. Four hours before the dispatch, the IMO will impose a 10% limit on the magnitude of further price and/or quantity changes. Bids will become firm two hours before real time, although changes may be made if approved by the IMO.

Ancillary Services Market

In addition to energy, there are real-time markets for three types of operating reserves: ten-minute synchronized reserves, ten-minute non-synchronized reserves and 30- minute reserves. The IMO also enters into Reliability Must-Run Contracts with specific resources that are required to be available, or to be dispatched out-of- merit, to address local area transmission constraints or voltage requirements.

Congestion Management

The IMO will sell financial Transmission Rights ("FTRs") to hedge the congestion charge between Ontario and each external zone. The hour-ahead pre-dispatch process determines an hourly Intertie Congestion Price ("ICP") that the IMO will use to settle external transactions for that hour. The ICP for an intertie is the external zone price at the intertie point minus the Ontario uniform price in the hour-ahead prescheduling program. In Ontario, generators and loads and possibly boundary entities that are constrained-on or constrained-off will be paid a Congestion Management Settlement Credit (CMSC) that will be funded by uplift.

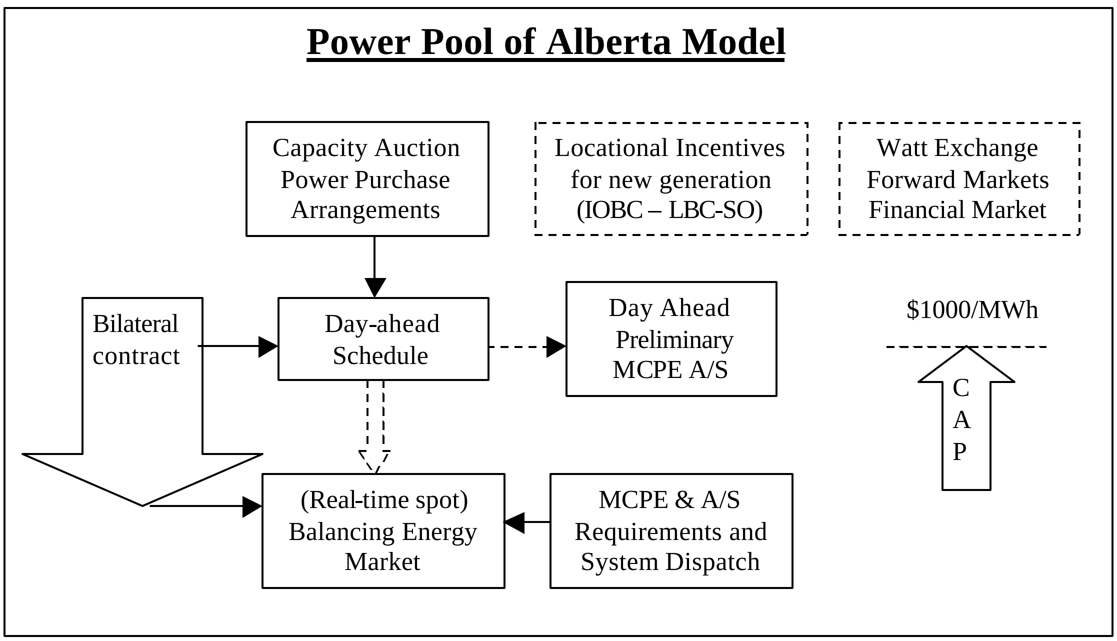
Price Cap

There are no price or bid caps in the Ontario market at this time, although the market rules state that the IMO Board may set a maximum price for energy and operating reserves. Market power mitigation plans for Ontario Power Generation limit the revenue that it can earn on 90% of its forecast domestic sales, but do not cap its bids. There is a limit to the profits that Ontario Power Generation can earn through power sales in Ontario.

Alberta Canada

The electric market in Alberta was deregulated in 2001. The Alberta market uses a zonal congestion model. Power generation is sold through the Power Pool of Alberta's spot market, Power Purchase Arrangements (PPA) bilateral contracts, and forwards contracts. Alberta has 11,590 MW of installed generation capacity to supply a peak demand of 7,934 MW. Coal fired and natural gas generation plants account for about 80% of Alberta's installed capacity with the remaining mostly hydro and about 1% is wind power and biomass. An additional 750 MW of generation capacity will be brought on line by the end of 2002.

The Power Pool of Alberta co-ordinates and monitors all aspects of Alberta's electricity market: real-time power sales, PPA, imports and exports with in the province. Since all energy is dispatch through the pool and has the responsibility to provide real-time control in order to operate the system safely, reliably, and economically as well as coordinate the operation of the interconnected provincial power grid with neighboring jurisdictions. Generation holder or PPA holders make offers to the Power Pool of Alberta. The spot price is based on the weighted average of the highest price paid for energy required to balance the supply and demand for the hour. Energy prices have been dropping since the market has opened. The market has a $1,000 /MWh bid cap.



Financial Market

Forwards are traded on the Watt Exchange, which is a futures market that trades electric power financial contracts for 1 month, 3 month and 1 year out.

Day-Ahead Schedule model

The Pool dispatches the required generation, import offers and demand bids to serve the actual system demand and exports. Companies that generate or PPA holders place offers to supply hourly blocks of energy at specific prices. Offers are submitted for a seven-day period and offer prices, for the first trading day, can't be changed. Electricity purchasers place bids to buy blocks of energy at specific prices. Bids, like offers, are placed for each hour of the next day and for the following six trading days with prices fixed for the next day.

For next day schedule, market participants must supply a unit specific schedule by 16:00 the day ahead. Shortly after unit specific schedule is submitted a preliminary market clearing price for energy is posted. Bids submit marginal prices on an hourly basis. Bids and schedules may be adjusted before real-time to represent the actual state of available resources. The Pool ranks offers and bids from least expensive to most expensive, and publishes a schedule for the next trading day.

Real-Time Market

In the real-time spot market, generation or PPA holders make offers to the Power Pool of Alberta. Balancing energy deployment is kept to a minimum without impacting system reliability. The spot price is based on the weighted average of the highest price paid for energy required to balance the supply and demand for the hour. All power producers receive the hourly Pool Price for power generated and all purchasers pay the Pool Price for power received. This is the MCPE that is published for the hour. The market has a $1000 /MWh bid cap.

Ancillary Market

System services which include reserve requirements, both spinning and non-spinning (power-up), and interruptible load services to the Power Pool are competitively obtained by the Transmission Administrator.

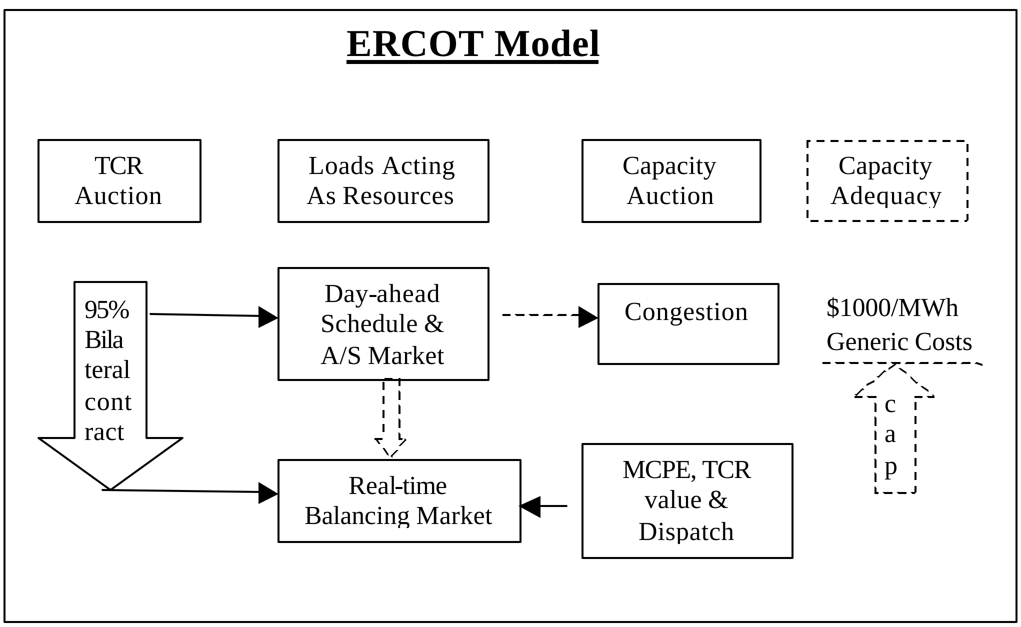
Congestion Management

At the present time, the TA uses bilateral contracts to procure Transmission Must Run services in the more isolated NW part of Alberta. The Alberta market has Invitation Offer to Bid Credit (IOBC) and Location Based Credits Standing Offer (LBS_SO) incentives to courage generation development in zones that would reduce congestion. Recently, the Alberta Energy & Utilities Board held a hearing over the future of congestion management in Alberta. No final decision has been made.

ERCOT Market

The Electric Reliability Council of Texas (ERCOT) is a single control area based upon the zonal model that uses both portfolio and unit specific dispatch instructions to resolve local congestion. ERCOT conducts a residual energy market for Balancing Energy Service (3 % - 5% of total demand) and ensures the reliability of Texas electric grid. On November 1, 2002, ERCOT is expected to implement "Relaxed Balanced Schedules." This market change is expected to increase the percentage of Balancing Energy Service used to meet market energy needs. ERCOT is a Min-ISO, similar to that in the UK, which uses dispatch only in real-time operations for balancing and congestion management rather than a Max-ISO, with full control of unit dispatch and a full unit commitment.

ERCOT has operated day-ahead ancillary service markets and the real-time balancing energy market since July 31, 2001. ERCOT began monthly and annual Transmission Congestion Rights (TCRs) auction market in February of 2002. In addition, in compliance with a rule issued by the Public Utility Commission of Texas, monthly and annual generation capacity auctions have been conducted by certain incumbent utilities. ERCOT day-ahead ancillary services include regulation up, regulation down, responsive (spinning) reserves, and non-spinning reserves.. ERCOT operates under a zonal model and employs two steps to implement security-constrained dispatch. In the first step, ERCOT clears the predefined commercially-significant-constraint (CSC) congestion, dispatches zonal balancing energy, and determines the market clearing price for Balancing Energy Service for each congestion zone. In the second step, ERCOT uses resource specific premiums and unit specific instructions to clear local constraints.



Bilateral Contracts

The bilateral market represents the bulk of delivered energy in Texas. Prices are based on mutual agreement or long-term contract between the parties, and are not known by ERCOT. These agreements are incorporated into base energy schedules which are submitted to ERCOT on a daily basis. These schedules account for about 95-97 percent of the end-user electric energy requirements in ERCOT.

Day-Ahead Ancillary Service Market

ERCOT day-ahead ancillary services include regulation up, regulation down, responsive (spinning) reserves, and non-spinning reserve services. Market participants can self-provide their ancillary service requirements or allow ERCOT to procure these services on their behalf. The market system is designed to seek the lowest-cost solution to maintaining system reliability consistent with ERCOT protocols. ERCOT procures the ancillary services not self-arranged by the Qualified Schedule Entities (QSEs) through bids and the market clearing process, which results in the Market Clearing Price of Capacity (MCPC). The day-ahead market operates from 6:00 am to 6:00 pm on the day prior to the operating day.

Day-Ahead Schedule

ERCOT requires QSEs to submit the schedules for their bilateral contracts, conducts the security-constrained analysis, and publishes system congestion information. ERCOT conducts a capacity analysis on a Day-Ahead basis which forms the basis for the procurement of Replacement Capacity in Day-Ahead. After the close of the Day-Ahead period, the Adjustment Period begins. QSEs can adjust their schedules and bids throughout the Adjustment Period. The Adjustment Period ends when the Operating Period begins. The Operating Period is comprised of the Operating Hour and the hour preceding the Operating Hour. Based on its analysis of schedule changes, Resource Plans, load forecasts, and other system conditions, ERCOT may procure additional ancillary services during the Adjustment Period by announcing the need to procure additional Services and opening subsequent markets.

Operating Period

ERCOT receives incremental and decremental Resource Premiums for the real-time balancing energy services (used to solve local congestion) as part of the Day-Ahead Resource Plan submissions. During the Operating Period, ERCOT evaluates the availability of Balancing Energy Service. If more than 95% of the available Balancing Energy has been deployed in a zone, ERCOT deploys Non-Spin. ERCOT procures Balancing Energy Service for each 15-minute interval. If required, ERCOT will use Resource-specific energy bids to resolve local (intra-zonal as opposed to inter-zonal) congestion, procure out of merit energy to resolve local congestion or for voltage support, or procure non-spinning reserves when extreme weather or system conditions require increased capacity to be online.

Real-Time Market

The Real-Time balancing energy market clearing occurs 20 minutes prior to the operating interval, by which point the right amount can be predicted using short-term forecasting tools. The bid stack for balancing energy is fixed for the entire hour but the energy market clearing price is adjusted every 15 minutes and is posted 15-20 minutes before the start of the operating interval. Balancing energy makes up the difference between the total ERCOT electricity requirements and the sum of the base energy schedules. It may also be used to manage transmission congestion (see more below on congestion management). The market process accepts bids in ascending order of price until the total quantity required is obtained. The bid price of the last quantity accepted for Balancing Energy Service sets the Market Clearing Price of Energy (MCPE) for that 15-minute interval.

Capacity Adequacy

ERCOT currently has no formal capacity market comparable to an ICAP market. The Commission is developing a generation adequacy rule which likely will use a mechanism that differs from ICAP markets known in the U.S. ERCOT utilities have traditionally sought to maintain a planning reserve margin of 15 percent. However, in mid-2002, the ERCOT Board approved a 12.5 percent reserve margin requirement. Comparatively high reserve margins are necessary because the system cannot rely on imports, due to its isolation from surrounding Interconnections. In 2000 and 2001, the reserve margins at peak were 14 percent and 21 percent, respectively. From 1995 to January 2001, 22 new generating plants, totaling more than 7,600 MW, were built in the ERCOT region. This represents 10.9 percent of total generating capacity; during this same period, peak demand grew by 24.5 percent. An additional 22 plants, totaling 11,850 MW, are under construction and scheduled for completion by June 2003. Combined cycle plants and wind turbines have been the capacity additions of choice. In Fall 2002, Centerpoint and Reliant have announced that a number of plants would be retired or taken off line.

Congestion Management and Transmission Congestion Right (TCR)

ERCOT uses a zonal commercial model and two steps to solve zonal and local congestion in conjunction with a security-constrained dispatch. In the first step, ERCOT clears the predefined commercially-significant-constraints (CSC) congestion, dispatches zonal balancing energy, and determines the market clearing price for each congestion zone. The Balancing Energy Service offers are procured by ERCOT in each zone for zonal load balancing and for inter-zonal congestion relief. The market-clearing price for energy (MCPE) is determined in each zone based on the zonal offer curves for balancing energy. If there is no interzonal congestion, the MCPE is the same for the entire ERCOT region. In the second step, ERCOT uses Resource specific premiums to clear local constraints and to issue Resource specific instructions to relieve local (operational) congestion. Generators submit resource-specific premiums that specify the additional payments (in addition to the zonal MCPE) that they require for the deployment of INC or DEC balancing energy from the associated, specific, resource.

Transmission congestion rights (TCR) were implemented in ERCOT along with the implementation of direct assignment of interzonal congestion charges in February of 2002. ERCOT initially adopted a simple flow-based transmission right approach and flow-based congestion charges. ERCOT is moving toward a combinatorial auction for TCRs. Congestion charges are imposed on QSEs based on the flow that their scheduled interzonal transactions induce on the three commercially significant constrained corridors. ERCOT runs annual- and monthly- TCR auctions.

Competitive Solution Method (CSM) [18]

The Commission is currently evaluating CSM. The CSM is designed to intervene in the market only if a bidder actually uses its market power position to drive up the MCPC. To detect potential anticompetitive conditions, the CSM tests (a) that the total MW offered in the bid stack is at least 115% of the capacity ERCOT needs to procure for that interval, and (b) that a pivotal bidder does not set the MCPC. A bidder is pivotal if removing all of its capacity leaves the remaining bid stack short of what ERCOT needs for that market interval. The MCP limit is calculated by removing all pivotal bidders from the bid stack after extension of the market, subtracting the most expensive 5% of the remaining capacity, and multiplying the highest resulting offer price by 1.5.

If all bidders are pivotal (in which case an MCP limit could not be calculated), ERCOT would pay bidders on an out-of-merit (OOM) basis using verifiable costs. All bidders are pivotal when ERCOT procures all, or nearly all, of the bid stack.

Retail Competition

Most restructuring paradigms in the United States (and around the world) focus on the wholesale market, anticipating that retail competition will follow. Unfortunately, these expectations often are not fulfilled. By contrast, the ERCOT market restructuring focused from the start on retail competition and charged the ISO with facilitating such competition through central management of customer switching. The pilot market that opened in July 2001 allowed 5 percent of the load to be switched to competitive retailers. As of January 2002, all retail customers in Texas are eligible to switch their retail suppliers.

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[18] Application of Competitive Solution Method to Data from ERCOT Ancillary Capacity Services Market Oversight Division Staff Report David Hurlbut, Ph.D. Julie Gauldin, M.Sc.

Appendix

Table 2
Summary of Market Design

	Market	Bilateral Market	Day-Ahead Market	Hour-Ahead Schedule	Real-Time Market	ISO-Run Futures Exchange	Bilateral & Self-Scheduled	LMP	ICAP[19]	FTR	Price Cap	AMP	LAAR	Retail Competition
Existing Market Design	NORD POOL			Market			71%		[20]	CfD				
	New Zealand						<25%		[21]					
	Australia	Financial Hedge	Schedule							SRA				
	England		Private				98%							
	PJM						64%							
	NYISO						50%							
	NEISO						40%							
	Ontario		Financial								Profit limit			
	Alberta		Schedule											
	ERCOT		Schedule				97%			TCR		TBD		
Proposed Market Design	FERC SMD													
	NERTO													
	MISO													
	California			Market										

[19] Capacity reserve margin requirements other than ICAP are being considered at FERC and at the PUCT.

[20] Under consideration

[21] Under consideration