Market Pricing Working Group

Locational Pricing – Summary of Other Jurisdictions

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INTRODUCTION

Locational pricing is a pricing approach that addresses congestion costs by reflecting the cost of transmission constraints and the cost of delivering energy to the next increment of load at a specific location on the grid. Typically congestion pricing includes both transmission costs and the cost of losses. Using this pricing mechanism, buyers and sellers experience the actual cost to deliver energy at their location on the transmission system. Taking into account the physical aspects of the transmission system separates locational pricing from uniform marginal clearing price which typically ignores transmission limitations.

This paper discusses the congestion pricing methodologies for New England (ISO-NE), Pennsylvania-New Jersey–Maryland Interconnection (PJM), Texas (ERCOT), California (CAISO), Midwest Independent Transmission System Operator (MISO), and New York (NYISO). For all jurisdictions examined, congestion is managed through locational pricing which for many is a change from their initial market design. The paper has been formatted as follows:

- Description of the ISO
- Initial market design for congestion management
- Discussion of any changes to this design including what precipitated the change
- A short description of locational pricing in their market

ISO NEW ENGLAND

Description

ISO New England (ISO-NE) created in 1997 is a regional transmission organization (as of February 1, 2005), serving Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. ISO-NE meets the electricity demands in the region's service area population of 14 million settling about one quarter ($11 billion) of the power sold in the region (the remainder is sold through negotiated, long-term contracts). The peak demand for region set August 2, 2006 is 28,021 MW.

Initial Market Design

ISO-NE first launched a single energy clearing price wholesale market in 1999. The energy clearing price for each hour (the weighted average of 5 minute real-time marginal prices) was set by matching requirements to a supply stack arranged in merit order. When transmission constraints blocked the most economic dispatch of the system, ISO-NE would constrain up or down generating units. The entire New England region paid uplift equal to the costs associated with relieving the congestion and the generators in the constrained regions received side-payments[1] to cover operating costs. No payments were made to resources constrained down. Resources running as a result of being constrained-up that were flagged as operating at lower operating level (most often the case) were not eligible to set the real-time energy price. Bilateral transactions were paying a uniform congestion price that did not reflect the cost that the transaction may have caused to the system.

Changes to the Design

The uniform pricing and uplift approach to transmission congestion was proving inadequate. More often than not constrained up generators were not setting the energy clearing price and the real-time price was held lower than it should have been, which sent inappropriate price signals to the market. The market power mitigation procedures often kept generators in constrained-up situations from recovering their full costs. ISO-NE did not experience generators self-scheduling to avoid dispatch, as real-time marginal prices were often so low when congestion arose that there was little incentive to find ways to avoid being dispatched down. The system failed because it presented the wrong incentives to market participants. In Order 2000, FERC expressed concern over uniform pricing's lack of incentives for generation and transmission citing and expansion. ISO-NE experienced new generation in low priced regions and closure of generation where it was needed despite the constrained-on payments. ISO-NE was interested in allowing market participants flexibility in scheduling bilateral transactions, buying and selling through the spot market, and minimizing the use of administrative controls but the single energy clearing price was not representative of the reliability constraints on the grid. For bilateral transactions, the transmission usage charges should have been equal to the difference of the prices at the source and destination rather than a market-wide uplift value.

[1] The lower of its bid price and a maximum established under the market power mitigation procedures.

Current Market Design
By March 2000, ISO New England completed its assessment of their market and planned to apply changes known as Congestion Management and Multi-Settlement Systems (CMS and MSS), systems. On March 1, 2003 ISO-NE implemented a Standard Market Design with locational pricing, day ahead and real-time markets and expanded risk management opportunities.

The aim of CMS was to address transmission congestion in the New England market through the implementation of locational prices for electricity. MSS was geared toward moving the New England market from a single settlement to a multi-settlement system, including day-ahead and real-time markets.

The ISO New England's Congestion Management System specifies locations (defined as nodes, load zones and a hub) where participants submit offers and bids, markets settle, and locational prices are calculated. Nodes (of which there are over 900) are points where power is injected or withdrawn from the system and correspond to a physical bus or collection of busses within the NEPOOL Transmission System at which locational prices are calculated. Locational pricing assigns the cost of congestion and losses to each of these locations. External/proxy nodes are proxy buses used for establishing locational prices for energy traded between New England and neighbouring systems. There are eight load zones. The zonal locational price is the load-weighted average of the locational price at the nodes that comprise the load zone. The hub is a specific set of 32 pre-defined fairly unconstrained nodes, designed to facilitate bilateral trading (including long-term commercial energy trading). The price at the hub should not be affected significantly by congestion and is the simple average of these pre-defined nodal prices. The hub is used to establish a reference price for energy purchases, for the transfer of day-ahead and real-time adjusted load obligations, and for the designation of FTRs. Generation is priced nodally, while load (demand) is settled using the zonal prices.

Each node's locational price represents the cost of serving an increment of load at a particular location creating a market-based process for pricing energy when the system needs to be re-dispatched to relieve congestion. Ex-post nodal locational prices are based on observed generator performance, rather than that assumed for ex-ante dispatch rates. This methodology enforces market discipline, because it permits generators to set price only if they have followed dispatch instructions. Although the day-ahead market in ISO-NE is purely financial in nature, it is also based upon a least-cost, security constrained dispatch. Thus, day-ahead locational prices send accurate signals about the conditions expected in the real-time market, and provide participants with appropriate signals for hedging requirements.

PJM

Description
The Pennsylvania-New Jersey–Maryland Interconnection or PJM is located in US mid- Atlantic region coordinating the movement of electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. The service area has a population of about 51 million and a peak demand of 139,746 MW set July 17, 2006.

Initial Market Design
PJM opened its market on April 1, 1997 with a model of uniform market clearing pricing (MCP) for energy in the real-time dispatch market. The pricing model treated the entire PJM system as a single zone, stacking generator offers to meet load requirements and assuming no transmission congestion to arrive at a hypothetical dispatch and an "unconstrained price" for the entire system. In real-time, PJM would dispatch out-of-merit generators to solve for system transmission congestion. Under these "constrained on" operations, the MCP would be the offer price of the highest increment of energy that would have been requested to operate by PJM in an "unconstrained" (no congestion) system. The system would pay the more expensive generators to run and average these "congestion costs" over all users. The model included two other noteworthy features. First, the generators that were "constrained off" would not be paid, even though they had offers below the unconstrained price. During market development, there were objections to adopting any system that depended on paying generators not to run. Second, market participants had the option to schedule bilateral transactions separate from the bid-based economic dispatch of the ISO, with a separate payment for their share of the total congestion cost at the average cost rather than marginal value of the transmission.

Changes to the Design
The features of the market not to include constrained off payments and to allow the flexibility to use self-scheduled bilateral transactions or to participate in the coordinated spot market caused significant congestion on the system starting in June of 1997. Incentives at the margin when the system was constrained caused many generators to self-schedule their power day ahead to avoid real-time economic dispatch instructions that constrained them down. PJM quickly moved to having too few controllable generating units with which to manage the transmission constraints. Unable to fix the inappropriate pricing incentives, PJM resorted to administrative mechanisms to prohibit bilateral transactions or declare a "minimum" generation emergency during the peak generation period. PJM was fully aware of the incorrect incentives of their congestion pricing and the problems they created. But without the authority to change the pricing rules, the ISO had no alternative but to restrict the market. PJM applied to FERC for changes to their congestion pricing model in mid 1997.

Current Market Design
The FERC approved the PJM plan to move to locational pricing in November 1997. By April 1998, PJM had moved to a locational pricing based market structure to deal with problems encountered with the initial market structure based on uniform price.

PJM

PJM operates the day-ahead and real-time energy markets, the daily, monthly and multi-monthly capacity markets, ancillary services market and financial transmission rights auction market. PJM accepts both bilateral schedules (account for approximately 70% of market) and voluntary bids of their market participants. Clearing prices are calculated day–ahead for each hour of the next operating day based on generation offers, demand bids, bilateral transaction schedules and incremental and decremental bids. The real-time market using these schedules, and bids, determines the security constrained economic dispatch for power flows and the associated locational marginal prices. PJM recognizes about 1990 "nodes" within their system, and calculates prices based on where a given block of electricity enters the system and where it exits (the "source node" and the "sink node"). Locational marginal prices are calculated by determining the next increment (1 MW) of load at the lowest cost, while observing transmission limits. Sensitivity factors help calculate the price to deliver power to every location in PJM in the least expensive way.

In real-time when further transmission constraints develop (outside the security constrained system), PJM dispatchers are responsible to dispatch and re-dispatch units in order to meet the load and alleviate any additional transmission constraints. Since these generators are higher cost units (or they would have already been in service), an additional Transmission Congestion Charge is added into the locational price. The Transmission Congestion Charge applies to all, but the actual amount depends on the locations of the "source" and the "sink." It is for this reason that posted day at hand locational prices are for information purposes. Settlement quality locational prices are posted only after next day when the locational pricing verification process confirms that manual dispatch has been incorporated into the pricing model appropriately. Generators (source) get paid at generation bus locational price and loads (sink) pay at load bus locational price. The transmission usage charge for bilateral transactions is the difference in the locational prices between origin and destination.

An accompanying system of Fixed Transmission Rights (FTR) provides financial hedges between locations. A trading hub, a mathematical aggregation of many nodal prices which is defined to create a relatively stable price reference point is used to create a price index that the forward markets can utilize.

NEW YORK ISO

Description
The New York Independent System Operator (NYISO) took over operation of the state's bulk electrical system on Dec. 1, 1999. NYISO was charged with providing open access to the transmission system while coordinating the daily operation and ensuring the reliability of the New York bulk power system. At that time, NYISO opened with all standard markets including the day-ahead and real-time energy, reserve, and regulation markets, as well as Transmission Congestion Contracts (TCC) and Installed Capacity (ICAP) Market auctions. The NYISO has a service area with a population of 19.2 million and settled $10.7 billion in 2005. The peak demand for region was set on August 2, 2006 at 33,939 MW.

Initial Market Design
From the beginning the cornerstone of the NYISO market operations was locational pricing based on the cost of providing the next MW increment of load at a specific location on the grid taking into account generation offer price and physical aspects of the New York transmission system. NYISO uses a base price at a reference bus against which losses, congestion, shift factors, penalty factors and other system mathematical quantities are calculated.

Current Market Design
Typically, bilateral contracts account for about 50 percent of total energy volume (load, wheel throughs, exports, and imports). For the remainder of the market, the day-ahead market accounts for about 45 – 50 percent, and the real-time accounts for the balance.

In the day-ahead and real time markets, locational prices are calculated at each of the over 400 generation buses (points of injection) and for each of the 11 load zones (calculated as a weighted average price based on generator locational prices and generator bus load distribution factors). Buyers pay the zonal price in which they take delivery of electricity (or the point of withdrawal for transmission congestion contracts), and sellers receive the generation bus price at the supply point. Bilaterals pay a NYISO transmission usage charge (equal to marginal congestion and losses charge).

There are also hourly boundary prices for the 4 neighbouring areas (New England, Hydro Quebec, Ontario Hydro, and PJM). Proxy buses represent generation and load outside of the NYISO system, since neighbouring systems cannot be tracked in detail. Each system connected to the NYISO is represented by one proxy bus that can serve multiple generators (sources) and multiple loads (sinks). In order to consider all transactions for each external system on an equal basis, only one proxy bus is used for each system.

The energy and congestion components of the locational prices for each proxy bus are calculated against a reference bus (Marcy). These calculations are made in the same manner as for other buses in the NYISO system. The loss component of locational pricing is calculated for each proxy bus using delivery factors that are based on the weighted average of all boundary buses represented by that proxy bus.

DAM prices are determined on an hourly basis for each generator bus, eleven load zones and for the four proxy buses. After accounting for generation offers, demand bids and scheduled bilateral transactions, the day-ahead locational prices are determined by adding the marginal cost of energy, the marginal cost of losses and the marginal cost of congestion.

In the real-time spot market, locational prices are calculated at five-minute intervals based on generation and energy transaction bids and actual grid operating conditions. To avoid overloading certain lines and equipment in real-time, the NYISO may deviate from its least-expensive bid-price and re-dispatch higher cost electricity (out-of-merit generation) to ensure that no constraints are violated. This causes a locational difference in costs and, because many bidders compete for existing transmission capacity across key interfaces, the price increases. The increases are the cost of congestion, which can be a significant factor in the price of electricity particularly in the eastern part of the State, New York City and Long Island.

Also, out-of-merit generation, either up or down, can be requested by the NYISO for security of the bulk power system, for example during communication failures, or because the real time commitment (RTC) does not successfully run. The energy provided during the out-of-merit condition will be paid at the real-time market locational price rates, but out-of-merit units may not set locational rates. The unit will be provided a supplemental payment, if its day-ahead margin is not met and required to recover its bid real time cost, consistent with the rules for bid production cost guarantees. Any supplemental payments will be charged to all loads.

There are two hedging mechanism for congestion Transmission Congestion Contracts (TCC) and Contract for Differences (CFD). The revenue from TCCs (purchased through NYISO auction) provides holders a hedge to congestion related transmission price fluctuations. CFD provides a financial hedge against locational price volatility at a location and are purchased in a secondary market.

CAISO

Description
On March 31, 1998, SCE, San Diego Gas and Electric and Pacific Gas and Electric's control areas were combined into one large control area under the direct control of the California Independent System Operator (CAISO). The ISO operates a small fraction (less than 5 percent) of the total wholesale electricity marketplace— using markets only to allocate transmission space (operates 75% of high voltage grid), maintain operating reserves and match supply with demand of over 30 million Californians. The majority energy is purchased via third party markets and contracts. Peak demand was set on July 24, 2006 at 50,270 MW.

Initial Market Design
The CAISO grid is subdivided into three zones (roughly geographic - northern, central and southern) separated by inter-zonal interfaces. Within each zone, there are many intra-zonal interfaces. In the current "day ahead" timeframe CAISO does not optimize unit commitment in advance or find and implement efficient day-ahead schedules. Rather companies (scheduling co-ordinators) submit balanced schedules for transmission (anticipate customer demand match that demand with an equal amount of generation supply) for a day-ahead scheduling process. The current scheduling process does not require the schedules be feasible within the overall grid but rather between the zones – a very simple radial network model with no intra-zonal congestion is used. Also, day-ahead schedules are not financially binding. Day-ahead, CAISO makes a series of adjustments to these schedules for reliability reasons using network models that can rearrange the schedules to prevent inter-zonal bottlenecks. Market Participants can submit incremental bids to supply more power, or decremental bids to reduce power output because of oversupply or congestion on transmission lines. If a zonal interface between the points is congested, congestion charges[2] are applied to transactions along the congested path and result in zones having different prices. If there is no congestion, the zones will have the same uniform market price.

The remaining network congestion that is within a zone is not seen in the day-ahead time frame. The ISO computer systems were not designed to look at intra-zonal congestion from the day-ahead schedules as it was also assumed (incorrectly given the current situation) that congestion within the same zone would be minimal in scope and cost. This system limitation creates operational difficulty and added costs. Control room staff are often forced to rearrange schedules in real-time to mitigate for the day-ahead schedules that can't all actually flow due to intra-zonal congestion. Again the ISO can use incremental and decremental bids to relieve congestion on transmission lines. Scheduling co-ordinators receive payment for extra generation they supply or are billed for extra energy they need to meet the demand of their customers. CAISO is concerned that using a zonal pricing method can allow out of merit dispatch to be used as a lever for market power under conditions of intrazonal congestion. Experience over the last few years has illustrated many examples where generators anticipate that a specific transmission line will be congested and schedule their unit(s) far beyond the limited local transfer capability in the day-ahead timeframe, thereby forcing the CAISO to use the generators decremental bids in real-time to mitigate the resulting congestion ("dec-game"). Recently there has been a significant problem with the addition of new power plants in the

[2] A usage charge for the cost to transfer power across an interface.

CAISO control area. Some of the newly constructed power plants are connected to very congested sections of the power grid. As many as 1,700 megawatts of electricity can be "stranded" at power plants due to inaccessibility to the grid.

Changes to the Design
California's financial day-ahead energy markets ceased to exist when the California Power Exchange shut its doors in 2001. Instantly there was an increased reliance on the ISO who did not have appropriate market features in the day-ahead time frame. Short-comings in the real-time markets were amplified. The current system with its reliance on real-time schedule "re-dispatch" has proved more costly than necessary, creates unnecessary reliability risks and operational challenges for the ISO. Also, currently CAISO decides which resources will be used for reserves (ancillary services) in a manner that is independent from its energy dispatch decisions. This results in less efficient use of generation capacity. Transmission and generating citing inefficiencies have been attributed to current lack of pricing transparency.

Proposed Market Design
In its market redesign and technology upgrade (MRTU) proposal, the CAISO proposes seven major system projects including an integrated forward and real-time markets network model with economic dispatch with locational pricing that would remove much of the current out of sequence dispatch and locational pricing. The network model will co-optimize ancillary services and energy and introduce security constrained unit commitment. MRTU will add a financially binding day-ahead market that is expected to make it easier for all participants especially smaller participants. MRTU has a November 2007 go-live date.

CAISO will utilize a full network model to solve congestion. The model will better reflect the true costs of serving load by location providing a consistent methodology to price transmission and energy. The design which includes locational pricing will reveal the actual cost of serving consumers at each specific location (node) on the transmission grid. Those responsible for creating the congestion will pay for it rather than the current method that socializes costs to the overall market. Locational prices calculated at over 3,000 nodes will be paid to generation and other dispatchable resources that bid into the CAISO's markets. For non-dispatchable load, the CAISO will calculate a single price for each of three major utility service territories, which will be load-weighted averages of each area's locational prices. Locational price will reflect the marginal cost of providing energy from a reference bus (a distributed reference bus with pricing nodes that are weighted throughout the system.), the marginal costs of congestion, (measured between a node and the reference bus) and the marginal cost of losses (real power losses as measured between that node and a reference bus). Improved monthly and annual transmission rights will be offered to customers to hedge against all congestion charges not just inter-zonal congestion. Transparent locational marginal prices in the day-ahead market will make it easier for suppliers located outside of California to sell their excess power into California at a competitive price. Also, demand response programs are expected to benefit by transparent day-ahead pricing.

MISO

Description

The Midwest Independent Transmission System Operator (Midwest ISO or MISO) was founded in February 1996 when transmission owners voluntarily came together to create an independent, unbiased organization to manage the flow of electricity in the Midwest. MISO began commercial operations of its new, Day-Ahead and Real-Time electricity markets on April 1, 2005. MISO operates within 15 states (Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Montana, Missouri, Nebraska, North Dakota, Ohio, South Dakota, Virginia, and Wisconsin) and the province of Manitoba (transmission services only). The MISO footprint includes 15.1 million customers and energy settlement is approximately 42 billion dollars annually. On July 31, 2006 a record demand peak was set at 136,520 MWs.

Initial Market Design

Similar to the NYISO markets design, locational pricing was the pricing methodology used from the beginning in the MISO markets implementation. MISO argued that development of transparent and efficient spot markets would change economic incentives and produce significant intermediate and long-term efficiency benefits. MISO believes that establishing markets with LMP as the pricing basis ensures that the most cost effective dispatch of resources will be obtained for the generation and the transmission that is available to the market at any given time. LMP provides a system for allocating scarce electric resources. Nodes in the transmission system exhibiting consistently high LMP prices signal a scarcity of resources – a scarcity of transmission, generation or a combination of the two. Also, if properly implemented, FTRs will provide an adequate hedge against the cost of congestion.

Current Market Design

On April 1, 2005, Midwest ISO opened its Day Ahead, Real-time and FTR markets. The markets design supports centralized, security-constrained unit commitment, security-constrained economic dispatch and locational pricing. MISO uses LMP to settle energy sales and purchases, to calculate transmission usage charges and to settle FTRs in the day-ahead market. The locational pricing model (commercial model) calculates power costs at 1,540 defined locations (called CPNodes) taking into account not only energy costs but also the cost of congestion and marginal losses for each location. MISO uses FTRs to hedge congestion charges in the day-ahead Market.

The Commercial Model using locational prices is a financial representation of the physical network model used to facilitate operation and settlement. Nodes representing physical points of injections or withdrawals or an aggregate price of injections or withdrawal points on the system filter into commercial pricing nodes. The published LMP represent the price at these commercial pricing nodes (sinks and sources). Generation and metering are directly associated with commercial pricing nodes. Demand is represented at the nodal level. But for scheduling, bidding and settlement a market participant can bid demand at an aggregated level. Load can be settled at load zones which are comprised of multiple nodes. There are five commercial trading hubs where prices are calculated by pre-determined fixed weighted-average LMPs of specified buses within the hub. In addition to pricing points used for commercial trading, hubs can also be used as source and sink in transaction delivery and receipt. Settlement occurs with ex-post LMPs to account for differences such as actual load differed from forecast load, actual unit performance did not equal dispatch instructions or changes in system topology. There are LMP pre-processing rules designed to determine a unit's eligibility to be a price setter based on performance (instructed vs. measured performance).

ERCOT

Description
Electric Reliability Council of Texas (ERCOT) ISO was formed in 1996 to ensure an impartial third-party organization was overseeing equitable access to the power grid among the competitive market participants throughout the state of Texas. On July 31, 2001, the existing 10 control areas in the region were consolidated into a single control area allowing for centralized of power scheduling and procurement of ancillary services to ensure reliability. On January 1, 2002, ERCOT launched the competitive retail electric market. ERCOT provides power flow to approximately 20 million Texas customers – representing 85 percent of the state's electric load and about 75 percent of the Texas land area. On July 17, 2006 a record demand peak was set at 62,396 MWs.

Initial Market Design
The wholesale electricity market consists of a day-ahead ancillary services market and a real-time balancing market, currently based on a zonal commercial network model of five zones (North, West, South, North-east, Houston) separated by four inter-zonal commercially significant constraints (CSCs – four South-to-North, West-to-North, Northeast-to-North, South-to-Houston). The model approximates behaviour of the transmission network addressing the significant congestion paths and is reviewed and updated annually. The simplified model was designed to match ERCOT's adequate generation capacity, sufficient transmission resources and minimize ISO intervention avoid full control of unit dispatch and a full unit commitment market. ERCOT uses the day-ahead load forecast to develop an ancillary services plan which identifies and allocates ancillary services needed for each hour of the next day to qualified service entities (QSEs) based on their share of demand served. There is no day-ahead centrally dispatched energy market. Rather, "Qualified Scheduling Entities (QSE - currently 80 registered) submit balanced schedules of generation and load to ERCOT. All schedules are accepted. Deviations between scheduled and actual generation and load are managed in the real-time balancing market by deploying balancing energy bids. Balancing energy bids are not required to be by individual generating unit. QSEs submit zonal portfolio energy offers with resource-specific premiums which allow the QSEs the flexibility in moving their own resources in the market. The ISO does not necessarily control which specific resources are dispatched under a zonal portfolio energy offer. This market is also used to re-dispatch generation for transmission congestion between (inter) and within (intra) zones. A 2002 change to the real-time balancing market that charged inter-zonal congestion rents directly to those responsible for the congestion (direct assignment) rather than uplifting to all market participants saw a significant reduction to inter-zonal congestion. Incentives to "over-schedule" and then get paid to relieve congestion (similar to the California "dec-game") were significantly reduced by this market change. Intrazonal congestion is relieved if possible by dispatching local balancing energy resources. Redispatched resources are paid market clearing premiums if a competitive solution exists otherwise they get out-of-merit energy payments. Very little (about 2% to 5%) of the total energy is transacted through balancing energy market with remainder 95% to 98% of the market is arranged through private bi-lateral contracts. The intra-zonal congestion charges are uplifted to all market participants on a load-ratio share basis. A locational price is calculated for each zone and reflects the value of last balancing energy service bid dispatched to clear the

predefined CSC congestion. Transmission congestion rights (TCRs) are offered for CSC congestion between zones.

Changes to the Design

A number of problems have been identified in the zonal commercial network model. The model's simplified network design is not addressing issues in the actual network. Considerable "intra-zonal" transmission constraints are not represented in the commercial network model. QSE portfolio bidding of resources by zones poses difficulties for system operators as they are uncertain which resources in a zone will actually be used and has led to significantly increasing out-of-merit energy payments. There are no incentives for QSEs to use resources that relieve congestion because they are paid to curtail output in congested areas. Growth in independents such as efficient combined cycle gas turbines generators, are often under utilized as they are limited to serving only in the balancing market. Requirements for balanced scheduling limits trade opportunities and price transparency. Overall ERCOT has poor system-wide coordination of generation decisions. Lack of precise market-based pricing of energy limits the encouragement of generation expansion and resource competition. Small participants face barriers to entry as only the largest participant can keep track of the frequent protocol revisions. While ERCOT allows for bidding of loads, many loads are having difficulty meeting performance criteria that was based on the characteristics of generation resources and as such demand that can actively participate in ERCOT is very limited. The current market is not sufficiently transparent to allow for monitoring and detection of market power abuse and the current portfolio bidding can be gamed.

Proposed Market Design

ERCOT plans implementation of an ISO-administered day-ahead energy market using nodal pricing. Energy and ancillary services will be co-optimized day-ahead and possibly also in real-time market. A reliability unit commitment will replace the existing replacement reserve service and out-of-merit capacity. In real-time ERCOT will implement and run a security constrained economic dispatch (SCED) every five minutes (settlement remaining on a 15 minutes basis), using offers by individual resources and actual shift factors by each resource on each transmission element. The redesigned grid model will consist of more than 4000 nodes and will replace the current congestion management zones. The congestion will be managed using individual units instead of the current portfolio based offers. Generation will be settled based on the locational marginal price (LMP) of the resource node where the generator is located. Load will be settled based on a zone price that is a load-weighted average of the LMPs within the zone. The current 6 hubs which are the simple average of the LMPs within the hub bus will remain a basis for commercial trading. Financial instruments to hedge energy price risk will be implemented. The two planned instruments are Congestion Revenue Rights (CRR- auctioned by ERCOT monthly and annually) which offers the rights to the revenue stream from locational price differences (Transmission Congestion Price) and Contract For Differences (CFD non-ERCOT) which provides for hedging against price at a given location. Launch of the Texas Nodal market is expected in 2009.

SUMMARY

As a summary below are some of the observations from these other jurisdictions on how LMP supports the key elements for a good market design as it relates to impact on reliability, price discovery, equity among participants, subsidizing and uplifting of costs, gaming opportunities and economic efficiencies:

- By construction these are the prices that reinforce reliability by making the individual incentives for generators and loads reflect the requirements of reliability and system constraints.
- Provides for easier and more accurate management of congestion and more accurate unit information.
- Presents a basis to design forward congestion management procedures to be as consistent as possible with the real-time operating needs of the grid.
- Ensures that the cost of congestion is reflected in electricity prices and ensures that the least-cost supply of electricity is delivered while respecting the physical limitation of the transmission network.
- Improved dispatch efficiencies allows for dispatching of resources that will yield a lower overall cost of power supply.
- More granular pricing (improved and transparent) that should encourage additional generation and/or transmission investment in the proper locations.
- Provides more information on pricing possible alternatives for competitive wholesale electricity markets for example the value of demand response in a particular region.
- Identifies constraints and helps formulate cost effective transmission expansion projects – maybe a coordinated process to identify and pay for additional transmission capacity.
- Provides flexibility to adapt to changing conditions.
- Participants can readily determine areas of congestion and will see the value of investing in generation, transmission and demand response programs.
- LMP allows/supports fair, transparent and equitable regulations and market monitoring.
- Introduces market discipline and observable consequences of behaviour, minimizing opportunities for gaming and uplift - using any other pricing system would guarantee, by definition, that the resulting operating incentives for the market participants would be to behave in ways that are in conflict with reliability and the constraints on the system.
- Balances reliability and economics.

Together, the other ISOs examined in this paper operate regional security-constrained economic dispatches priced (or soon to be priced) at LMP for well over half the US interconnected grid and two thirds of all US electricity consumption. Transmission congestion is a reality for all and these ISOs collectively favour a locational pricing methodology for managing it.