PREDICTIVE OPERATIONS IN US POWER MARKETS

A discussion on locational marginal pricing (LMP) forecasting

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INTRODUCTION

Signs are emerging that North American power markets are moving toward commonality and maturity in their function if not their operations. Over 10 years after the Federal Energy Regulatory Commission (FERC) announced the Notice of Proposed Rulemaking (NOPR) on Standard Market Design (SMD), major US power markets now seem to have a foundation to voluntarily provide similar pricing granularity and hedging capabilities to their participants.

Two of the largest power markets, ERCOT and California markets, have now completed implementation of a “nodal”, or locational marginal pricing (LMP)-based market. With a successful transition of these markets to full LMP implementations (from the previously existing zonal market pricing structure), approximately 60% of the generating capacity in the United States will be operating within an RTO-centric LMP-based market environment. As a result, these markets will provide pricing so granular in terms of presentation, and complex in terms of derivation and/or calculation, that many consumers and market participants may choose not to directly participate, because both the risks and the information required to succeed might be beyond their reach.

However, other market players may see the transition as a major opportunity to identify risks and extract value. To fully benefit and reap these rewards, they will need accurate information and the ability to predict the potential impacts of proposed actions.

This whitepaper discusses the importance of having the data and tools to efficiently and effectively supporting predictive (as opposed to preventive) operations in an LMP-based market. It discusses the factors that complicate the problem, how different types of market participants are uniquely challenged, and how the diversity of their requirements drives the needs for a spectrum of solutions.

Advances in predictive operations

Improving the quality of market predictions hinges on improving planning, forecasting and optimization capabilities. In turn, these analytical activities are facilitated through the following (please refer to Figure 1):

- The availability of market information at increasing levels of granularity, enabling historical and predictive analysis of pricing and general market behavior
- The convergence of grid and information technologies to support intelligent or smart grid operations, which in turn provide the ability to monitor and respond to grid and market conditions in near real-time

Figure 1. Analytical elements of predictive operations
These capabilities are important to improving management of risks and margins in interactions with evolving power markets. More often than not, risky positions, and indeed risk itself, have resulted from poor data or improper application of good data. Further, in the past, once decisions were made their results were only predictable after the fact or at settlement time.

Today, the consequences of actions can be understood far more quickly. The availability of detailed information and advanced settlement practices, coupled with appropriate price forecasting techniques, provides an opportunity for quick assessment of real-time exposure, errors corrected, and new positions taken in the market.

The ultimate objective of many market participants is to push their prediction capabilities to near real-time. Meanwhile, regulators are carefully watching this process, as they will ultimately need the ability to manage and control such participant actions to limit market manipulation. Both of these efforts are continuing to drive the availability and sophistication of tools and data.

These issues are not new. Many market participants have been dealing with nodal power markets in PJM (Pennsylvania-New Jersey-Maryland), New York and New England for many years. The competencies they have developed will translate to advantage in the newer Texas and California markets. However, the sheer size and visibility of these two markets have exposed the need for greater forecasting capability and are challenging the infrastructure of the largest and most sophisticated players.

The progression to LMP markets
Power markets throughout the US have continued to reregulate and deregulate (liberalize) for more than a decade. Each market upgrade to this point has increased the granularity and transparency of the market itself. Major milestones in the development of LMP markets include:

- 1992 – Energy Policy Act. The primary federal agency behind the restructuring of electricity markets in the US continues to be the Federal Energy Regulatory Commission (FERC). Through the authoritative powers vested in it by the Environmental Protection Agency (EPA), FERC initiated the transition to competitive bulk energy markets in the US in a bid to ensure competitive practices and economic efficiencies in the wholesale electricity market.

- 1997 - PJM became the first association of interconnected electric systems, or power pool, to officially operate as a Regional Transmission Organizations/Independent System Operator (RTO/ISO). The largest centrally dispatched electricity system in the world1, PJM at the time was also the first North American market to implement LMP as a congestion-management mechanism. For the previous 25 years, PJM had centrally dispatched generation based on Security Constrained Economic Dispatch (SCED), with the economics determined by the embedded rate-based costs for the generating units.

- 1997 - New England (ISO-NE) is declared an ISO.


- 1999 – Order 2000. FERC mandated that all transmission facilities within the US be placed under the control of the various RTOs. Later in the year, FERC strengthened this rule by requiring all utilities participating in interstate commerce to become a member of an RTO. The need for and structure of such changes to North American electricity markets continue to be debated.


- 2003 – ISO-NE adopts an LMP pricing scheme as part of its transition to a so-called standard market design.

- 2005 - Mid-West ISO (MISO) becomes the first multistate RTO without a historical power pool
such as NYISO or PJM to implement a wholesale energy market with centralized economic dispatch and LMP pricing.

- 2009 - California ISO (CAISO) went live with a fully nodal LMP market. The Market Redesign and Technology Upgrade (MRTU) project established an LMP real-time market and a day-ahead market. This combination, known as the Integrated Forward Market (IFM), was designed to co-optimize energy, reserves and capacity, balancing supply and demand. The MRTU project also implemented a Full Network Model for the purposes of modeling the entire California transmission grid.

- 2010 - Electric Reliability Council of Texas (ERCOT) went live with a full nodal LMP market and day-ahead energy market.

In theory, LMP markets were designed to produce market price signals that would drive construction of either new generation or new transmission capacity. By definition, LMP is the cost associated with serving an incremental megawatt (MW) of demand at any particular location on the power system grid. LMPs contain cost elements for energy, losses and congestion. In the absence of any transmission system congestion, and if losses are ignored, LMPs are uniform throughout the system, as the congestion component is zero. However, this is a rare occurrence.

Figure 2 presents some historic data from the PJM system, which plots the three components (energy, losses and congestion) for a day. The first chart illustrates the contribution of the predicted congestion in the DAM. The second chart, illustrates the actual congestion prices as a component of the real-time prices. The congestion component in both cases is a significant factor, and in fact drives prices and price differentials in real-time.
The obvious volatility of these markets provides both opportunities for gain and the risk of significant financial loss. Table 1, gathered from publicly available information, illustrates the growth of LMP markets in North America.

Table 1. LMP North American Market Growth

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<tr>
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<th></th>
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</thead>
<tbody>
<tr>
<td>PJM</td>
<td>1997</td>
<td>145</td>
<td>165</td>
<td>$22 Billion</td>
</tr>
<tr>
<td>ISO New England</td>
<td>2003</td>
<td>28</td>
<td>32</td>
<td>$9 Billion</td>
</tr>
<tr>
<td>NYISO</td>
<td>2004</td>
<td>34</td>
<td>44</td>
<td>$11 Billion</td>
</tr>
<tr>
<td>MISO</td>
<td>2005</td>
<td>116</td>
<td>156</td>
<td>$29 Billion</td>
</tr>
<tr>
<td>CALISO</td>
<td>2009</td>
<td>50</td>
<td>55</td>
<td>$13 Billion</td>
</tr>
<tr>
<td>ERCOT</td>
<td>2010</td>
<td>62</td>
<td>72</td>
<td>$30 Billion</td>
</tr>
<tr>
<td>SPP</td>
<td>TBD</td>
<td>42</td>
<td>45</td>
<td>$15 Billion</td>
</tr>
<tr>
<td>NODAL</td>
<td>478</td>
<td>569</td>
<td></td>
<td>$129 Billion</td>
</tr>
<tr>
<td>US</td>
<td>789</td>
<td>1076</td>
<td></td>
<td>$325 Billion</td>
</tr>
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</table>

In 2009 approximately 60% of US capacity was operating under LMP-based markets. Understanding key drivers of the LMP markets and forecasting the resulting pricing trends is considered vitally important to the success of many market participants. As LMP based markets become standard, it will be increasingly important for market participants, regulatory authorities and energy traders alike to equip themselves with price forecasting knowledge and tools to aid decision making and policy judgments. Unfortunately, power market operations are a complicated balance of physics and economics. As a result, LMP-based nodal power markets are different from other energy markets or from market structures associated with other commodities. One of the key aspects that differentiate the LMP-based nodal power markets from markets for other commodities, is the lack of a financially feasible large scale energy storage option thereby necessitating the balance between supply and demand in real time.

The LMP calculation is based on the power flow solution for the system under consideration. Accurate representation of the physical grid, generation and load is needed to represent the entire power system network.

The familiar network model is a major component of this representation. Forms of these network models have been in existence for many years and are historically the domain of system operations, power systems engineering, operations planning and transmission planning. Much of the knowledge of the content of these models is institutional and remains even today with the owner of the asset. The full emergence of LMP-based markets is driving this data into the public domain as an accurate model is essential to realizing the economics of the system. For a successful, liquid and fungible market, power system economics require consistency between the various foundational elements used in pricing forward and real-time markets for congestion, energy and ancillary services. The network model is the price-calculation foundation for all of these markets.

In addition to the network model, the LMP at any given location within a system is sensitive to a host of variables, some of which can be accurately modeled and others simply estimated. Most of the modeled parameters require frequent updates, and most of the information is not currently centrally available. Further, as the smart-grid initiatives are implementing more and more intelligent network devices, the challenge to maintain the network models in a “current” state, and calibrate these dynamic devices, may seem daunting to many organizations.

The processes and infrastructure required for the provision and maintenance of data required for
accurate pricing modeling may be as complex as the modeling itself. Because of this, a careful analysis of business needs is recommended before expending funds and effort on the creation of the capabilities to provide reliable market simulations. “The internal solution” may not necessarily be the optimal solution for your organization.

**Business need-based problem definitions**

In each market, an organization’s business operations should match the sophistication of the solution chosen to predict behavior in each market. However, in reality, the standard forecasting practices of a given market participant often do not match its maturity in that market. More often than not price forecasting is a business function in which the results used in analysis and decision support are “good enough.” A review of intrinsic, basic power operations and functions clearly illustrates their dependence on price forecasting.

**Transmission Operations**

The use of transmission forecasting for grid planning and operation is a traditional utility function. Although in North America the ownership and management of the transmission system is still tightly regulated, a number of merchant projects are being considered or are already under development. The primary uses of LMP or price forecasting by a transmission owner or operator such as an ISO or other central market operator are:

1. **Transmission planning:** Market models are prepared to evaluate the magnitude and patterns of congestion in a system. This helps the planner understand where relief may be needed and then enables the transmission owner to determine the best method for project financing and investment recovery. Transmission planning can have both long- and short-term aspects, which will drive the form of the forecasting being developed. Some traditional functions of the electric utility are accomplished with the form of network model known as the “planning model.” This is the primary network model that is or will be used in the performance of yearly auctions for congestion-based products such as the Congestion Revenue Rights in ERCOT, California and PJM. It is also the model used in determining the viability of any merchant projects, providing an estimate of congestion cost reduction in the system and hence the potential for cost recovery of the merchant line.

2. **Grid operations:** Today the “network operations model” is the fundamental model for real-time calculation of LMPs and base points for generator dispatch. Day-ahead and hour-ahead forms of this model provide the initial set of prices, base points and shadow prices from which most resource commitments are confirmed. At this point the model is still just an estimated state of the grid and other systems. The actual “operating” model is updated continuously using real-time information obtained through telemetry and a state estimator to enable the calculation of real-time pricing. All forecasting models try to simulate the network operations model for real-time operations.

**General Operations**

From an economic standpoint, generator owners are at risk for finding a buyer for their power and obtaining sales value that covers power production costs. The converse is also true. A generator should be able to offer power at a price that has value to the taker. In an LMP market, both of these factors are dependent on the physical location of the generator. These facts drive several forecasting needs for the owner/operator of generation:

1. **Project sighting** – Typically, market models are prepared to indicate the price range for the desired location based on known outages and other planned projects (transmission and generation) at least two to five years from operations, and in some cases as many as fifteen for nuclear projects. The forecasting of these models is best described as an accurate crystal ball technique. All the available information is put into the model with the hope that reality checks out somewhere close. In such cases, although some level of pricing granularity is
helpful, it is doubtful that the actual values generated from a 24/7 dispatch with 15-minute pricing intervals is really necessary. However, the project developer should be able to predict likely transmission constraints around planned generating facilities, as well as gauge its own cost of production.

2. Operations – Once the plant(s) are operational, the primary goal of most fleet owners is the optimization of the plant portfolio using a bidding strategy that maximizes revenue for the fleet. With LMP markets, most fleets are controlled by the central market authority or an ISO/RTO. LMP forecasting for these plants now becomes more important, as it can provide guidance for how these units are bid into the market and thus how they are chosen to operate. Although most markets support some level of cost-based guarantee payments for system-needed generation, generation bids at the margin are most likely to be market based.

Retail Operations

A load serving entity or retail provider must source just enough power to fulfill its contractual obligations to its customers, at a price that enables it to cover its required operating costs and fulfill earnings obligations to its investors/owners. From a price forecasting perspective, the types of solutions required are proportional to the sophistication of the following two functions:

1. Supply management functions – The more sophisticated a product purchased on the wholesale market the more sophisticated the forecasting solution needs to be. Retailers may choose to simplify this function and simply buy the power at their door, minimizing the risk of congestions costs. Or, they may choose to manage the transportation of the energy and expose themselves to a greater degree of price uncertainty.

2. Customer contracts – If retail deals are flexible, perhaps even indexed to forward markets, the forecasting solution will need to provide an understanding of ongoing risks throughout the life of the contract. At the time of contract signing, forecasting capability will be needed to evaluate how supply side flexibility can accommodate the contract and thus calculate a pricing scenario. If customers are receiving a simply priced retail product, such as simple flat rates, forecasting requirements are also simplified.

Power Marketing

Trading of power, ancillary services and congestion products typically presents the most varied and rigorous demands for price forecasting. Often, the “marketers” are among the most sophisticated players in the power and gas markets. Traditional “traders” are now teaming with commodity brokers, or the trading function is an arm of the investment community. Power trading has become part of the fabric of many financial institutions.

Traders are now active in all of the forward markets, they often might have specific asset deals that provide a base load to trade, and in many cases they are beginning to speculate in the congestion markets. Specific requirements for LMP forecasting by a trader may include all of those previously described, plus more deal related activities such as deal evaluation and monitoring, hedge assessments and acquisition, and position calculation and monitoring.

Solution options

Requirements for developing an appropriate solution can be categorized as long-range studies, short-term decision support and day-of transaction support:

Long-range studies – two months to five years (crystal-ball operations)

• Congestion revenue rights (CRR) yearly auctions and allocations
• Transmission and generation asset valuation, purchase or planning
• Basis swaps and other long-term bilateral financial deals
• Power purchase agreements
• Load participation
Short-term decision support – under-a-month to day-ahead

- CRR monthly auctions and auction reruns
- Day-ahead and hour-ahead markets (CRRs, ancillary services and energy)
- Power purchases and sales
- Support for cross commodity transactions

Day-of transaction support – day ahead to real-time (predictive operations)

- Hour-ahead scheduling (where supported)
- Bid optimization and ancillary service provision
- Emergency purchase decision support

The targeted solution should be driven by an assessment of where the business needs to be on a spectrum of solutions. These solutions range from no solution to an almost-real-time solution that simulates operations of the actual market in which business is being conducted.

The type of solution used will depend on the type of operations being supported – long term, real time or somewhere in the middle. For example, a Load Serving Entity (LSE) that simply wishes to cover its load requirements by purchasing energy within a load zone does not need to simulate the entire network. Instead, it need only understand historical pricing patterns, congestion patterns and outage information.

On the other hand, a utility with generation and load may want the ability to predict each pricing point within the network in order to fully optimize profits. This would require some degree of sophistication in modeling tools and forecast engines, as well as the ability to slice, dice and report on the data that may be needed in real time.

Figure 3 illustrates the varying levels of solution detail and accuracy needed for real-time predictive operations:
Risk evaluation is the final step in developing “the solution.” With risk appetite as the fundamental driver behind the sophistication of a forecasting solution, several questions need to be addressed:

1. What level of forecasting accuracy is needed?
2. What mechanisms are being used to validate the forecast results and establish the risk parameters?
3. Is there value in using a model versus the similar-day approach currently being used in several applications?

**What is the accuracy of the forecast?**

In the past, forecasting of monthly trends for zones or markets may have been adequate for most purposes. However today’s risk and congestion management practices demand some form of nodal price simulation. In addition, depending on the purpose, it is now popular to run models and develop a solution for every hour and for every month for the years under consideration, even for long-range studies. Does this in fact make sense to do?

In many organizations, the data is probably not as accurate or as relevant as hoped, for several reasons. It is not easy to accurately forecast market results. Physical and market variables are too numerous. Power is not truly a commodity, as it is currently bound to its “shipping lanes” and cannot be effectively stored. There are many elements still being predicted from long range, including weather, outages, resource availability, fuel prices and other required commodities, network models, and load.

At long range, this means that a given hour’s values are perhaps merely speculation. Educated speculation to be sure, but actually it is simply an estimate.

The risk of basing future business decisions on such information should be clearly documented. A major element of risk analysis, both before action and post mortem, is an assessment of the process that was followed to maintain the currency, validity and accuracy of the data and model. This particular aspect of forecasting is almost always overlooked until the iceberg has been hit.

Further, as the estimation “model” grows more sophisticated and moves into the realm of day-of decision support, the amount of data needed to feed the model and the demand for accuracy

![Figure 4. Model automation and visualization](image-url)
expand dramatically. At this point, automation of most data feeds is needed, as well as perhaps some form of data warehouse and a GUI/visualization layer to permit analysis in a near-real-time mode. Figure 4 illustrates such a solution.

**How is the forecast validated?**

This is the simplest question of all. Whatever model or mechanism is chosen for forecasting, a mechanism is needed to validate results. This procedure, typically known as a back-cast, should include a validation of both results and conditions used in obtaining the results. It should include comparisons with forward curves and historical data, as well as the actual operation of the market under simulation. The right validation method typically leads to a degree of repeatability and perhaps more confidence in results. From a risk perspective, successful validation of predicted behaviors is essential in determining the usability of a forecasting process. Without validation, the results may not be reliable enough to make sound business decision.

**What is the value of using a model?**

Today, even in long-range forecasting, there is a growing expectation that the forecaster is using a model with some stochastic mechanism that provides both values and probabilities. This expectation is driving considerable discussion of whether development of highly sophisticated internal capabilities is actually required. Does the business really need to expend so much effort and money in this area to be successful?

For most businesses, the correct answer to this question is surprisingly no, assuming all goes well and appropriate business decisions are made.

However, the level of financial exposure in most power markets is considerable. And, as with all things human, the concern is with exposure and risk of errors in whatever process is chosen. Whether the capability is outsourced or internal, the overriding issue in power markets is the level of volatility experienced. Using a model and associated processes of some form permits more accurate risk assessment and implementation of appropriate business hedges at a lower premium.

**Conclusion**

Operating in real-time in today’s markets requires a level of sophistication in tools and data management that most market participants normally do not reach. Moving into the realm of predictive operations requires major investments in infrastructure and people, as well as substantial internal change.

A range of solutions are available, with one or more choices appropriate for most market participants. The trend toward sophistication in forecasting solutions is primarily driven by how much risk an organization seeks to mitigate. Justifiable cost-benefit calculations may be hard to achieve or demonstrate unless a broken capability or human error has already produced a measurable financial loss. The costs of the infrastructure and processes required to fully implement a “predictive solution” may well point to outsourcing some or all of the capabilities, particularly if requirements are intermittent.

In conclusion, market forecasting is simply that. The prices developed are a forecast. Consider values as indicative of pricing trends and behaviors. Do not consider them too literally, and hedge dealings as effectively as possible.

**References**


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