Signs are emerging that North American power markets are moving toward commonality and maturity in their function, if not their operations. More than ten years after the Federal Energy Regulatory Commission (FERC) announced its Notice of Proposed Rulemaking (NOPR) on standard market design (SMD), major U.S. power markets now seem to have a basis on which to voluntarily provide similar pricing granularity and hedging capabilities to their participants.

Two of the largest power markets, the Electric Reliability Council of Texas (ERCOT) and the California market, have now completed implementation of a “nodal” market: one based on locational marginal pricing or the locational marginal price (LMP) of energy. With a successful transition of these markets to full LMP implementations, approximately 60% of the generating capacity in the United States is operating within an LMP-based market. As a result, these markets will provide pricing so granular and volatile that
many consumers and market participants may choose not to participate directly, because the information required to analyze the risks and succeed is probably beyond their reach.

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

This article discusses the importance of having the data and tools that are often critical in efficiently and effectively supporting predictive operations in an LMP-based market. It discusses the factors that complicate the problem, how different types of market participants face unique challenges, and how the diversity of their requirements drives the need 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 (see Figure 1), these analytical activities are facilitated through:

✔ 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.

These capabilities are important to improving the management of risks and margins in interactions with evolving power markets. More often than not, risky positions—and indeed, risks themselves—have resulted from poor data or the improper application of good data. And 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, the correction of errors, and the taking of new market positions.

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.

figure 1. Analytical elements of predictive operations.
Power markets throughout the United States have continued to reregulate and deregulate (liberalize) for more than a decade.

These issues are not new. Many market participants have been dealing with nodal power markets in Pennsylvania–New Jersey–Maryland (PJM), New York, and New England for several years. The competencies they have developed will now translate to an advantage in the Texas and California markets. The sheer size and visibility of these two markets, however, 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 United States 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 the following:

- **1992**: The Energy Policy Act is passed. Although the primary federal agency behind the restructuring of electricity markets in the United States continues to be the FERC, through the authoritative powers vested in it by the Environmental Protection Agency (EPA), FERC initiates the transition to competitive bulk energy markets in the United States in a bid to ensure competitive practices and economic efficiencies in the wholesale electricity market.
- **April 1997**: PJM becomes the first association of interconnected electric systems, or power pool, to officially operate as a regional transmission organization and independent system operator (RTO/ISO). The largest centrally dispatched electricity system in the world, 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.
- **July 1997**: New England (ISO-NE) is declared an ISO.
- **July 1999**: ISO-NE implements wholesale energy markets.
- **December 1999**: With Order 2000, FERC mandates that all transmission facilities within the United States be placed under the control of the various RTOs. Later in the year, FERC strengthens this rule by requiring all utilities participating in interstate commerce to become members 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 scheme as part of its transition to a so-called SMD.
- **April 2005**: Mid-West ISO (MISO) becomes the first multistate RTO without a historical power pool like the ones NYISO and PJM had to implement a wholesale energy market with centralized economic dispatch and LMP.
- **1 April 2009**: California ISO (CAISO) goes live with a fully nodal LMP market. The Market Redesign and Technology Upgrade (MRTU) project establishes an LMP real-time market and a day-ahead market (DAM). This combination, known as the Integrated Forward Market (IFM), is designed to cooptimize energy, reserves, and capacity, balancing supply and demand. The MRTU project also implements a full network model for the purposes of modeling the entire California transmission grid.
- **December 2010**: ERCOT goes live with a fully nodal LMP market and DAM.

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, the LMP is the cost associated with serving an incremental megawatt 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. This is a rare occurrence, however.

Figure 2 presents some historical data from the PJM system that plots the three components (energy, losses, and congestion) for a single day. Figure 2(a) illustrates the contribution of the predicted congestion in the DAM. Figure 2(b) 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 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.
In 2009, approximately 60% of U.S. capacity was operating under LMP-based markets. Understanding the key drivers of the LMP markets and forecasting the resulting pricing trends are 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 guide 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 and from the market structures associated with many other commodities.

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. 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 about 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 these 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 among 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 while others must be estimated. Most of the modeled parameters require frequent updates, and most of the information is not currently centrally available. Further, as smart grid initiatives place more and more intelligent network devices in service, the

### Figure 2. LMP cost elements in (a) the DAM and (b) the real-time market.

### Table 1. LMP North American market growth.

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<tr>
<td>PJM</td>
<td>1997</td>
<td>145</td>
<td>165</td>
<td>US$22 Billion</td>
</tr>
<tr>
<td>ISO New England</td>
<td>2003</td>
<td>28</td>
<td>32</td>
<td>US$9 Billion</td>
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<td>NYISO</td>
<td>2004</td>
<td>34</td>
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<td>MISO</td>
<td>2005</td>
<td>116</td>
<td>156</td>
<td>US$29 Billion</td>
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<tr>
<td>CALISO</td>
<td>2009</td>
<td>50</td>
<td>55</td>
<td>US$13 Billion</td>
</tr>
<tr>
<td>ERCOT</td>
<td>2010</td>
<td>62</td>
<td>72</td>
<td>US$30 Billion</td>
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<td>SPP</td>
<td>TBD</td>
<td>42</td>
<td>45</td>
<td>US$15 Billion</td>
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<tr>
<td>NODAL</td>
<td>478</td>
<td>569</td>
<td></td>
<td>US$129 Billion</td>
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<tr>
<td>United States</td>
<td>789</td>
<td>1,076</td>
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<td>US$325 Billion</td>
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challenge of maintaining the network models in a “current” state may seem daunting to many organizations.

The processes and infrastructure required for the provision and maintenance of the data required for accurate pricing modeling may be as complex as the modeling itself. Because of this complexity, a careful analysis of business needs is recommended before expending funds and effort to develop the capability to provide reliable market simulations. “The internal solution” may not be required in every 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 that market. In reality, however, 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 for 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 for 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.” Variations of this primary network model are used in the yearly auctions for congestion-based products such as the congestion revenue rights (CRRs) traded in ERCOT, the California market, and PJM. It is also the model used in determining the viability of any merchant projects: it provides 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.

**Generation Operations**

From an economic standpoint, generator owners are at risk for finding a buyer for their power and obtaining a 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 various forecasting needs for owners and operators of generation, as follows:

1) **Project siting:** 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 15 years out 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 whether the actual values generated from a 24/7 dispatch with 15-min pricing intervals are really necessary. The project developer should, however, be able to predict likely transmission constraints around planned generating facilities, as well as gauge its own cost of production.

2) **Operations:** Once a plant is 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 RTO/ISO. 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 guaranteed payments for system-needed generation, generation bids at the margin will probably 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 its earnings obligations to its investors and 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 is, the more sophisticated the forecasting solution needs to be. Retailers may choose to simplify this function and by buying the power at their door, minimizing the risk of congestion 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**

The trading of power, ancillary services, and congestion products typically presents the most varied and rigorous demands for price forecasting. Often the current “market-ers” are among the most sophisticated players in the power and gas markets. Traditional “traders” are now teaming up 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 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 described above, plus activities that are more deal related, such as deal evaluation and monitoring, hedge assessments and acquisition, and position calculation and monitoring.

**Solution Options**

The requirements for developing an appropriate solution can be divided into three categories: long-range studies, short-term decision support, and day-of-transaction support. These categories can be further subdivided as follows.

1) **Long-range studies** (two months to five years—“crystal ball” operations) include:
   - annual CRR auctions and allocations
   - transmission and generation asset valuation, purchase, and planning

   ![figure 3. The predictive operations maturity curve.](image-url)
basis swaps and other long-term bilateral financial deals
- power purchase agreements
- load participation.

2) Short-term decision support (under a month to day-ahead) includes:
- 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.

3) Day-of transaction support (day-ahead to real-time) predictive operations include:
- hour-ahead scheduling (where supported)
- bid optimization and ancillary service provision
- emergency purchase decision support.

The choice of a 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 a nearly real-time solution that simulates the operations of the actual market in which business is being conducted.

The type of solution adopted 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 only needs to 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 its 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:

✔ What level of forecasting accuracy is needed?
✔ What mechanisms are being used to validate the forecast results and establish the risk parameters?
✔ 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. Today’s risk and congestion management practices, however, 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?

In many organizations, the data are probably not as accurate or as relevant as had been hoped. This is true for several reasons. It is not easy to forecast market results accurately. The 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 stored effectively. There are many elements still being predicted at long range, including weather, outages, resource availability, fuel prices and the cost of other required commodities, network models, and load.

![Figure 4](image)

**Figure 4.** Model automation and visualization.
At long range, this means that a given hour’s values are, perhaps, merely speculation—educated speculation, to be sure, but in reality 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 postmortem, 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 expand dramatically. At this point, the automation of most data feeds is needed, and perhaps some form of data warehouse and a graphic user interface (GUI) visualization layer to permit analysis in a nearly real-time mode as well. 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 backcast, should include a validation of both the forecast results and the 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, what tool was used or how accurate the data were is irrelevant. The results should not be used to make long-term or day-of business decisions.

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 of some stochastic mechanism that provides both values and result probabilities. This expectation is driving considerable discussion about whether the 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. The benefits do not typically justify the costs, assuming all goes well and appropriate business decisions are made.

The level of financial exposure in most power markets is considerable, however. And, as with all things human, the concern is with exposure and the 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 its associated processes permits more accurate risk assessment and the 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 is available. One or more of the choices will be 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 take them too literally, and hedge dealings as effectively as possible.

For Further Reading


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