Considerations for the Design of Restructured Electricity Markets and Institutions

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Abstract

Over the last decade there has been significant interest in opening the electricity sector to competition and, by extension, interest in designing electricity markets to push the sector toward more efficient outcomes. However, for either political or structural reasons competition has been implemented only in a few places and with mixed success. Hence, the extent to which competition is feasible or desirable in a sector that has traditionally been vertically integrated and highly regulated or state-owned has been questioned. Still, regardless of the design of electricity sector reform, the ultimate goal of reform is to make the sector more efficient.

This paper provides an overview of concepts that regulators must understand and questions regulators must ask and eventually answer, regardless of the kinds of reforms undertaken, so that regulators can act as catalysts for reform and efficiency improvements. Among these are an understanding of system operation and how different market models are directly related to system operation, since electricity markets are closely linked to system operation, regardless of the model chosen,. Additionally, this paper outlines the legal and regulatory concepts that affect sector performance, such as reliability, demand-side response, consumer protection, and that must be accounted for when undertaking reform. The paper concludes with a short, stylized outline for implementing reforms, including the establishment of new institutions and the staffing of those institutions.

Introduction

There has been a great push toward reforming the electricity sector around the world over the last ten-plus years. The type of reform varies from corporatizing and regulating state-owned electricity companies, as in South Africa, to introducing various forms of competition in generation, as in Chile, Argentina, the United Kingdom, and the United States. The success of competition in its various forms has been mixed at best.

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For example, the implosion of the markets in California has led many countries to rethink the use of competitive mechanisms or to try to tightly manage competition.

Reform has also led to the formation of regulatory agencies where none existed previously and to rapidly changing thinking about how regulation can increase incentives for outstanding performance and efficiency improvements. Chief among the changes in how regulators do their job is the movement toward so-called "incentive regulation," regulation mechanisms such as price caps, revenue caps, and profit- or revenue-sharing mechanisms. These types of reforms have been considered by many to be much more successful than the introduction of competition in generation, as there seems to have been greater efficiency gains in those parts of the electricity market subject to incentive regulation.

The Need to Understand Industry Operation

Regardless of whether the reforms being implemented include only incentive regulation or include a movement toward competition in generation, it is absolutely essential for regulators and regulatory staff to understand how the electricity system operates and the technology being used. Without an understanding of day-to-day system operation such as production and maintenance processes, a regulator will have great difficulty understanding the historical cost structure and assessing how much more efficient the utility can become. Without this knowledge, the cost numbers a utility presents to a regulator have no context.

Moreover, if the reform being considered envisions some kind of market for generation, it is imperative that the regulator understand the details of system operation, including concepts of unit commitment, dispatch, contingency constraints, and transmission congestion management. All of these can have an impact on the outcomes of a market for generation. All of these concepts have implications for the cost of service in a fully regulated environment. Also, an understanding of these concepts will allow a regulator to ask the right questions about how a generation market is designed and to avoid the mistakes already made in markets such as California or England and Wales.

The Need to Consider Regulatory and Legal Concepts

Power sector reforms may be driven by the ideas of efficiency improvements and cost savings, but reforms must also consider more traditional legal and regulatory concepts and how these affect the success of reform. Ideas about reliability, consumer protections, public benefits, creditworthiness, and facility siting, among others, can affect the ability of reforms to achieve their objectives. Consideration of these more traditional regulatory concepts in the context of the reform being considered are just as important as an understanding of system operation. Depending on how these concepts are applied, they will have significant impacts on incentives for existing utilities and on potential new entrants into the sector. Moreover, if the application of these traditional regulatory ideas is done poorly, it can create incentives that run counter to the objectives that reform strives to achieve.

Structure of the Paper

I first outline concepts of system operation. These are important regardless of the structure of reform in that they can tell a regulator a lot about how efficiently the system is being run in the short term and can give the regulator an idea about how the system ought to be configured in the long term. This information can also provide the regulator with a baseline for regulating generation and transmission usage prices as necessary. Following the discussion of system operation is a list of concepts and questions that a regulator should ask if reform includes a move toward competition in generation. It should be noted up front that these concepts and questions are intimately related to system operation. Next, the various regulatory and legal concepts that must be considered in the reform are outlined. A short explanation of each concept is given along with its relevance to reform that is highly regulated and reform that envisions competition in generation. I conclude with an implementation outline.

System Operation

System operation centers on the utility's ability to commit generation in advance and dispatch these resources in real time at the least cost, subject to generator and transmission constraints. In particular, it is imperative to determine whether the dispatch and unit commitment protocols are entirely pre-programmed algorithms or whether the protocols are more heuristic (based on the system operator's familiarity with the system). The latter may not lead to least-cost commitment and dispatch of generator resources since the protocol is not pre-programmed.

1. *Security Constrained Unit Commitment (SCUC).* This is the protocol by which the utility commits units to run in advance of the actual dispatch time. This should minimize costs associated with system operation, subject to physical constraints on generators and physical limitations of the transmission system. SCUC is important in that some types of generating units cannot be immediately started up and require long lead times to be synchronized to the grid. Questions a regulator should have answers to are listed below.
    a. Does the system operator have all necessary cost and technical data to perform the SCUC in a pre-programmed fashion?
    b. Are start-up costs, minimum load costs, start-up times, ramp rates, and other generator-specific constraints accounted for explicitly in the SCUC? If these are not accounted for, the system operator must run with more "slack" in the system. Moreover, not including start-up and minimum load costs is not a minimization of all costs.
    c. How are transmission constraints included in the SCUC? How much capacity is being left on lines to account for contingencies? Is this too much or too little? Too much space on the lines leads to higher commitment and dispatch costs. Too little, and reliability is at risk.
    d. Is the SCUC solved by approximation techniques such as Lagrangian Relaxation or solved to optimality with integer-programming techniques? Solving by approximation techniques can lead to deviations from least-cost, although these may not be large.

e. What is the time horizon for the SCUC? SCUC can be done anywhere from a day ahead of dispatch to a week ahead of dispatch.
f. How is the system lambda determined in the SCUC for each hour? This is similar to a market-clearing price in that the system lambda is the marginal cost of producing one more megawatt of power. If not done properly, this can lead to a deviation from the least-cost dispatch by running units that are more expensive than necessary.
g. What contingencies are accounted for in the SCUC? These contingencies can include the loss of a generator or transmission facility. The more contingencies that are included, the more likely it is that the commitment and dispatch are more expensive.

2. *Security Constrained Dispatch (SCD).* This is the actual real-time dispatch of generation to meet load based on the SCUC. Many of the same questions asked under SCUC can be asked here.
    a. Does the system operator have all necessary cost and technical data to perform the SCD?
    b. How often are dispatch signals sent to generators? In many systems, signals are sent every five minutes.
    c. How is the system lambda (pool price) determined in each dispatch interval?
    d. Do pool prices change during each dispatch interval in real time?
    e. What contingencies are accounted for in the SCD?

3. *System Security (Contingency) Constraints.* These usually refer to transmission constraints (voltage and thermal limits) and the largest contingency the system must handle so as not to collapse.
    a. Can the system contingency constraints be relaxed to enhance the potential for electricity flows from the lowest cost generators?
    b. Do the system security constraints provide enough reliability?
    c. What are the cost impacts of the contingency constraints?

4. *Current Pricing Protocols for Transmission Constraints.* This is also known as congestion management. Usually, as a part of the SCUC or SCD, the program performing the problem does have information regarding transmission constraints and their cost to the system.
    a. If transmission constraints are binding, is this reflected in “prices” paid by load? That is, in a load area with binding transmission constraints (congestion), does moving power into that area cost more since the load is causing a transmission bottleneck? If not, there is an implicit cross-subsidy from consumers outside this area to consumers inside the area.
    b. If there is a pricing differential between areas, is this a nodal (bus) price or are prices done by zone (collection of busses)? By a bus or node, we mean a particular point in the system. When nodes are aggregated into zones, transmission congestion in a zone still leads to an implicit cross-subsidy, but it is now confined within the zone.

5. *Dispatch of Ancillary Services.* Ancillary services refer to those provided by generators (or other facilities) to help maintain system stability and integrity and to help in reliable operation. For example, ancillary services include different types of reserves to meet system contingencies, frequency response and control, and voltage support to move power on the system. Without these services, the delivery of real power to customers is jeopardized.
    a. Is ancillary service provision optimized separately from energy provision in the SCUC and SCD, or are energy and ancillary service optimized jointly? Optimizing these services all together will lead to an overall least-cost solution to provide electricity service to customers.
    b. How are generator costs determined for ancillary services by the system operator? This is important as some services do have real costs in terms of fuel costs and in terms of forgone power generation in units that are providing reserves or voltage support.
    c. Does ancillary service provision account for potential substitutability between types of services? This is another key that is not thought about enough. Many services, in particular, reserve services have a substitutability that can allow the system operator to minimize cost even further.
    d. Does the least-cost evaluation of ancillary service provision account for the cost of capacity only or for capacity plus energy if the generator is called on? Since what is really being offered with ancillary services, especially reserves, is the spare capacity, it is the capacity cost of providing the service that should be accounted for. This may be the opportunity cost of not running the unit for real power to serve customers. If a contingency does occur, the system operator should look at the running cost of the units set aside for reserves.

6. *Treatment of Must-Run Units.* Many systems have generating units that will always be dispatched in spite of being very expensive. This can occur because of long-term contract provisions or for reliability considerations. If the need to run these kinds of units can be eliminated, it can lead to lower operational costs.
    a. If there exist must-run units, are they taken as given in the dispatch? That is, because they will run no matter what, their cost is considered irrelevant.
    b. If there exist must-run units, are they allowed to set the system lambda? This is a little more important. If the most expensive unit is allowed to set system lambda (marginal cost of dispatching one more megawatt), and there are other less expensive units that could be run, there is the potential for aggravating the deviation from a least-cost dispatch, depending on the system used to dispatch units in real time.
    c. If there exist must-run units and they are not part of the least-cost dispatch, how are they compensated? This is interesting. If must-run units are being used to alleviate transmission congestion or a local reliability problem, they should be compensated by the area the unit is serving directly, and the cost should not be subsidized by the rest of the system that is not a part

of the problem. A follow-up question is whether there is a cheaper way of dealing with the need for the must-run unit, e.g. a transmission upgrade.

Regulatory and Legal Concepts

When electricity is provided primarily by vertically integrated monopoly companies, the regulator is responsible for assuring that retail rates are fair and reasonable, that service quality is sufficiently high, and that certain social goals, as deemed appropriate by government, are carried out through the rate structure. For recently established regulators, these responsibilities are relatively new, and the introduction of competition in generation gives rise to additional regulatory responsibilities. In either case, there is a need for skill sets within the regulatory body to assure that reform and/or competition achieves its goals and that all parties benefit during and after the transition to the new regulatory regime. The regulatory and legal framework must address all aspects of responsibilities relevant to competitive entry, regulation, and market oversight associated with a reform and/or competition in generation. The following listing indicates the range of issues in need of consideration and resolution.

Independence of Market and System Operators from Market Participants

The new legal framework will have to determine the degree of independence market and system operators will have from market participants in any regime with competition in generation. This can be a delicate balancing act. Allowing market participants to have some input into how the market and system are operated may be considered part of a good stakeholder process; however, if one participant or group of participants gains too much influence over the market and system operator, they may have an advantage at the expense of consumers and other market participants.

Creditworthiness of Market Participants

A legal and regulatory structure that requires all market participants to be financially sound means that financial obligations can be met. Without such a requirement, market participants may have an incentive to shirk their financial obligations, which can have a chilling effect on market participation and activity.

In a regulated environment some customers may be a risk to the utility serving them. If bills cannot be collected, reform attempts are unlikely to succeed. Moreover, if the reform includes privatizing existing assets, there must be some assurance that bills can be collected; otherwise, private companies may not see the sector as particularly inviting. For state-owned companies, this could be the difference between being financially dependent on government and being financially viable on its own.

Licensing Requirements for Market Participants

The purpose of creating a competitive market in generation is to allow market forces to determine how scarce economic resources should be allocated. In addition, where markets can be effectively competitive, new entrants can offer competitive alternatives to assure that costs do not become excessive. Yet, regulators may decide to license new market participants over a variety of dimensions, including creditworthiness, ability to deliver, service quality and reliability, and market conduct.

Power Plant Siting

An essential element of a competitive market in generation is that there be no, or at least few, barriers to entry. Laws and regulations pertaining to siting power plants present potential barriers to entry. Consistent with environmental and reliability objectives, siting laws must not be unduly burdensome and should apply equally to all generation providers. Preferably, the siting process is integrated into the regulator's responsibilities associated with assuring system reliability. If generation remains regulated, a long and drawn out process can add to costs unnecessarily and can lead to siting decisions that are not optimal from a system operation perspective.

Transmission Interconnection

With the introduction of independent power producers (IPPs) and potential new loads on a system, it will be necessary to investigate interconnection policies for these new generators and loads. The interconnection policy will need to address system reliability issues as well as the allocation of costs for interconnection. Great care will be necessary so that the interconnection policy does not create a barrier to entry into the market if there is competition in generation, and the policy must also account for system operation considerations. New load or generation should not be interconnected if existing transmission constraints will be exacerbated.

Transmission Infrastructure Siting

Adequate transmission capacity is required for competitive markets in generation or regulated system operation to function effectively. The inability to add transmission capacity to the system may unintentionally create barriers to entry into some areas, in the case of a market for generation, because of the inability to move power from one place to another. The same holds true in a regulated environment. Siting transmission lines can be part of an integrated planning process for reform while maintaining reliability at the lowest cost, consistent with environmental.

Reliability – Adequate Generation Capacity

When the electric distribution companies in a market are regulated, the regulator has the opportunity to supervise the reliability of the system by requiring distribution companies to secure adequate energy resources to serve customers. The regulator must establish reliability measures, such as reserve margin or loss of load probability. The process by which these reliability measures can be satisfied can either be market-driven or administratively determined. Ongoing reporting by load-serving distribution companies and close supervision by the regulator or system operator will detect instances when reserves become too low, thus endangering system reliability. But the regulator must keep in mind that there is a trade-off between reliability and cost of service to customers.

Reliability – Operational Security

Operational standards for all industry participants are another facet of electric system reliability. Adherence to a common and legally enforceable protocol for operation of the bulk power system will increase the reliability of the system and enhance conditions for effective competition if it is desired. The role of the regulator is to

establish and enforce reliability standards. Recent events in the United States show what can happen when there are no legally enforceable reliability standards.

Integrated Resource Planning

Even when there is a competitive wholesale market for electricity, the market does not become "deregulated." A restructured market (and the restructuring process itself) will rely on the regulator in many ways. Market forces may provide the best outcomes for minimizing costs of generating resources, and may be involved on the demand side as well in allocating scarce resources, but there remain elements of system planning that require the involvement of the regulator. In the event of market failure, the regulator will need to determine whether generation, transmission, or demand-side options are appropriate for maintaining system reliability cost-effectively. This is really more of an advisory function than a planning function in a market environment, and great care should be taken in a regulated environment to ensure that solutions are not too prescriptive.

The regulatory framework should provide for periodic filing of information by the appropriate market participants with the regulator, and for the regulator to convene proceedings in which goals are established for generating and transmission facilities, and also for cost-effective programs aimed at demand-side participation.

Demand-side Resources

The regulator must be able to require load-serving distribution entities to implement programs aimed at increasing "demand responsiveness" during times of peak demand, thus preserving system reliability and/or dampening prices at peak times or reducing overall operational costs. Demand responsiveness refers to the ability of retail customers to reduce or curtail consumption during periods of high electricity prices and is critical in generation markets. Even in a regulated regime, benefits pertaining to system cost associated with lowering peak demand can be realized in operational cost savings and reduced need for generation capacity. Demand responsiveness in a generation market paradigm can also reduce the ability of sellers to manipulate prices by exercising market power. These programs should leverage existing metering and communication infrastructure.

Generation Rate Regulation

With the introduction of IPPs into a market, a standard for the reasonableness of wholesale market rates becomes necessary, along with a regulatory function to regulate prices for electricity sold by the IPPs or by incumbent generation resources to the load-serving distribution utilities and others. If a competitive generation market is part of the reform, generators that lack market power may be permitted by the regulator to have blanket authority to sell at "market-based" rates. If, however, the regulator determines that the IPP has market power, the IPP's rates may need to be regulated on a cost-of-service basis by the regulatory authority.

If the regulator seeks to manage competition tightly or keep generation fully regulated, then the regulator must determine how prices will be set. In some countries, prices are set at marginal cost with an administratively determined capacity price. Price

can also be regulated to embedded average cost plus some percentage above that to provide incentives to sell surplus power.

Transmission Access, Rates, Terms, and Conditions

Transmission service ordinarily remains a monopoly service in restructured electric markets. However, if competition in generation is introduced, open access to transmission facilities is vital. The regulator must specify the rates, terms and conditions of transmission service in a way that is fair and nondiscriminatory with respect to all market participants. The regulator must also be consistent with the market design. Moreover, the regulator will still be responsible for setting rates under which market participants can gain access to the transmission facilities.

Cost Separation and Cost Reflectivity

Cost recovery for each portion of electricity production and delivery becomes an issue as electricity sectors are restructured. In a vertically integrated environment, regulators typically consider generation, transmission and distribution costs in a single bundled retail rate. In a vertically unbundled environment, regulators must be involved in establishing separate (unbundled) rates for each portion of the supply chain (generation, transmission, and distribution) to provide better transparency in the rate structure. Unbundling rates for each part of the supply will also aid in the use of cost-reflective rates by apportioning the fixed costs associated with supplying power on the basis of cost causality and thus allowing customers to face the marginal cost of energy consumption.

Cross-subsidies and Public Benefits Programs

Government and the regulator may wish to promote social objectives. For example, the subsidization of one customer class by another can allow poorer customers to afford electricity service. Another objective may be the extension of service to rural areas or the promotion of environmentally friendly generation resources. These subsidies or charges have generally been recovered through bundled rates. However, with cost separation, it may be possible to embed these subsidies and charges in fixed rates in a transparent and less distorting manner. Such a policy may require a revision of the tariff structure.

Obligation to Serve

Traditionally, vertically integrated utilities have had the obligation to serve customers. However, in a restructured environment where wholesale prices are market-determined, distribution companies serving end-use customers may be tempted to curtail some customers because of concerns about high prices. The obligation to serve must be reconsidered, and most likely retained. However, distribution companies serving customers should be encouraged or required to develop new tariff structures such as time-of-use pricing or interruptible tariffs with the regulator so that customers can voluntarily curtail consumption when it is advantageous to do so.

The obligation to serve also takes on a new meaning for generators participating in the wholesale market. The new framework may consider rules that force generators to

offer all of their capacity to the market to reduce the risk of withholding capacity from the market to drive up prices.

Cogeneration, Renewable, Distributed, and Intermittent Generation Resources

Cogeneration and other small power producers may offer generation alternatives for load-serving distribution companies and large industrial customers, or they may be part of a public benefits program. In a regulated market, it may be appropriate for these resources to be priced on the basis of "avoided cost," as has been done in the past, though the regulator should take care in determining avoided cost to ensure that captive customers are not "overpaying" for power. However, in a competitive generation market environment, retail electricity providers may no longer own or construct generation facilities, and avoided cost may be replaced by market prices for generation. The regulator then must decide how to continue pricing this alternative output or whether these small producers should compete to sell their output like other generators.

Market Power and Market Monitoring

Competitive generation markets, if part of the reform, may require oversight to assure that competition is fair and that market problems do not arise to increase the cost of electricity above amounts deemed fair, just, and reasonable. It will be incumbent upon the legal and regulatory framework to outline what constitutes an exercise of market power leading to unreasonable prices. Moreover, the legal paradigm must also decide what institution has market-monitoring authority: the regulator, the competition authority, or an independent market monitor. The legal and regulatory structure must develop tests and models to assure that markets are functioning effectively and that no participants are able to exercise market power. If market power is detected, the regulatory and legal institutions empowered to oversee and regulate the market must also decide how violators will be punished and whether to levy penalties.

Consumer Protection and Codes of Conduct

Competitive generation markets pose opportunities for certain abuses that may work to the disadvantage of customers or other market participants. The regulator must develop rules and codes of conduct for business transacted between affiliated companies. Additionally, retail customers may still be served by a monopoly provider. If the provider does a poor job at procuring electricity from the generation market at the least cost, consumers can be disadvantaged through no fault of their own. The role of the regulator becomes one of assuring that the distribution companies' energy portfolios are managed prudently and that those portfolios include an appropriate balance of energy resources to serve end-use customers.

In addition to customer protection in a generation market, regulated utilities must abide by reliability rules and quality standards. To help enforce such rules, the regulator may set up a system of penalties that utilities must pay directly to customers. The utilities could also be rewarded for outstanding service through increased returns.

Existing Contracts

In the transition from the vertically integrated regime of electricity service provision there may be existing contracts between the incumbent generation provider and

certain large industrial customers. These customers may be locked into contracts for many years into the future and unable to take advantage of a new market environment. The legal framework must decide on an appropriate transition mechanism that is fair to all parties when customers wish to be released from their contracts.

Another issue that arises with existing contracts pertains to those customers who wish to maintain the contract. These existing contracts must be maintained for generation as well as delivery across the transmission system. Hence, a mechanism must be decided on to ensure that those existing contracts continue to be deliverable.

Existing Contracts and Sales of Generation Facilities

As IPPs are allowed to participate in an electricity market, the regulatory and legal structure will have to establish various rules for maintaining or dissolving the contracts that may be linked to a particular generation facility. Moreover, there are questions about whether the incumbent utility should have a contractual right to all or a portion of the output of the plant after the sale, for how long and under what terms and conditions.

Metering and Telemetry

For any good market design or regulated system to function well, the appropriate metering equipment must be in place. The type of generation market design or regulated tariff structure will dictate the type of technology used, but the regulatory regime will need to consider the reliability standards for this equipment, as it is crucial for determining financial settlements in a generation market or the cost of service in a regulated environment. Moreover, the regulatory regime must decide who will pay for this metering equipment and how metering costs will be recovered in rates.

Information Requirements and Disclosure

The new legal framework must address the types of information that will be publicly available, when it is available, and the format in which it is available. This is crucial to the generation market design and the functioning of the regulator in conducting rate reviews in a regulated environment. For example, how and when are market prices posted in a market environment? What kind of transmission system information will be available? Will there be a release of generator bid and technical data in the presence of a generation market and when? How will released data be used? If data and information are considered confidential, will the regulator or the market monitor have access to this information, subject to an appropriate confidentiality agreement?

In a regulated environment, the regulator must determine what data is needed to conduct rate reviews and the frequency of the data collection. Moreover, the regulator must be prepared to justify the data request to regulated companies as well as tto politicians who may view data collection as overly burdensome.

Regulator Resources

Given the list of concepts and questions that must be answered, there may be not only a shift in emphasis regarding the responsibilities of the regulator but ever increasing and technical duties. The regulator will still concerned about cost-of-service rate setting but will now be even more concerned about the fairness and effectiveness of competition,

if that is included in the reform. It may be reasonable to establish funding for the training of regulatory staff so the regulator will continue to have the necessary skill sets in the restructured environment.

Interagency Coordination

With the advent of competition at the wholesale level, different government agencies and departments may have conflicting or overlapping jurisdiction over the electricity sector. Where possible, it will be necessary to clarify the roles of these agencies in regulating the industry. Moreover, where different agencies oversee different aspects of the industry, it will be crucial to establish procedures and protocols by which these agencies can coordinate their actions.

Governance Structures Where Competition is Introduced

The governance structure of the market and system operators is a key feature of any market restructuring for electric power. The following criteria are generally considered important in devising a governance structure with independence of the operator institutions from market participants, active participation by the market participants in the governing process, knowledge and experience in the power industry, and enough flexibility to respond appropriately to changing industry conditions.

The governance paradigm will ultimately determine the degree of independence the operator institutions (the ISO – independent system operator – and associated organizations) have from market participants and other interested stakeholders. Of course, a lack of independence, whether perceived or real, can affect the confidence of stakeholders, which in turn may affect the performance of the market and system operator institutions. While independence may be desirable, it may also be useful to include the market participants and other stakeholder groups in the governance process to ensure transparency in decisions and to build confidence in the operator institutions.

When stakeholder groups are active participants in the governance process, voting rules, veto rules, and agenda-setting protocols become even more important in ensuring some sort of independence. Under certain voting mechanisms, it may be possible for one stakeholder group to exercise influence over market and system operation, thereby gaining an advantage in the market.

If complete independence of the governance structure is the goal, then power sector knowledge and experience must be considered. Most industry knowledge and experience will rest with the stakeholders, and one way to ensure independence is to have a governing board that is independent of stakeholders. If this is the desired governance model, then those individuals appointed to the governing board should have industry knowledge and experience on which to base crucial decisions.

Flexibility of the governing board in making decisions and sometimes responding quickly to changing industry conditions can be crucial to effective market and system operations. Voting mechanisms, veto powers, and governance protocols are important to flexibility in decision making.

In summary, the proposals on governance must consider the following details regarding possible governing board configurations, the independence and ultimate authority of boards, voting mechanisms, and the jurisdictional relationship between governance boards and other institutions.

1. Degree of independence of the governing boards from stakeholder groups.

2. The structure of governing boards.
    i. One board independent of all stakeholder groups?
    ii. An executive board with final authority independent of all stakeholders with stakeholder advisory boards?
    iii. One board with decision authority made up of stakeholders? How many individuals from each stakeholder group will sit on the board?

3. Voting mechanisms
    i. Simple majority voting for approval?
    ii. "Super" majority needed for approval?
    iii. In the case of stakeholder boards, weighted voting stakeholder groups? Or one vote per individual?

4. Authority of governing boards
    i. What institutions report to the board?
    ii. Must the board report to any other institutions?

Market Concepts and Questions

If the reform path includes a movement toward competition in generation, a market model can be constructed that takes advantage of sound theoretical and practical principles from economics and power systems operation, and of the successes and failures around the world. It is imperative that the physical and engineering realities of power system operation be accounted for in any model of generation competition. In deciding on a market model that is appropriate for the country context, the following questions must be asked.

1. What type of generation (or even transmission) services should be opened for markets and competition?
    a. Energy.
    b. Ancillary Services.
        i. Automatic Generation Control.
        ii. Reserves (spinning and non-spinning).
        iii. Black Start Capability.
        iv. Reactive Power and Voltage Support.
    c. Capacity.
    d. Transmission rights (physical or financial).

2. Who will participate in the markets
    a. Generation resources.

   b. Load (with or without a size threshold).
   c. Marketers and Traders.

3. Will the energy market be a pool-based market, a bilateral-only market, or a hybrid including pool and bilateral market options?

4. How many and what type of organized "pool-type" markets, if pool markets are preferred, for energy should be conducted by the market operator?
   a. Day-ahead.
   b. Hour-ahead.
   c. Real-time (for balancing).

5. What will be the bidding rules in all markets (price, quantity, and technical data)?
   a. Generator bidding parameters.
   b. Load bidding parameters.
   c. Marketer and trader bidding parameters.
   d. Timing of bidding.

6. How will prices be determined?
   a. Uniform price mechanism for each market.
   b. Multi-part price mechanism to reflect "lumpy decisions".
   c. Pricing intervals (by hour, by dispatch interval).
   d. Negotiated prices between parties like a bilateral market.

7. How much separation will there be of market participants from market and system operations?

8. Will there be separation of the market operator from the system operator?
   a. If there is separation, a delineation of coordination procedures for scheduling and reliability is needed.
   b. If placed together, how to ensure the system operator does not take a position in the market.
   c. Procedures and protocols for committing or scheduling units.
   d. Procedures and protocols for dispatching units in real time.

9. If there are markets for both energy and ancillary services will markets be cleared separately or jointly? What kind of substitutability is allowed?

10. What are the procedures for scheduling bilateral contracts?
    a. Reliability purposes.
    b. As a part of the economic commitment and dispatch.
    c. Physical deliveries.
    d. Financial deliveries.

11. What are the procedures for scheduling trades across international borders?
    a. As a bilateral transaction.

b. As a bid into the pool-type market.

12. What are the procedures for the dispatch of intermittent and renewable resources?
    a. Includes distributed resources.
    b. Includes co-generation where available capacity varies according to steam or heat requirements.
    c. Dispatch as must-take resources?
    d. Dispatch as a bilateral schedule?
    e. Will these resources be allowed to set the market price?
    f. Financial settlements when resource generation levels fluctuate.

13. What are the financial settlement procedures?
    a. Relationship between different markets.
    b. Time period for settling accounts.
    c. Creditworthiness requirement.

14. What are the procedures for scheduling and dispatch of must-run units?
    a. At what point in time will units be considered must-run?
    b. Will must-run units be able to set the market price?
    c. How will must-run units be compensated?

15. What is the paradigm for access to the transmission system?
    a. Negotiated open access?
    b. First-come, first-serve open access under non-discriminatory terms and conditions?
    c. Open access with “usage” charges similar to PJM in the United States?

16. What is the paradigm for pricing congestion and losses?
    a. Nodal congestion pricing and marginal losses?
    b. Zonal congestion pricing and losses?
    c. Flowgate congestion pricing with marginal losses?

17. What are the information requirements and disclosure regarding transmission?
    a. Information availability about the transmission system.
        i. Historical.
        ii. Current.
    b. Platform for providing transmission system information.

18. What are the information requirements and disclosure regarding generator behavior?
    a. Will generator bid and technical data be released?
    b. If bid and technical data are released, what are the terms of the release?
    c. Procedures for determining the confidentiality of generators?
    d. Use of released data for market monitoring purposes.

Implementation Outline for Generation Markets

Given the market design on the basis of answers to the questions in the previous section and the legal and regulatory framework, it is then necessary to implement restructuring and wholesale markets by taking the following operational steps.

- Establish new institutions and their respective responsibilities
  - Market operator
  - System operator
  - Market monitor
- Staff new institutions
  - Training
- Establish governance structures and boards.
- Establish training protocols for new institutions
- Codify the changes needed to existing institutions.
- Implement changes in tariff structures where necessary.
- Install essential equipment.
  - Metering
  - Software for market and system operation
- Identify provisions for handling existing contracts.
  - Sunset provisions.
  - Preservation of contracts where needed.
- Determine needed ownership changes
  - Separation of generation, transmission, and distribution.
  - Divestiture of generation assets.
- Establish market trials
  - Testing software.
  - Ensuring that market participants understand the rules.
- Create schedules for market and system operation
  - Timing of implementing market features.
- Create schedules for transition to new tariff structures
  - Timing of energy price "liberalization"
  - Necessity of gradual changes to new tariffs
- Address other issues as needed

All requisite institutions, protocols, legal changes, and infrastructure, as discussed above, should be accounted for in a transition and implementation plan. In addition, the timing of implementation should be outlined in advance so all stakeholders are aware of the schedule. This will facilitate coordination and the identification of potential problems. Finally, as with any reform, great care and time should be taken to identify all the questions and to obtain thoughtful and satisfactory answers to those questions. Reform, especially if it includes any movement toward competition in generation, must be done methodically and carefully to avoid many of the mistakes made in other countries.

As has been observed, hasty answers to the questions posed in this paper along with rushed implementation can lead to grave consequences. All one needs to remember

is the disaster that befell the California reform in the United States to see what can happen. An example of successful reform undertaken and in a methodical, meticulous, and step-by-step fashion is the PJM market in the United States. The current structure of the market and reform in this region did not happen overnight but has evolved slowly since 1996.

Concluding Remarks

This paper has outlined many of the key concepts that regulators must know when moving forward with power sector reform. There are questions and considerations of the legal and regulatory framework as well as questions that must be addressed when considering generation competition as a part of market reform. To attempt to answer all of these questions in one paper is folly. However, the questions and considerations posed here will hopefully make regulators and policy makers involved in power sector reform think about all of the complexities and minor details that must be addressed when moving forward with reform and understand that this is not a simple exercise. Thoughtful deliberation is called for before proceeding into more complex reforms.