Planning, Markets and Investment in the Electric Supply Industry

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Abstract

Effective planning of the complex electricity supply network is essential because of the long lead times required for the development and placing in service of large new generators and transmission lines. Yet much can change while this physical process is being undertaken in terms of costs, prices, technological innovation and public policies, particularly about the environment and fuel diversity. The essential nature of well-constructed markets in yielding accurate, up-dated information about the likely effects of these many factors, as well as the use of advanced planning tools like “real-options” analysis are described, together with how these tools should be carefully staged and integrated with the planning process.

1. Introduction

The Federal Energy Regulatory Commission through its Order 890 mandated the ISO/RTOs responsible for operating the electricity grid and for conducting wholesale markets in various regions of the country to conduct periodic system planning exercises to identify needed transmission and generation facilities, both for reliability and economic reasons. Yet, to many Americans drilled in the rhetoric of the “free market”, planning seems like a contradictory term for an industry just recently deregulated, and the term recalls all of the ills and heavy-handed oppression of socialist, centrally-planned economies. The rationale for collective planning in this industry, how it can complement the functioning of properly structured markets and how those markets can inform updated plans when timed and sequenced properly are analyzed.

Planning has been an essential, integral part of the electricity supply industry since its inception because 1) the industry is capital intensive, 2) the long lead times required to construct and complete new facilities and 3) the absolute necessity of having adequate transmission and generation capacity installed to maintain reliability both because the public demands it and electricity cannot be stored. Heightened by the Northeast Blackout of 1965, the National Electricity Reliability Council (NERC) was formed to establish voluntary reliability standards, and to perform studies to determine whether individual utilities and power pools were in compliance with those standards. What has changed over time is the scope and identity of who does the planning for power supplies and who identifies the requisite investments as societal concerns have evolved. In the emerging quasi-market-supply structure that exists for the industry in many sections of the country today, the very nature of and responsibility for that planning is still a work in progress. Nevertheless, FERC has transformed NERC into an Electricity Reliability Organization (ERO) with the power to penalize entities for failure to maintain reliability standards. And an economic planning process to relieve congestion, where economical, has been established in all regions of the country.

However, because the flow of electricity obeys the laws of physics and not the precepts of humans through their laws, markets and institutions, emerging problems include: coordinating plans horizontally among neighboring ISO/RTOs and vertically down to the distribution and retail level and back up the supply chain to the primary energy sources. Integrating public policies about the environment, energy efficiency standards and subsidized use of renewable sources of generation compound the planning problems and coordination challenges for all entities comprising this industry.
2. Evolution of Planning

Of course the traditional vertically-integrated, either private-regulated or government-run, electric utility has been a centrally-planned industry with exclusive supply rights and obligations to serve in particular areas of the country. Since this was the predominant institutional form for providing electricity service in the U.S. through most of the twentieth century, it is not surprising that each supply entity has engaged in careful strategic long-range planning, given its desire to maintain and enhance service reliability and thereby customer satisfaction. Over the past one-hundred years, however, the scope of those plans has gradually expanded: 1) geographically, as the size of individual firms increased and voluntary power-pooling organizations were formed among firms, 2) over social concerns, as environmental, then public health and safety and finally regional economic well-being were recognized as important consequences of electricity supply facilities, and finally, 3) over the type and primary source of energy supply, following the oil supply shortages of the 1970’s when “integrated resource planning” became the popular process for public involvement in a democratic society. Thus a long and ever-more comprehensive planning process has evolved both within and external to this industry. One reason that the supplying institutions have tolerated the increasing external intervention in their own internal planning processes is simply that without that public approbation, the legal right to site new generation, and in most jurisdictions, transmission facilities, could be denied.

In fact in many regions of the country, the process of acquiring the necessary regulatory approvals to site and construct new facilities becomes the major impediment to doing so, primarily because of the time and cost of gaining the necessary approvals to proceed. In many instances, those approval costs exceed the actual costs of physical acquisition of land and resources and of construction. “Deciding how to decide” has become an institutional art-form, involving legal, political, economic and behavioral insights on how to design efficient and fair decision processes (and also for parties intent on using those processes to block particular projects).

The added complication for those portions of the electric supply industry that have been deregulated and subjected to market-driven revenue streams arises when they must determine whether or not to invest, based on market-related criteria, but also on having to bear the risk of public-policy-type decisions on siting. A regulated or public firm could be reasonably assured of recovering those decision-related costs sometime in the future; the prospects are far less certain for a firm in a competitive market. While firms in other competitive capital-intensive industries also face siting approvals before they can expand their capacity, they can minimize their risk simply by waiting to construct until supply shortages have driven prices in the marketplace high enough to warrant the risk. Because of real-time delivery and society’s utter dependence on reliable electricity supplies, modern societies simply may not be willing to rely on market forces alone to determine whether suppliers are willing to invest in a siting decision; some degree of public participation and subsidy in recognition of the public nature of the decision may be warranted.

However, in the transition to market-based wholesale electricity supply in many regions of the country, the allocation of responsibility for and the sharing of the risk of this decision-making in the planning process has yet to be worked out. As an example, in New York State a one-stop siting law had been in place; wherein all public permits were reviewed and provided through a single integrated process. Since the advent of competitive wholesale markets, that law has been allowed to lapse, compounding the risk for private investment as piecemeal approvals must be sought. Rationalizing the private and public nature of these approval processes is particularly important for electric transmission lines where authorizations must be acquired from many political jurisdictions that might be spanned by the desired new facility. If those approvals are not granted simultaneously, there is a tremendous incentive for jurisdictions to delay their individual decisions so that they are last in line, and therefore able to extract the most favorable concessions. These are all factors that the private merchant builder must factor into her decision on whether or not to try to invest and to begin to seek the necessary approvals; they are also factors the public sector must consider if it desires a market-driven process that serves the public interest.

Problems to be resolved abound. With a regulated vertically integrated industry, the supply entity that was trying to minimize the total cost of supply (an assumption), subject to meeting all demand at a specified level of reliability, would decide whether it was more efficient to build new transmission or new generation, where, when and of what type (fuel source). In this context, the entity might even consider the value in terms of economic risk reduction of maintaining a stable of diverse generation sources, in terms of their primary fuel source. In a market context, a generator must decide whether and where to build
based upon the going market price in different locations. A competitive transmission company must base investment decisions upon price differences in electricity between regions, plus any fixed delivery contracts it can assemble ahead of time from buyers and sellers. Note that decisions to invest by either type of firm are likely to reduce the original price levels or price gaps, so they must take that market effect of their investment into account. They must also consider how the interaction between likely new generation and transmission investments will affect their revenues in the future. But, without further public intervention setting a payment (or subsidy) for providing added security, these firms would not rationally consider the effects of their investment choices upon system reliability or fuel diversity risk. That’s one reason why many jurisdictions are establishing subsidization mechanisms for bringing renewable-resource-based generation on line; although in some instances the transmission requirements to bring that remote energy to the load locations are neglected.

These anomalies all suggest at least an equal need for planning under a wholesale market supply scenario, but of somewhat different type and scope than was present under regulated vertically integrated institutions. The FERC has recognized this need in mandating that one of the requirements for ISOs/RTOs is for each to establish a planning process to identify needs and to initiate, first, market-driven, and then if inadequate, regulatory-based investments that might be required. And in response of the 2003 Blackout, the Federal Energy Act of 2005 empowered FERC to establish an Energy Reliability Organization (ERO) to make NERC’s reliability standards mandatory and enforceable with penalties for non-compliance.

In many ISO/RTO jurisdictions, however, a legal semantic distinction is made between facilities needed for reliability purposes and those that might further some economic benefit (e.g. lower wholesale electricity prices). Since both functions are served over the same transmission network, this distinction is nonsensical in terms of both the laws of physics and economic principles. Almost any transmission line that is built to enhance reliability will most probably also reduce congestion at some times of the year; thereby, reducing wholesale costs. Similarly, any line constructed to facilitate economical transfers of power most likely will affect reliability somewhere on the system. It may also facilitate access to diverse sources of generation further away, thus enhancing reliability and security.

If we add to this menu additional public concerns about the environment, sustainability and robust resilience to possible terrorist attacks, the required public overview of the planning process is further complicated. And additional factors that will need to be considered are whether a competitive wholesale marketplace for electricity is a decentralizing or centralizing force for the ultimate evolving configuration of the system. As a result, determining whether the system will be inherently more or less resilient to insults, whether natural or human in origin, and responsive to retail consumer demands are simply additional factors to be accounted for in the planning process. The first requirement is that such an integrated process exist to guide and offer benchmarks for the future evolution of the industry and to lead those involved to review these issues systematically.

3. Proper Market Design and Planning

A PSERC report [1] describes the principles that should govern the design of every market and the rules and regulations that should govern its operation and evolution. An efficient market simply cannot exist and function without a plan. That is particularly true, as is the case of electricity supply, where the production facilities (generation) are large, discrete and take several years to plan and build, and the means of conveying the product to market is singular and over a network that too is subject to discrete, lagged scale effects. At the very least, decisions to modify and expand the network’s topology need to be performed in a predictable, systematic way if markets for generation supplies are to be non-erratic. Conversely, efficient locationally-differentiated markets for generation provide an important stimulus for investment decisions on new transmission. So the dimensions and timing of these markets need to be interspersed carefully with the planning process; if done well, each can guide the other.

A well-functioning, vertically-integrated, properly regulated system would seem to be ideal for performing these tasks, provided accurate information on costs are available. However, under regulation there are powerful incentives to disguise costs. In contrast, market allocations offer tremendous incentives to find lower-cost ways to serve the buyers and to foster innovation. So, the trade-off may be a perfectly optimized system over the wrong data in the case of a regulated regime, versus a less than perfect system under market allocations, but one that is motivated by better information and incentives to innovate. Thus, in order to plan under a market regime, the inherent
uncertainty about future events and states of technology must be acknowledged.

4. Conceptual Framework

Electricity system planning (a method for accomplishing something) is performed over two dimensions: space and time. The desirability of having different markets over space where physical constraints impede the costless transfer of power are well-established and these spatial differences have been used to affect behavior where wholesale markets exist through locational market pricing (LMP). What is less precise are the principles used to sequence markets over time at each of these locations, and to alter the grouping of locations where markets are held as the congestion on the system changes.

4.1 Structure of Individual Markets

To the questions of where and how frequently are those markets to be held should be added the question of what should the structure of each market be, precisely because electricity supply is a multi-attribute commodity? It is primarily to ensure the reliability of supply that a planning process exists, although the price of the commodity ($/MWh is the second attribute) is the concern that leads to economic planning. But these two attributes are provided together, in various combinations and as constrained by the physical devices employed. This is true from the far-future planning process for investment in new facilities under discussion here, but it also arises in the week- and day-ahead unit commitment process, the hour-ahead management of operating reserves and the even shorter-term operating concerns with ramping and regulation. In each of these cases, the operative question is: how long will it take to get the needed physical generating capacity ready to produce - - whether it is to be constructed, to be turned on, to be warmed up or to change its operating point? What is the lead-time required to get units to the point they are able to provide energy (or VARs) following a decision that incurs appreciable costs. Furthermore, the choices available in real time hinge on the choices made in previous periods, so the structure of those market should be compatible.

That is why any forward capacity market should be specified in terms of two prices - - a capital cost per MW and also a maximum energy price per MWh. As illustrated by Sally Hunt [2], that is the way an optimal generation expansion plan should be conducted under a centrally-planned system (where presumably all of the costs are known with certainty). And as shown in Figure 1, it is the least-cost combination of low-capital-cost, high-operating-cost peaking units and high-capital-cost, low-operating-cost base-load units (with a variety of other units in-between) that are required to serve the system’s load-duration curve that should govern the selection of the next generating unit to be built. With active demand-response, the planning becomes more difficult because it alters the shape of the load duration curve. This would be particularly true if all customers paid a two-part tariff with a separate charge for their peak MW demand, if it coincided with system peak, as well as a bid per MWh. But that is a subject for a separate research project. Currently, most planners treat demand response as a form of supply and this creates the major problem of trying to determine what the demand (bids) might have been without the demand response so that the demand response can be subtracted. In fact, in a PSERC-conducted forum of industry executives [3], valuing a “nega-watt” properly was identified as one of the greatest challenges to effective planning.

Figure 1: Example of two-part offers for capacity and energy

As Hunt also points out [2], the theory for developing efficient, marginal-cost-based rates under a regulated pricing regime relies on the same construct from Figure 1 of an optimally-configured system. Users in off-peak periods where base-load, or intermediate units are on the margin, should be charged only the marginal running costs of the last, highest-running-cost unit selected to meet demand during that period. However in the peak periods where peaking units serve that marginal need with the lowest combined capital and operating costs, all units operating at that time should be paid both the running cost of the peaker, plus its capital costs. Otherwise, the peaking unit will not recover its capital costs. In a regulated market, this is a violation of the U.S. Constitution as Hunt also points out [2]. In a market regime, no entrepreneur would build unless they thought they could recover those costs. So even in
short run markets, some capital costs need to be allocated to peak-period users.

Just as important, note that the intermediate and base load units also need to receive the capital cost of the peaker if they are to recover their own, far-larger capital costs in these markets. They make up the rest of their capital costs by the infra-marginal spread between the higher running costs of the peaker in peak-periods (in the case of the intermediate units), and that plus the spread between the running cost of the intermediate units and those of the base-load units in the intermediate load periods in the case of the base-load units. In a market-based wholesale exchange, the same principles apply, we simply substitute the two-part offers by the suppliers (and preferably the two-part bids by customers to generate the load duration curve). The important principle is that these markets should be based upon two-part prices: an availability price for capacity and a price for the energy delivered.

4.2 Market Sequence over Time

The primary rationale for having a sequence of markets over time is that things change: buyer preferences, supplier costs, weather, technology, and underlying public policy and infrastructure investments. Societies could round up the experts and try to form a consensus about how all of these factors might change in the future, but establishing a forward market forces participants to commit money in support of their current expectations. As such, the outcomes of forward markets are likely to provide truthful revelations about the participants’ perspectives on the future. Even greater assurance can be provided if financial arbitrage is permitted between future and real time markets in order to check strategic behavior by physical suppliers because many of these electricity markets are oligopolistic.

In PSERC project 10-01 [1], the effect of the timing of a forward market in relation to the lead time when commitments for capacity additions had to be made was explored, as well as the influence of introducing arbitrage. Holding a forward market prior to the lead time required to commit to additional physical capacity was shown to be crucial in increasing the amount of investment and in lowering subsequent real-time prices [1]. But since there were only three physical suppliers in these experiments, three other participants were introduced to play a voluntary arbitrage role. These exercises were conducted without an electricity network that might restrict flows between buyers and sellers, so it would be of interest to extend these exercises to allow a “planner” to alter the configuration of the grid at discrete intervals. Presumably, these changes in topology should be timed (or at least noticed) prior to decisions to invest in new generation at specific locations (and a forward market might be conducted both before and after such a planning decision about new transmission, but prior to the latest date when commitments to build new generation need to be made).

Similar arguments are relevant about the timing of forward markets prior to large-scale buyer investments in demand-mitigation systems, but since the lead time in completing those demand-side investments is usually shorter than the time required to plan, permit and construct new large-scale generation, locating a forward market before the time required to develop new generation may also support new demand-side investments. In fact, one argument for holding a number of forward markets with a sequence of time horizons regularly (e.g. annually) is that it would allow both buyers and sellers to respond to each others’ investments and to readjust their positions, both physically and in terms of financial hedges. In addition, holding a sequence of forward markets would enhance the liquidity in the different forward markets since participants would have some ability to adjust their commitments as new information becomes available.

4.3 Liquidity and Market Power

As discussed above, most electricity markets are oligopolistic, and so allowing purely financial entities to participate should be encouraged both to provide the insights of additional observers and to increase the number of competitors in each market. However, because of the increase in risk as markets are conducted farther forward there are likely to be fewer participants in each segment. One side of every forward market should clear in the real-time, and for most electricity systems that employ spatially different prices (LMP), multiple real-time markets mean spreading suppliers over separate zones with different prices. In certain cases, this raises concerns about the exercise of market power in real time. If the same spatial granularity is maintained in forward markets where there may be even fewer participants, the problems of market power might be even larger (This could work in the opposite direction if real time prices were exceptionally high due to the short-run exercise of market power and if the ability for new generation to enter was relatively easy).

This is one reason why Kamat and Oren [4] have suggested that the number of pricing zones should be
reduced in the forward market with the prior knowledge that forward exchanges would be cleared using some preset weighted average of real-time prices over the zones that are combined. Not only would this approach combine the bids and offers of a larger number of participants in the forward market, it would still maintain an anticipated inter-temporal price difference for electricity (and hedges based upon the change in those differences) that is the essential information that is sought by organizing these forward markets. What is essential, however, is to have both physical and financial participation.

5. Perspectives of Practitioners.

An industrial forum was convened by PSERC (project 09-01 [3]) to draw on a wide range of perspectives from suppliers, buyers and ISO/RTOs from across the country to discuss planning needs and desires. The participants identified different planning needs and desired structures that vary widely, depending upon the geographic and institutional perspective. This is not surprising since the industry’s configuration - - electrical, institutional, economic and political - - varies by region, and each particular structure has somewhat different planning needs. However, everyone did agree that planning in this industry is essential. As an example, in regions where markets with LMP are widespread and the customer density is high, an incremental approach to planning was preferred by most participants; whereas, in more sparsely settled areas the need for transformative planning (e.g. a 765kV overlay of transmission) was seen as important.

Three institutional advances were identified that had the potential to improve the planning processes for all forum participants:

1. A mechanism and framework for multi-state regional planning, and/or the coordination of separate plans across individual ISO/RTOs.
2. A need for some overarching entity to integrate broad social objectives like the environment and/or fuel diversity within the more traditional electricity reliability and economic considerations across institutions and control areas.
3. Mechanisms to value a “negawatt” for planning purposes that encompass differing certainties of demand response as compared to “iron-in-the-ground” supply responses.

Of these three factors, the first is coming to fruition in practice through the creation of regional planning initiatives, like the Eastern Interconnection Planning Collaborative (EIPC). And the third is most easily addressed through the installation of real time metering and by implementing real time pricing and making it available to all retail customers, as outlined in another PSERC project [5]. Again, the real benefit is obtaining truthful valuations of foregone usage by customers if they refuse to pay the true cost of delivery in certain periods, as compared to many existing demand-response programs where the benchmark level of usage is subject to gaming over a span of years. And as emphasized earlier in this paper, an additional facet of pricing that would reveal the customer’s valuation of both energy and for their peak capacity requirements would be to implement two-part, real-time pricing schemes that included both energy and capacity charges.

6. Integration of Markets with Investment Decisions

As emphasized in the conceptual section of this paper, it may be important to integrate forward markets with day-ahead and spot markets in order to encourage adequate investment of new generation. In practice, no entity has deployed the two-part pricing scheme outlined earlier, but most ISO/RTOs do use a separate capacity market in combination with their energy markets. As an example, the NYISO requires its load serving entities (LSEs) to secure adequate capacity one month ahead of real time to meet their projected peak demand in both the current summer or winter six-month period, plus the pre-specified margin to meet adequacy requirements to maintain system reliability. Furthermore, there is a loose coupling between capacity and energy suppliers through the requirement that capacity providers must offer into a day-ahead energy and/or reserve market in order to be paid their capacity prices, but there is no linkage between energy and capacity price offers and the selection of capacity suppliers.

In the case of the NYISO, these capacity markets are held long after both generators and demand side management suppliers need to make their investment decisions, and so commitments to build additional capacity must be based upon long-term, multi-year projections of those month-ahead market prices. Both ISO-NE and PJM have implemented forward capacity markets that are scheduled three to four years prior to the actual use date, but the bids and offers bear no linkage to subsequent energy offers (one-part offers), and participation is mandatory for potential participants should they wish to receive capacity payments. Those suppliers who are selected in these
forward markets commit to firm physical transactions so there is no financial arbitrage, thereby restricting the information provided through these market transactions.

In the case of ISO-NE’s Forward Capacity Market (FCM), there are a number of rules in place that place caps on the offers submitted by the owners of existing generating capacity. The objective is to ensure that capacity prices above this cap are only set by offers to build new capacity and not by the offers from existing capacity. A paper by Mount and Maneeuitjit [6] describes a set of experiments of the proposed structure prior to its implementation. The results show how strategic behavior by the incumbent utilities, consistent with the rules of the FCM, has the potential to increase the capacity price, and at the same time, limit construction by new entrants by submitting offers to build new Peaking capacity that are slightly below the true cost. The losses on constructing new capacity may be small relative to the extra profits from the higher prices paid for existing capacity. In addition, the students representing the incumbent utilities were able to “create” capacity shortages legally so some new capacity had to be built more frequently than was strictly necessary (e.g. by exporting capacity and by withholding capacity to repower some existing units), and the capacity price can be high when new capacity is purchased in the auction.

In practice, both ISO-NE and PJM have found that their forward markets, both of which are really physical procurement markets since they do not allow for financial arbitrage, have led to very low prices that are not sufficient to attract new investment in generation capacity. In part that is due to very low demand growth in recent years so ample generation capacity is already in place, but the low capacity clearing prices also result from the substantial participation in these markets of demand response providers, whose capital costs are much lower than for new generation and by subsidized forms of renewable generation. So it may be too soon to gauge the economic desirability of these outcomes for the long run; although the market structures do have theoretical limitations. And despite the absence of forward capacity markets in New York, a commercial combined cycle gas turbine near Albany has been completed based upon the short-run capacity market and wholesale energy prices.

An important consideration raised by market participants in New York for designing forward markets is to consider the lead time required by the ISO/RTO to determine that the commercial projects forthcoming in the voluntary forward capacity market are insufficient to meet adequacy standards so that the ISO/RTO must call for a “regulatory solution”. At that point, invoking a mandatory physical procurement market may be warranted as a last resort before reverting to regulated rate-of-return type of pricing. But further forward than that “last-resort” lead time, the analysis here suggests that voluntary, financial forward markets are preferred.

7. Conclusions and Further Analysis

Markets always work best where the rules are laid out ahead of time and any changes in those rules and in the business or physical environment are predictable. If there were no congestion now or in the foreseeable future on the electric grid in the United States, establishing efficient markets for electricity would be easy, and potential investors in new generation would simply search for least-cost locations where they thought they could gain siting approval. Of course constructing and maintaining such a nationwide transmission system would be exorbitant, and that is why spatial pricing zones have been established so that those market-based LMPs can guide the location of future economical investment in generation and also help to identify potential transmission upgrades that might improve reliability and/or reduce overall system cost.

It is precisely because those transmission investments are likely to upset spatial price patterns affecting both existing and planned new generation (and also merchant transmission initiatives) that it is essential that that system planning be thorough, comprehensive, occur at predictable times and whose deliberations and outcomes need to be completely transparent to all parties. It is reassuring that regional planning initiatives like the Eastern Interconnection Planning Collaborative (EIPPC) are already underway.

Also needed to facilitate this planning that incorporates, simultaneously, economic and reliability considerations is an analytic mechanism that identifies “optimal” choices, recognizing the full uncertainty about future states of the world (prices, regulations and technology). While heuristic probabilities might be assigned to different future values of these parameters, it is also important to recognize that some investment choices may preclude others in the future (be irreversible), and so the actual world of electric system development may be path dependent. Thus in order to account for this possibility, a “real-options” decision tree should be used in making this probabilistic planning analysis. Note how the interjection of well-
designed markets at key points in this sequence should lead to the continual updating of key information.

To date, however, electricity markets are still “incomplete”, primarily in terms of having regularly conducted forward markets that are financial (voluntary and open to everyone). The implementation of such markets, if integrated properly with the system planning process and the decision times necessary to make physical choices and investments regarding the reliable operation of the system (e.g. investment lead-times, minimum start-up times, ramp rates), should be complementary. The shortcomings of existing forward markets and of specific details of their design are laid out here, as are suggested improvements. But further analyses that need to be performed include: 1) experimental tests of different sequencing of announced transmission investment upgrades with forward and spot markets, 2) determining whether aggregation of pricing zones in forward markets can enhance their liquidity and reduce the exercise of market power, and in the long-run, 3) a routinization of the siting process.

But perhaps the greatest advance in these markets that would lead to improved planning would result from making advanced meters and real-time pricing available for all retail customers and the implementation of two part pricing schemes, at least for physical buyers and sellers. These steps would make it feasible for customers, or aggregates of customers, to participate fully in markets for energy and ancillary services. The potential benefits of full participation by demand include flattening daily load patterns, mitigating the variability of generation from renewable sources and reducing the installed generating capacity needed to maintain system adequacy. Overall, this type of electric delivery system is likely to be more reliable, include higher penetrations of renewable sources of generation, and provide more truthful information to the planner.

References


