Improved Investment and Market Performance Resulting from Proper Integrated System Planning

Final Project Report

Power Systems Engineering Research Center

Empowering Minds to Engineer
the Future Electric Energy System

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Power Systems Engineering Research Center

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Executive Summary

Planning has always been an important component of the electric supply industry because of the size, lumpiness and long lead-times from inception to completion of its infrastructure investments, because the commodity cannot be stored and because it is delivered over a network. Because electricity is also so widely used and modern societies have become so utterly dependent, without second thought, on its uninterrupted supply, managing the required stream of investments to replace deteriorating or antiquated equipment and to meet evolving demand in different places is a severe planning challenge. That is only compounded by the whims of nature, the occasional malefaction of some individuals, evolving social concerns about the environment and sustainability, and the widespread introduction of market allocations.

A plan is described as “a method for accomplishing something” in Webster’s dictionary, and in that context efficient markets should be a big help since they decentralize a great deal of optimization and decision-making that can be useful and believable input to subsequent planning. But markets always work best where the rules are laid out ahead of time, and where any changes in those rules and in the business or physical environment surrounding them 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 technologies and locations where they thought they could gain siting approval. Of course constructing and maintaining a nationwide transmission system of this scope and magnitude would be costly, and that is why spatial pricing zones have been established so that those market-based local marginal prices can guide the location of future economic 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 system planning be thorough, comprehensive and occur at predictable times. Those planning deliberations and outcomes also need to be completely transparent to all parties. This is why markets and planning are so intertwined, and the object of this investigation is to help them complement each other thereby facilitating investment.

In terms of timing, it is well understood that electric system planning needs to project far enough in the future to reach well beyond the required start date for planning and developing individual generation and transmission projects. Many demand-side investments also look far into the future because of lags in their implementation. But those projections are made based upon forecasts of demand and prices. Why not let market activity inform those forecasts by bringing many more players into the action through forward markets that are financial?

Project Accomplishments

This report accomplishes several objectives.

- It lays out a desired sequence of having some forward markets placed earlier than the earliest commitment lead-time required for physical investment, of having regular subsequent markets to provide liquidity and to respond to updated expectations (and planning), and of laying out and making transparent the planning process and making explicit the criteria for expanding transmission capacity, where and when.

- It also reviews some of the existing forward procurement markets, showing how particular details of auction structure may lead to anomalous results. A case is made to allow purely financial participation in forward markets, both to increase liquidity and reduce the potential for exercises of market power, up until the latest time when only physical participation will provide adequate assurance that ample steel will be in the ground to keep the lights on. And especially in highly congested regions where significant investment in new generation and/or transmission is likely to alter those patterns of congestion and locational price differences, any subsequent attempt to alter pricing zones must have the process and criteria for change laid out well ahead of time.

- Finally, it is recognized that potential changes in public policy and regulation may be the most unpredictable factor, upsetting both markets and planning. That is why it is important to have a scheduled process in place to consider those potential changes (e.g. whether about the environment, conservation incentives, the use of renewables or about siting criteria and decision-making) as well so they can be factored routinely into planning and market decisions.

Conclusions and Next Steps in Research

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. It is precisely because 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 electric system planning be thorough, comprehensive, occur at predictable times and lead to deliberations and outcomes that are completely transparent to all parties.

Thus far, in economic jargon, electricity markets are still “incomplete”, primarily in terms of not having regularly conducted forward markets that are financial (voluntary and open to anyone). 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 prior analyses that should be performed include: 1) experimental tests of different sequencing of announced transmission investment upgrades with forward and spot markets, 2) determine 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. Longer shots include 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.

Table of Contents

List of Figures

List of Tables

Section 1. Introduction

The Federal Energy Regulatory Commission through its Order 890 has mandated the ISO/RTOs responsible for operating the grid and conducting wholesale markets for electricity 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. This summary report explores the reasons why collective planning in this industry is essential, how it can complement the functioning of properly structured markets and how those markets can inform updated plans when timed and sequenced properly.

Planning has been an essential, integral part of the electricity supply industry since its inception because of 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. 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.

1.1. 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 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 source, 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.

1.2. Regulation and Planning of Markets

A previous 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.

Section 2. Conceptual Framework

Electricity system planning (a method for accomplishing something) occurs over two dimensions: space and time. And, the desirability of having different markets over space where physical constraints impede the costless transfer of power at some distance are well-established (locational market prices (LMP)). What is less precise are the principles used to sequence markets over time at each of these locations, and to alter those locations where markets are held as the congestion on the system changes.

2.1. 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 the executive forum leading up to this report [3], valuing a "nega-watt" was laid out as one of the greatest challenges to effective planning.

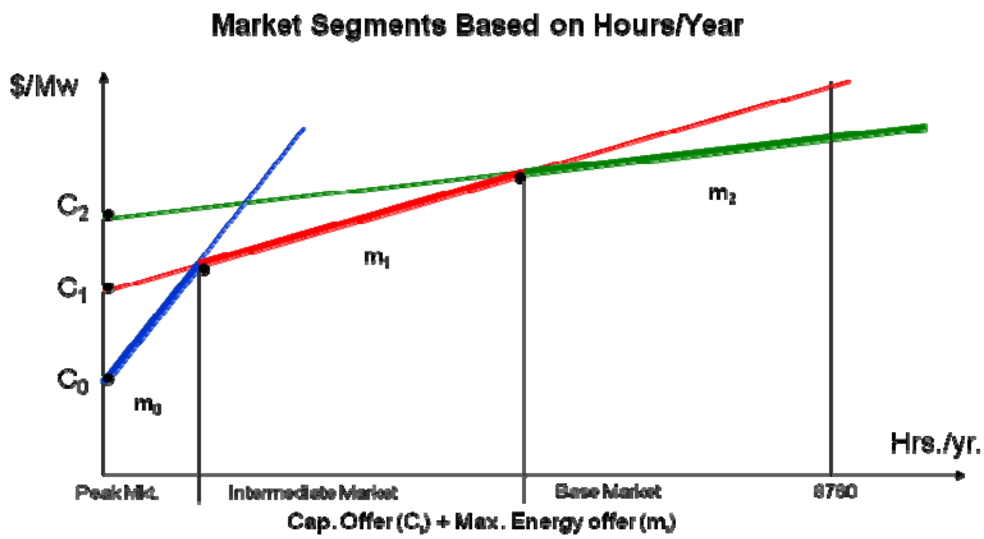

Figure 1, Example of Two-Part Offers for Capacity and Energy

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. 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.

2.2. 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 the earlier 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 emerged.

2.3. 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 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 intertemporal 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 (mandatory vs. voluntary) participation.

Section 3. Summary of Investigations

Support was provided for this project to analyze and discuss the intertwined behavior between forward markets, investment decisions and the timing of updated system planning. The work contributed by each of the principal investigators is summarized in this section and the detailed contributions are included as four appendices.

The project began with a review of the existing planning procedures employed by typical ISO/RTOs in the United States (Appendix A). Over the course of the project the planning landscape evolved dramatically, especially because of the issuance of FERC Order 890 mandating planning for both reliability and for economic purposes. Furthermore the formation of FERC's Electricity Reliability Organization (ERO), as authorized under the energy policy act of 2005, and the designation of NERC as that entity with wide-ranging enforcement powers, including the right to set penalties for non-compliance, has and continues to alter the institutional landscape. A major recent example is the formation of the Eastern Interconnection Planning Consortium of ISOs/RTOs, utilities and regulatory agencies across the east to develop a coordinated planning process that has the potential to integrate components in a hierarchical fashion from individual utilities and suppliers through their ISOs/RTOs and on to assessing the interregional impacts of new investments on reliability and the cost of power supply. This information will then be passed down to individual entities to develop an iterative process (both bottom-up and top-down) coordinating both local and regional investments. This information will also be readily available to the markets through the ISO/RTO planning processes, and it should make the potential reliability and economic consequences of particular investments more transparent.

3.1. Survey of Industry Needs

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 executive summary of that Forum is attached as Appendix B, and it identifies different planning needs and desired structures that vary geographically and institutionally. 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.

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, 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 earlier 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 report, 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.

3.2. Integration of Markets with Investment Decisions

As emphasized in the conceptual section of this report, 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. And in most cases, like the NYISO capacity market in which load serving entities (LSEs) must secure adequate capacity one month ahead of real time to meet their projected peak demand in 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 suppliers and the requirement that they must offer into a day-ahead energy and/or reserve market, 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. Selected suppliers also 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 Maneevitjit [6] describes a set of experiments of the proposed structure prior to its implementation. The results are summarized in detail in Appendix C, and they show how strategic behavior by the incumbent utilities, but still 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 were 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 is being 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.

3.3. Proposed Tests of the Effect of Planning on Markets and Investment in a Dynamic Electric System

A framework for conducting additional experimental trials to test investment decisions in a dynamic market setting were developed to demonstrate their feasibility for future research. The detailed instructions for participants in experiments of this type are included in Appendix D.

A central theme of this report is to emphasize the desirability of converting forward electricity markets into two-part pricing auctions for energy and capacity that are cleared by the lowest combined cost through an optimal power flow (OPF) equilibration. Since no area in the country currently operates under this type of regime, the proposed new experiments were based on simple energy and capacity auctions that incorporated both forward and spot markets with investment opportunities in generation. Two pricing zones were proposed for these markets, based upon congestion, and the forward markets are financial. Any physical buyer or sellers in the spot market could participate in them, as well as independent arbitragers, and they would free to take either side of the market (physical buyers could sell forward and vice versa for physical sellers). In these exercises, since there were only two pricing zones, physical buyers and sellers could also engage in spatial hedges, should there be trends in changing patterns of congestion.

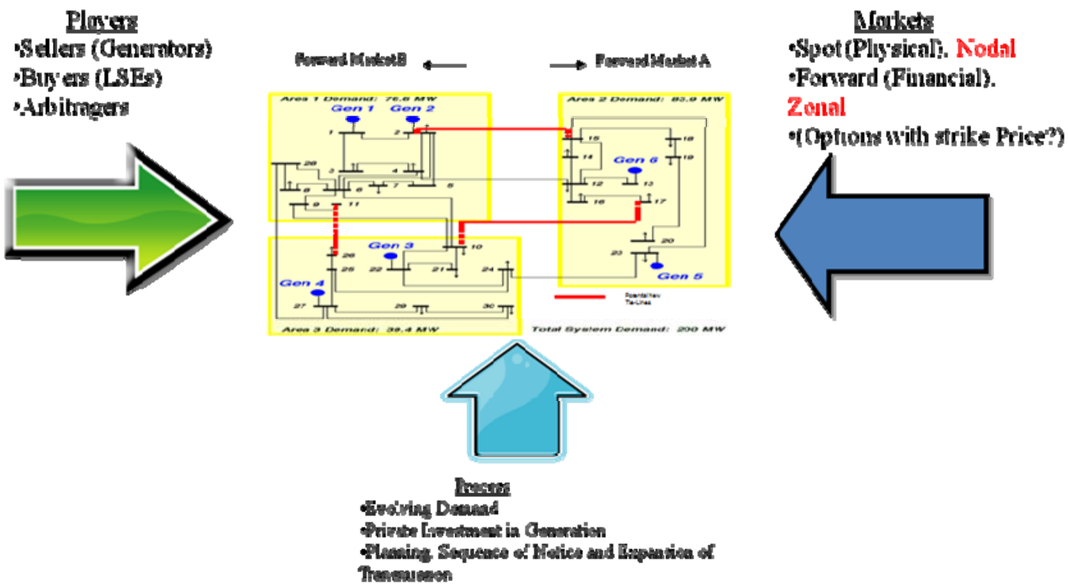

Figure 2, Experimental Design: Power Web 30 Bus (AC Network Model)

To test the impact of a dynamic market on planning, additional experiments would be designed, after the validity of the forward market test-bed described above had been demonstrated, that included announcements of the upgrading of transmission ties between the congested zones. The base case would have these transmission investments announced randomly when warranted by congestion. In contrast, other trials would use a preannounced process for transmission investment that would be laid out prior to actual investment decisions.

Section 4. Conclusions and Future Research

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 (EIPC) are already underway.

Thus far, in economic jargon, electricity markets are still “incomplete”, primarily in terms of having regularly conducted forward markets that are financial (voluntary and open to anyone). 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 prior analyses that should be performed include: 1) experimental tests of different sequencing of announced transmission investment upgrades with forward and spot markets, 2) determine 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. Longer shots include 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 with high penetrations of renewable sources of generation.

Section 5. Project Publications

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Appendix A.
Initial Summary of ISO/RTO Planning Activities: A Selected Comparative Overview

Fernando Alvarado

A.1. Introduction

This report summarizes a few of the prevailing regional planning philosophies along with some of the main results from applying these philosophies in several of the regional markets for electricity. All Independent System Operators have some mechanism for planning that attempts to resolve the issue of operating in a deregulated environment. All these planning philosophies have certain elements in common, while they address other issues in a specialized manner. This analysis concentrates on New England, PJM and MISO. Texas, California and New York will be added later on, time permitting. The information is current as of late 2006 and early 2007. Most of the information has been gathered from publicly available reports on the various web sites associated with the ISOs. In many cases, the comments attributed in the various descriptive sections are edited versions of comments made in the various reports, and in other cases they are copied verbatim from the source documents.[1] All documents used are publicly available in the corresponding web sites for the various ISOs.

All regions address the issue of providing sufficient future capacity in the system as well as issues of transmission versus generation expansion. A comparison of view is presented in a subsequent section, along with a final "critique" section. The comparative and critique sections are original material based on the material from the other sections.

A.2. New England Regional Planning Philosophy and Status

For planning procedures, see
http://www.iso-ne.com/rules_proceds/isone_plan/index.html

For plan details and updates to the plans, see
http://www.iso-ne.com/trans/rsp/index.html

ISO New England Inc. (NEISO) operates the bulk power generation and transmission system in the New England region; it administers the region's wholesale electricity markets and manages the comprehensive planning of the regional bulk power system.

Each year, NE ISO prepares a comprehensive 10-year Regional System Plan (RSP) that include forecasts of future load and how the system as planned can meet the demand by adding

[1] We will likely want to get permission from some of the ISOs prior to publication and dissemination of this document and/or we will want to make the "quotations" more explicit.

generating resources, demand-side resources, and transmission. The plans also include information intended to improve the design of the markets and the economic performance of the system. Most of the description that follows is based on NEISO's 2006 Regional System Plan (RSP06). The major findings of RSP06, taken from the reports and web sites cited above (verbatim, in most cases), are:

- Capacity—Additional installed capacity (ICAP) is needed in New England by 2009 to assure that the system meets its resource adequacy standard. The addition of fast-start resources in transmission-constrained areas would improve system security and reduce reliability costs to consumers. Environmental regulations will likely encourage the development of "clean" resources that will help meet system capacity needs.

- Fuel Diversity and Cost Considerations—The region relies heavily on natural gas to generate electricity. Therefore, the price of electric energy is linked to the price of natural gas. Having a fuel mix that includes adding baseload generators with low marginal production costs would help control consumer electric energy costs and reduce electric energy price volatility. Increased conservation, energy efficiency, and demand response would also help control costs and price volatility.

- Transmission—Transmission upgrades are required throughout New England.

The results of RSP06 show that New England will require new resources by 2009 across the system and specifically in major load pockets, especially Greater Connecticut and Greater Southwest Connecticut (SWCT). The specific amounts, locations, timing, and characteristics of these resource requirements will be influenced by improvements to the markets, new environmental regulations, the growth in demand, and transmission system constraints. Without additions, the region will fail to meet reliability criteria.

RSP06 emphasizes the importance and value of applying conservation, energy-efficiency, and demand-response to reduce demand. It also encourages the addition of fast-start generators needed for the economical and secure operation of transmission-constrained load pockets.

NEISO has designed and obtained approval from FERC for the Forward Capacity Market (FCM) Settlement Agreement. The FCM is designed to enhance system capacity. These enhancements include encouraging the development of new supply-side and demand-side resources, providing incentives to improve the availability of existing resources in times of greatest system need, and compensating participants that provide the needed resources. This market has been designed to encourage the development of fast-start and demand-response resources.

RSP06 emphasizes the critical importance of reducing the region's heavy dependence on natural gas and oil, particularly during winter peak-load conditions. Recent improvements in the electric energy markets should encourage the economic viability of contracts for gas supplies. According to RSP06, NEISO must consider also nuclear energy, renewable generation and new coal technologies.

The ISO conducted an electric energy and production cost-impact analysis of adding baseload generation (other than natural gas or oil fired) that has low marginal production costs. The results of the analysis show that consumers would have saved about one-half billion dollars in electric energy costs if 1,000 MW of this type of baseload generation had been added to the system in 2005 at prevailing capacity prices.

To illustrate the potential effects of reducing the consumption of electricity, the ISO analyzed the effects of demand reduction on the wholesale market. The analysis shows that reducing demand by 5% during all on-peak hours through energy conservation and energy-efficiency measures would have saved consumers the same amount on the basis of historical performance for 2005. *A critical step in reducing peak demand is linking the retail rate design with wholesale electricity pricing*.

NEISO continues to develop a number of major transmission upgrade plans. These plans have been designed to ensure the continued adequacy and reliability of the transmission system by reducing significant bottlenecks in transferring power into load pockets throughout New England and relieving the dependence on local generation within these pockets. The two most significant projects are the NSTAR 345 kV Reliability Project (Phase I) and the Southwest Connecticut Reliability Project (Phase 1).

Key RSP06 results are as follows.

The growth in demand drives the need to upgrade New England’s electric power infrastructure. New England’s summer-peak demand is projected to grow at a compound annual growth rate (CAGR) of 1.5% from 2005 to 2007 and 1.9%, or 500 MW to 600 MW per year, in the long run. These growth rates are, in part, a function of the price of electric energy, which reflects natural gas and fuel oil prices. These prices have sharply risen since 2000, but it is assumed they will decline and then stabilize over the long term. In addition, the region’s increased use of air conditioning is decreasing the annual load factor (i.e., the ratio of the average hourly load during a year to peak hourly load). This means that the peak hourly load has been increasing relative to average load levels. The annual load factor is expected to continue to decline to 54% by 2015, further indicating the need to add peaking capacity and demand response in the region.

Resources are needed within the next few years to provide sufficient systemwide capacity, as listed below. When properly sized and located, these resources can also provide critical system support in areas with limited transmission capability, particularly in import-constrained load pockets:

- With 2,000 MW of tie-line benefits, the system will need an additional 170 MW of capacity by 2009 to meet resource adequacy criteria.18 It will need 4,300 MW by 2015 with the same tie-line benefits. The system would need resources sooner and in greater amounts if not all of the assumed 2,000 MW of tie-line benefits were available or if generating units were retired. Projections of future amounts of tie-line benefits are currently under study and will be subject to stakeholder review. Consistent with planning criteria, the use of operating procedures for responding to a capacity deficiency would be required several times per year, despite the addition of needed capacity.

- Without adding new resources to the system, the frequency and severity of responding to a capacity deficiency would increase over time and vary with changes in demand and other factors. The examination of specific extreme load conditions shows that up to 1,700 MW of relief could be required in 2007 during a Capacity Deficiency. The ISO's reliance on neighboring systems would increase at the same time that these systems would likely have less capacity available to sell to New England.

- Greater Connecticut needs additional resources, transmission improvements, or a combination of both for reliable system operation and compliance with transmission planning criteria. If import limits into the area do not improve, by 2009 the area would need a minimum of 510 MW of new resources or a reduction in the peak demand of the same amount. This amount would grow to 1,440 MW by 2015. Adding these resources or reducing the load also would potentially defer the need for transmission improvements necessary for reliability.

- Locating generators near areas of relatively high demand provides the capacity needed to meet demand while minimizing the need for transmission expansion. While all generator interconnections are subject to system impact studies that address technical requirements, for enhancing reliability, adding generating units in southern New England (SNE), especially Greater Southwest Connecticut, is generally preferred to locating them elsewhere. Upon completion of the SWCT Reliability Project, the most preferred location for electrically interconnecting new resources will likely be the northern and western areas of the Southwest Connecticut 345 kV system. As demand continues to grow, locating new capacity in the BOSTON area also would assist in meeting total system capacity requirements. However, these interconnections would be subject to electrical system performance constraints.

Beyond needing a certain level of resources to reliably meet the region's demand for electricity, the system needs the type of resources that can quickly respond to system contingencies related to equipment outages and higher-than-forecast peak demand. These resources provide reserves for maintaining operational control and serve or reduce peak loads during periods of high demand. A lack of fast-start resources in transmission-constrained subareas could require the ISO to use more costly resources to provide these necessary services. In the worst case, reliability could be degraded.

NEISO has created the notion of a locational Forward Reserve Market (FRM). The FRM is intended to encourage the development of fast-start and demand-response resources in load pockets to meet these operating needs and reduce reliability payments. The most important FRM requirements are for Greater Southwest Connecticut, Greater Connecticut, and BOSTON. The actual required amounts will depend on operating conditions and requirements, which will change in accordance with the market rules.

A.3. MISO Regional Planning Philosophy and Status

For more details on Regional Planning within MISO, see
http://www.midwestiso.org/page/Expansion+Planning

For the specific planning report itself, refer to:
http://www.midwestiso.org/publish/Document/27851_11011a2ccaa_-7d000a48324a/MTEP06_Report_020507.pdf?action=download&_property=Attachment

MISO refers to its panning report as "MTEP" (Midwest ISO Transmission Expansion Planning). The Midwest ISO regional transmission expansion planning process has as its goal the development of a comprehensive expansion plan that meets both *reliability* and *economic* expansion needs. The Midwest ISO has among its obligations the independent verification that the Transmission System is being planned efficiently to meet reliability needs. MTEP 2006 is an evolution of MTEP 2003 and MTEP 2005.

The Midwest ISO regional transmission expansion planning process has as its goals the development of a comprehensive expansion plan that meets both reliability and economic expansion needs. The Midwest ISO Board of Directors has enumerated five planning principles:

1. Make the benefits of a competitive energy market available to customers by providing access to the lowest possible electric energy costs

2. Provide a transmission infrastructure that safeguards local and regional reliability

3. Support state and federal renewable energy objectives

4. Creates a mechanism to ensure investment implementation occurs in a timely manner

5. Develop a transmission system scenario model and make it available to state and federal energy policy makers to provide context and inform the choices they face.

Although the Midwest ISO recognizes the intertwined nature of traditional planning to meet reliability needs while at the same time providing expansions that maximize economic value to customers, as a result of the traditional expansion planning paradigm, the Midwest ISO (MISO) Transmission Expansion Plan (MTEP) process is currently bifurcated into two distinct areas for assessment. These two assessment areas are: planning to meet reliability needs, and planning for economic expansions, which are considered by many to be distinct processes. It is often stated that reliability driven expansions are "mandatory", while economic expansions are "optional" or discretionary.

The current MTEP plan builds on the previous two regional plans and incorporates the following:

1. Validation of all planned transmission projects to ensure they are needed and to determine if they are eligible for regional cost sharing. This is an important requirement since regional cost sharing is now in place as a result of the February 2006 FERC Order accepting MISO's Phase I Regional Expansion Criteria Benefits (RECB) filing.

2. Continued development of expansions that lay the foundation for a set of economic projects that may be justified in the future as supplements to or in some cases replacements for some of the projects proposed as reliability expansion in this or subsequent plans. The objective is to ensure that sufficient transmission capacity is constructed so that a competitive wholesale energy market can flourish.

3. Incorporation of the five guiding principles from the Board of Directors into the planning process.

MTEP 06 process was guided by the Board's Planning Principles but was also heavily influenced by the requirements of the new regional transmission cost sharing tariff approved by the FERC in February of 2006, which called for the following elements to be addressed:

- Initial Identification of Reliability Needs
- Optimization of Reliability Solutions
- Identification of Opportunities for More Efficient Dispatch
- Identification of Commercially Beneficial Regional Expansions
- Expectations of FTR Coverage

The reliability testing of the planned system is focused at ensuring there is sufficient transmission capacity to serve the expected load under the highest demand conditions. Thus most reliability testing is of a peak load power flow model that has a specified generation dispatch. The dispatch the Midwest ISO applies to establish Baseline Reliability Projects is referred to as a "contractual" dispatch and is representative of an economic dispatch of each LSE's owned and firm contractual resources on an LSE basis. This dispatched is based on the dispatch reflected by LSE's in developing the NERC planning models. This is not the most efficient dispatch that might be desirable under market operations, however, it provides the basis for expansions necessary to allow each LSE to reliably and efficiently deliver its own resources to its load. It is also a dispatch that is expected to best ensure the simultaneous feasibility of FTRs.

The contractual dispatch applied to determine reliability upgrades is not the most efficient dispatch that might be desirable under market operations. Such an unconstrained dispatch would require additional upgrades and the value of these upgrades in reducing customer costs need to be evaluated against their costs in the market efficiency planning process. The Midwest ISO is beginning to address these market efficiency issues.

Reliability

An integral part of the MTEP 06 analyses was the testing of the system for compliance with reliability standards with all planned and proposed projects in place. This was referred to as the "Phase 3" model testing. This testing demonstrated that if all Planned and Proposed projects listed in Appendices A and B with expected in service dates prior to 2012 are implemented by 2011, the system will perform within NERC reliability standards, with the following exceptions. There were some remaining low voltage conditions on the 161 kV system identified by the Midwest ISO for the SIPC system in the Central region. Similarly, in the East region there were some relatively minor low voltage conditions identified on the 138 kV systems on the First

Energy, METC, and Wolverine Power systems. These issues are not expected to be a concern in the immediate future and will be monitored for solutions.

Market Efficiency

The energy market planning analysis portions of the MTEP 06 study examined the market performance of the 2011 baseline reliability plan by examining constraints to cost effective delivery of energy to the market. The exploratory portion of the energy market planning analysis also considered state policy objectives, delivery of large blocks of future generation from the generation interconnection queue by integrating the past exploratory studies with studies of our members and refining the plans using energy market economic analysis. The intent of energy market analysis is to identify constraints to efficient delivery of resources to the market and develop transmission solutions for further analysis and potential inclusion in future MTEP as Regionally Beneficial Projects.

The top 30 binding constraints occurring in market operations during 2006 were reviewed, and compared to a 2011 market simulation. This analysis revealed that 22 of the 30 top binding constraints are not expected to be significant constraints in the 2011 model. Below we give the tables directly from MTEP 06 with this information.

Specific Plan Highlights:

- $2.1 billion in committed projects by participating Transmission Owners through the year 2011 and forecast of an additional $1.5 billion for the same period

- Elimination of 22 of the top 30 constraints to market Operations

- Four new expansion plans specifically addressing constraints in the newly identified Narrowly Constrained Area in Eastern Iowa and Minnesota, additional analysis needs to be performed to determine whether these projects completely alleviate the concern.

- Facilitation of new generation entry by providing expansions to accommodate 14,400 MW of new generation supply, 5,100 MW of which is base load supply and 2,810 MW of renewable resources through 2011.

- Provision for footprint-wide expansions at all transmission voltage levels including commitments for three new 345 kV and two 230 kV lines for service by 2011.

A.4. PJM Regional Planning Philosophy and Status

For more details about the PJM planning and planning process, see
http://www.pjm.com/planning/reg-trans-exp-plan.html

PJM's Regional Transmission Expansion Planning (RTEP) process integrates transmission, generation and demand-side resources to address transmission system constraints involving reliability and persistent congestion. The result is one RTEP that responds to many system drivers, including:

- Forecasted load growth, demand-side-response efforts and distributed generation additions
- Interconnection requests by developers of new generating resources and merchant transmission facilities
- Solutions to mitigate persistent congestion and forward-looking economic constraints
- Assessments of the potential risk of aging infrastructure
- Long-term firm transmission service requests
- Generation retirements and other deactivations
- Transmission-owner-initiated improvements
- Load-serving entity capacity plans

In addition to its "stand alone" RTEP, PJM coordinates closely with MISO for their joint transmission activities. The RTEP process for PJM is clearly reliability-driven, and it is divided into a short-term process, looking at the next five years, and a long-term analysis, focusing out to 15 years ahead.

PJM's five-year planning enables PJM to assess and recommend transmission upgrades to meet near-term demand growth. This includes electricity from both existing generation and new resources arising from interconnection requests by developers. The five-year component of PJM's RTEP includes the following:

1. Solutions to address baseline transmission constraints revealed by reliability criteria violations observed in power-flow and related studies
2. Cost responsibility allocations for baseline reliability upgrades
3. Direct connection, transmission enhancements associated with generation and merchant transmission interconnection requests
4. Necessary network transmission enhancements in response to interconnection requests

During 2006 the PJM Board approved the following major upgrades to address key reliability issues identified through 2011.

1. A new 502 Junction - Mt. Storm-Meadow Brook-Loudoun 500kV transmission line is needed to avoid reliability criteria violations in 2011. These violations include potential line overloads and voltage problems. Extensive analysis of various options yielded a recommendation for this new line from western Pennsylvania to feed the Northern Virginia area-Washington, D.C.- Baltimore-Maryland area and other load centers. This area of PJM

continues to experience significant economic growth, growth that requires access to additional sources of electricity and the transmission infrastructure to provide it.

2. A new Carson – Suffolk 500 kV circuit, second Suffolk 500/230 kV transformer and new Suffolk – Fentress 230 kV circuit are needed to mitigate the potential loss of load in the Norfolk / Virginia Beach area of Dominion for the outage of the two 500 kV circuits that serve the area. Various system upgrades have been included in the RTEP to support this area for reliability criteria violations observed in 2009 and 2010. However, by 2011 the total post-contingency loss of load in the area exceeds 400 MW. PJM is therefore recommending the addition of the Carson – Suffolk 500 kV circuit and associated upgrades to resolve this potential loss of load issue.
3. A series of upgrades in northern New Jersey including three 230 kV line reconductoring upgrades and several 230 kV circuit breaker replacements for 2011 are required in lieu of a new 230 kV circuit from Linden - South Waterfront under-water 230 kV cable. This circuit was not expected to be completed by 2011 (its original estimated completion date). However, its development will continue based on the expectation that it may be required to resolve criteria violations that may result from a number of potential issues including new merchant transmission facilities to New York City and Long Island and the deactivation of additional of generation in northern New Jersey
4. 500/230kV transformer upgrades, replacements and additions, are needed at Brighton, Bristers, Burches Hill, Conastone, Dooms, Doubs, New Freedom, Red Lion and Waugh Chapel. New 500/138kV transformers at Wylie Ridge and a 765/138kV transformer at Amos are needed as well. In addition, new substations and 500/230kV transformers are also needed at Alloway and Center Point in order to ensure energy delivery to meet load requirements. Overall, power flow analyses reveal that additional west to east power transfers to serve growing load are driving higher loadings on 500kV and 765kV step-down transformers.
5. Based on the results of an aging infrastructure Probabilistic Risk Assessment (PRA) performed for PJM's 500/230 kV transformer fleet, seven new spare transformers have been approved by PJM's Board and incorporated into RTEP to enhance system reliability and to mitigate congestion costs in the event of a transformer failure. PRA analysis has identified a congestion risk exposure of $74 million, annually, that will be largely mitigated by the deployment of these spare transformers. A standard specification has also been developed for the 500/230 kV transformer fleet to be utilized in the procurement of new transformers.
6. Over 2,700 MVAR of additional reactive power sources by way of new capacitive reactive devices at substations across PJM are required to mitigate identified voltage criteria violations encountered as a result of supporting delivery of energy to eastern PJM load centers.

The 15-year component of the RTEP permits consideration of long-lead-time transmission options. This type of planning addresses long-term load growth, the impacts of generation retirements, and the delivery needs of "clustered" generation development emerging in PJM. This includes large base load Midwest coal projects, nuclear generation in Maryland and Northern Virginia, Appalachian Ridge wind farms, and natural gas pipeline access projects.

Working with the federal Department of Energy, PJM also has filed for the designation of National Interest Electric Transmission Corridors (NIETC) in three areas to facilitate such multi-state projects.

Through December 31, 2006, PJM has identified the following reliability issues developing within PJM that must be addressed by the implementation of long lead-time transmission facilities:

1. Eastern PJM (New Jersey-Southeastern Pennsylvania-Delmarva Peninsula) - continued load growth, retirement of generation resources, sluggish development of new generating facilities and continued reliance on transmission to meet load deliverability requirements and to obtain access to more economical sources of power west of this area, are collectively and progressively diminishing system reliability in eastern PJM:

    - Planning studies identified 17 overloads, the majority of which are on the 230 kV system and occur from 2015 through 2021. And, while PJM's current RTEP includes upgrades needed to address two identified merchant transmission interconnection requests (the Neptune project and the East Coast Power VFT project), system reliability issues already identified in eastern PJM between 2015 and 2021 will be compounded by additional system stress from additional exports to New York City and Long Island. PJM is presently assessing the potential for this as the result of two additional merchant proposals presently active in PJM's interconnection queues.
    - The status of potential deactivation of units in eastern PJM and northern New Jersey in particular will continue to be monitored by PJM. As generating units continue to advance in age (a number of which are already 40 or more years old) and as environmental concerns continue to grow, PJM will continue to monitor deactivation decisions by generation owners.
    - Increasing power transfers to feed eastern PJM load centers by way of Pennsylvania were observed in studies to cause overloads in 2019 and 2020 on three 500 kV circuits that cross PJM's Western and Central interfaces. These will also require mitigation.

2. Allegheny Mountain Corridor. The system reliability trends that have emerged in Eastern PJM have emerged in this area of PJM as well. This area faces growing customer demand (1.9 % annually in Dominion alone), generator deactivations, sluggish generating resource additions and reliance on transmission system facilities to import power. The electricity needs of the Washington-Baltimore-Northern Virginia area are supplied not only by local generation, but also by high volume energy transfers into the area across the bulk power transmission systems of northern West Virginia, Northern Virginia area, Maryland, eastern Ohio and central-southwestern Pennsylvania. As a result, baseline reliability analyses since 1999 have revealed consistently the need to address the ability of the generation and transmission resources in those areas to continue to serve load reliably. The first overloads observed in 2011 have led to the approval of the 502 Junction-Mt. Storm-Meadow Brook-Loudoun 500kV transmission line. Throughout this corridor other overloads were also observed in 2014 and beyond for which PJM will continue to pursue other new much-needed backbone transmission lines.

3. Delivering new generation in Maryland and Virginia to load centers north and east - The anticipated development of a cluster of base load nuclear-fueled generation in Virginia and south of Baltimore - totaling potentially 4,800 MW - will require transmission enhancements to ensure reliable delivery to load centers north and east.
4. With the Board-approved 502 Junction-Mt. Storm-Meadow Brook-Loudoun 500kV transmission line now part of PJM's RTEP, elements from a number of other transmission options have been considered to resolve reliability criteria violations through 2021. PJM has narrowed the group of alternatives for further consideration to the seven line segments shown on MAP 1.3.

Overall, PJM's body of analysis through December 31, 2006 has revealed the following general conclusions that will help guide selection of a final package of upgrades for submittal to and approval in 2007:

1. The alternatives that provide a source into Roseland provide a significant benefit to mitigate overloads in northern New Jersey.

2. The alternatives that provide a source into Deans or Salem provide minimal benefit for mitigating overloads in northern New Jersey.

3. The three proposed lines that terminate at South Canton, Kammer and Amos in western PJM each mitigate the remaining reliability criteria violations identified in the 15-year horizon.

4. From a market efficiency perspective, alternatives that connect back to the AEP 765 kV system provide the greatest opportunity for eastern load centers to access additional economical energy from western generating resources

The PJM Board has endorsed PJM's plan to pursue a number of parallel technical analyses and market efficiency analyses. Technical analyses will assess each proposed line's need for and extent of required underlying supporting facilities and will examine the ability of each line to integrate developing clusters of generating projects within PJM. These include a cluster of anticipated new nuclear units in southern Maryland and northern Virginia as well as clusters of new coal generating resources in Central Pennsylvania and in the Ohio/ West Virginia/ Kentucky area. Final identification of a package of upgrades will be based on the outcome of all technical and market efficiency analyses.

Reactive power planning is also an integral part of the PJM planning process. Initial 2016 study results have revealed the need for approximately 9,000 MVAR of reactive devices by 2016 in the Mid-Atlantic area of PJM to provide an adequate voltage profile under 'n-0' and 'n-1' system contingency events. Coupled with 1,000 MVAR of reactive capability planned by PJM Transmission Owners as part of the base system model update for 2016, over 10,000 MVAR of reactive devices are required prior to 2016. These results will continue to be evaluated taking into consideration the impact of proposed backbone transmission projects

To account for *economic growth uncertainty*, PJM studied load forecast deviations amounting to a 2% load forecast increase by year ten. Generally speaking, power flow results revealed that overloads identified in years six through ten would be advanced by a year or two. Because system upgrades to resolve problems identified in years six through 15 (absent a 2% load forecast increase) will not be determined until early 2007, refinement of required in-service dates for such upgrades based on these sensitivity study results will be factored-in at that time.

The *effect of circulation* (or loop flow) was assessed on PJM's 2011 RTEP base case. Preliminary results indicated the potential for four overloads in the ComEd territory. PJM is working with ComEd to finalize these results. No other problems were identified.

A *generation scaling* sensitivity study was also completed. That study modeled all generation with an Impact Study and not withdrawn from PJM's interconnection process in addition to generation in–service or that has an executed Interconnection Service Agreement. Analyses completed through 2006 revealed that the majority of overloads after 2018 are accelerated by two years. PJM does not plan to accelerate any system upgrades at this time because recommended system upgrades to resolve the reliability issues identified in years six through 15 are not expected to be determined until early in 2007. Refinement of the required in-service date based on sensitivity study results will be factored-in at that time.

A.5. Joint PJM-MISO Regional Planning philosophy and status

The primary purpose of the MISO-PJM Coordinated System Plan (CSP) planning process is to contribute, through coordinated planning, to the on-going reliability and the enhanced operational and economic performance of the systems of the parties. To accomplish this purpose, the CSP shall:

- Integrate the Parties' respective transmission plans, including any market-based additions to system infrastructure (such as generation or merchant transmission projects) and Network Upgrades that were considered.
- Set forth actions to resolve any impacts that may result across the seams between the Parties' systems due to such system additions or Network Upgrades; and
- Describe results of the joint transmission analysis for the combined transmission systems, as well as the procedures, methodologies, and business rules utilized in preparing and completing the analysis.

As established in the "Joint Operating Agreement (JOA) Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C," coordinated regional transmission expansion planning across the seams will reduce congestion on an inter-RTO basis and enhance the physical and economic efficiencies of congestion management. Under the JOA, Midwest ISO and PJM have agreed to coordinate the results of their respective transmission expansion planning processes in order to establish inter-regional planning.

PJM has responsibility for the development of a Regional Transmission Expansion Plan (RTEP) for the PJM system that will meet the needs of the region in a reliable, economic and environmentally acceptable manner. PJM also is responsible for recommending the assignment of any transmission expansion costs to the appropriate parties. In order to carry out these responsibilities, it is necessary to establish a starting point or ‘baseline’ from which the need and responsibility for enhancements can be determined.

The Midwest ISO regional transmission expansion planning process (MTEP) has as its goals the development of a comprehensive expansion plan that meets both reliability and economic expansion needs. The Midwest ISO has among its obligations the independent verification that the Transmission System is being planned efficiently to meet reliability needs.

In order to establish that baseline, Midwest ISO and PJM defined the 2011 Summer Peak year as the “baseline” planning period for the purpose of the CSP. The base system consists of the existing systems plus any planned modifications to the transmission systems scheduled to be in service prior to the 2011 summer peak period. All new generation and merchant transmission projects in the MTEP and RTEP processes that executed an Interconnection Service Agreement (ISA) were also included in this base system. In addition, the base system includes any associated transmission enhancements as identified in the Impact Studies associated with those projects. Any Transmission Owner identified (TOI) transmission enhancements independent of those associated with new generation or merchant transmission projects were also included. Only firm transmission service currently committed for the period was represented.

The load flow analysis that was completed for the CSP study is a subset of the following reliability criteria:

- NERC Planning Standards
- Regional Reliability Organization
- Local Transmission Owner Criteria

The key findings of the joint planning between MISO and PJM are:

- N-2 contingency analysis on PJM and Midwest ISO facilities 345kV and Midwest ISO greater identified several constraints within both Midwest ISO and PJM systems. But reasonable re-dispatch solutions were identified to address the N-2 constraints

- RTO standard deliverability test monitoring each others system

    - MISO to MISO Generator Deliverability analysis (monitoring PJM system) did not show any new cross border constraints that would limit deliverability of existing Midwest ISO Network Resources

    - PJM to PJM Generator Deliverability analysis (monitoring MISO system) indicated one new potential cross-border constraint (Lanesville 345/138kV Transformer in Ameren/CILC) that would limit deliverability of existing PJM Network Resources

- Common Generator Deliverability analysis tested the combined deliverability of both Midwest ISO and PJM network resources to the combined Midwest ISO and PJM footprint. Note that the driver for the combined deliverability study is the JCM filing and the results are reported only as first hand information in order to support further discussion of potential joint deliverability policies. This test revealed several constraints within both MISO and PJM system limiting the combined deliverability of network resources (NR) within the combined footprint. However, a large majority of the existing NR passed the combined deliverability test. The deliverability test primarily tests if generation capacity could be delivered out of the generation area without being “bottled-up”. Even though the combined deliverability test indicates that a large majority of the NRs may be deliverable to the combined footprint, constraints limiting inter-regional transfers should also be recognized in a combined deliverability analysis over a wider combined footprint. Further discussions within the stakeholder communities will determine how to interpret the results and to plan the next steps of the combined deliverability analysis.

A.6. Comparative Discussion and Summary

All the systems examined have in place regional planning processes. The outlook forward for these plans varies from a short-term horizon of 5 years to a long-term horizon of 15 years. All systems have stakeholder representation in the process. There are attempts to formally coordinate the expansion of neighboring systems. The detailed expansion plans tend to be derived in all cases from actual or anticipated operational problems and the possibility of reliability degradation.

The cost sharing arrangements within the MISO seem to be instrumental in having provided sufficient additional incentives for many projects to move forward. Systems without this shared set of incentives seem to be more hampered by their ability to put projects forward.

A.7. Critique and Commentary

Clearly, the various ISOs have in place procedures for system expansion that address some of the most prominent problems. Systems such as New England go about the process from a more or less traditional engineering vision and evaluation of system needs, and subsequently address how markets will impact (either help or hinder) the expansion decisions. PJM begins with the notion that in general the markets will perform many but not all of the expansion tasks that the system will require, and focus instead on supplementing and enhancing the market responses with suitable additional incentives and/or ISO-funded reliability projects that are seen as not resulting from natural market action. MISO give reliability a “mandatory” status, but fully considers economics in its expansion needs analysis, and makes extensive use of cost sharing arrangements.

Appendix B.
Summary of Executive Forum on Planning, Markets and Investment (PSERC Report 09-01)

Richard E. Schuler

A one day forum emphasizing a dialog among the 23 senior electricity industry managers who participated was conducted by PSERC to focus on the role and structure of planning needed to elicit required investment. The participants were divided into five groups, each of which was charged with devising a preferred planning process for their own members who were aligned according to similar institutional, economic and geographic circumstances within each group.

While all agreed that planning was absolutely essential in this industry, differences emerged on virtually every other aspect, ranging from the proper time horizon (from 5-10 year to 10-20), whether the planning should be incremental or evaluate fundamental system re-design (e.g. overlays of higher voltage grids), who should pay for transmission expansion (the beneficiaries, only, vs. everyone) and the scope of the planning (electricity only, integrated energy resource planning, or adding area economic and environmental impact criteria). However, as suggested by the convener in his concluding observations, most of these differences do align according to the differing institutional, economic and geographic environments in which the individual managers operate, and if there is sound reason for those historic differences, there may be a valid reason to have different planning procedures in these different regions.

But all participants did acknowledge the absolute necessity of conducting long-range planning for the electricity supply industry, plus the need for better demand forecasting and more advanced electric system simulation and planning tools. The participants also agreed that the following three institutional advances would greatly improve planning processes, regardless of individual regional differences in the nature and scope of that planning:

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.
3. Mechanisms to value a “negawatt” that encompass differing certainties of demand response as compared to “iron-in-the ground” supply responses to planning.

Finally, in brief presentations at the beginning of the forum that emphasized investment incentives, one author described the wide array of technological innovations that the industry may need to accommodate in its future planning, a second described the efficiencies to be obtained by a fundamental rescaling of transmission technology across a region, and a third presenter emphasized how proper locationally-differentiated markets do provide the right incentives to build the right thing at the right place (incrementally). The initial presenter, however, reminded the forum of the need to align investment decisions with bearing the responsibility for their consequences, both costs and benefits. To paraphrase: people often spend other peoples’ money very differently than they would their own.

Appendix C.
Description and Results of Experimental Trials of the ISO-NE Forward Capacity Market[2]

Timothy D. Mount and Surin Maneevitjit

The main question addressed in these exercises is whether the economic incentives provided in a capacity market will give the right incentives to get the right type of new capacity built to move the mix of generating capacity towards the economically efficient mix. The capacity market run by the New York Independent System Operator (NYISO) has some obvious deficiencies (prices can be manipulated by the incumbent firms and the market clears too close to real time to make it feasible for potential new firms to participate). As a result, the paper focuses the Forward Capacity Market (FCM) proposed by regulators in New England. As the name suggests, the FCM purchases capacity three years ahead of real time, and as a result, potential new entrants can participate and build a new unit only if their offer price is accepted in the auction. In addition, the offer prices allowed for incumbent firms are severely restricted. If an offer for a new unit sets a high price, all capacity is paid this high price but existing capacity can not set a high price.

A series of economic experiments were conducted to test the performance of the FCM using graduate students at Cornell University to represent incumbent firms and software agents to represent potential new entrants. In the first test, there was only one type of generating capacity in the market. The incumbent firms were successful in 1) maintaining market share and keeping out new entrants by undercutting the cost of building a new unit (gains in wholesale market earnings were more than enough to offset the loss in building a new unit), and 2) creating artificial scarcity using legal ways to withhold capacity and therefore allow a new unit to set a high price (by repowering existing units, for example).

In the second test, there were two types of generating capacity, peaking and baseload. The earnings of baseload units in the wholesale market depended on the amount of time that peaking units set the price. Consequently, the earnings of an installed baseload unit will increase if higher loads are met by building new peaking units. Even though the profits are very high for an installed baseload unit, the results show that the incumbent firms have no incentive to build new baseload units if new entrants can only build new peaking units. The incumbent firms will not reinvest their profits in new capacity unless potential new firms can build new baseload units, and therefore, make low offers to build new baseload units that take into account the earnings in the wholesale market. Hence, institutional barriers to entry associated with the safety of nuclear plants and environmental restrictions on emissions from coal plants may undermine the performance of the FCM given the current high prices of natural gas.

[2] This appendix is a paper that was presented at the IEEE 41st Annual HICSS Conference in January 2008 and the discussion in the introduction represents the state of the existing capacity markets at that time.

C.1. Background

The evidence to date about the performance of deregulated electricity markets is not encouraging for the advocates of deregulation. The energy crisis in California in 2000/01 is the most obvious example of a market design that failed and ended up increasing the cost of electricity for many customers in the western states. Although the California crisis was limited to the western states, there is more recent evidence that all deregulated regions in the nation are having trouble getting investors to commit to building new generating capacity when it is needed. A recent report by the North American Electric Reliability Council (NERC) summarizes the current outlook for maintaining reliability in terms of the capacity needed for both generation and transmission in different regions ("2006 Long-Term Reliability Assessment", NERC, October 2006). Four regions have adopted some form of deregulation (ERCOT (Texas), MRO (Midwest), NPCC (Northeast), and RFC (PJM)), three regions are still governed by traditional regulation or public power like the TVA (FRCC (Florida), SERC (Southeast), and SPP (South)), and the Western Inter-Connection (WECC) includes a combination of deregulation (California) and public power in the Northwest (Bonneville).

A comparison of the projections of the margins for generating capacity for the regulated and deregulated regions shows a remarkable difference. In the four deregulated regions, the 2006 projections of the capacity margin fall from the current level of about 15% to below 5% by 2015 in three regions and to less than 10% in the Northeast (NPCC). In contrast, the 2006 projections in the three regulated regions are relatively level at about 15% in two of the regions, and fall to less than 10% by 2015 in one region, the South (SPP). The projection for the West (WECC) is very similar to the situation in the deregulated regions and it falls below 5% by 2015. Comparing the projections made in 2003 and 2006 shows that the recent 2006 projections in the deregulated regions are substantially lower than they were in 2003 in two regions and about the same in the third region (there is no 2003 projection for PJM (RFC)). In contrast, the 2006 projections in the regulated regions are roughly the same in two regions and substantially higher in the third region (Southeast (SERC)). The projections for the WECC are like the deregulated regions, and the projection is much lower in 2006 than it was in 2003.

An important difference between regulated and deregulated markets is that the revenues received by generators in a regulated market are tied to actual costs. In a deregulated market, a large part of the net-revenue earned above the operating costs is fungible and does necessarily go towards the capital costs of generating capacity in a particular region. This problem is exacerbated by the fact that generators receive revenue from more than one market. In New York, for example, generators participate in markets for electricity, ancillary services and capacity. The capacity market was designed by the state regulators specifically for the purpose of encouraging investors to build new generating capacity when it is needed.

There is no general agreement among regulators on whether the earnings in a deregulated wholesale market for electricity should be sufficient to cover both operating and capital costs. Regulators in Australia, Alberta and Texas, for example, support "energy only" markets that cover all production costs and provide the financial incentives needed to get new generating units built when they are needed. In contrast, the deregulated markets in the northeastern and mid-Atlantic states provide generators with supplementary payments above their earnings in the wholesale market. These supplementary payments are designed to correspond to the shortfall anticipated by regulators in the net-revenue needed to cover capital costs.[3] The Independent System Operators (ISO) in New England, New York and PJM advocate using a capacity market to provide this supplementary revenue. However, there is still no general agreement among regulators about the best design for a capacity market.

The challenge for regulators in an energy-only market is to make sure that high prices above the true marginal operating cost occur infrequently and to avoid the type of market "meltdown" experienced during the energy crisis in California in 2000/01. A proposal for the new market design in Texas is to monitor the cumulative net-revenue earned by a proxy peaking unit in the wholesale market during a year. If this net-revenue gets above a specified level, related to the amount needed to cover the annualized capital cost of a Peaking unit, the market rules are changed for the rest of the year and a relatively low price cap is imposed on the market. The most important implication is that the regulators are using Long-Run Marginal Cost (LRMC) pricing to judge the market's performance. In other words, the wholesale market is considered to be competitive by regulators if the annual net-revenue earned in this market is sufficient to cover all of the production costs of a Peaking unit.

Regulators in the northeastern states and PJM have not supported the rationale for LRMC pricing in an energy-only market and have established a more traditional approach using Short-Run Marginal Cost (SRMC) pricing to judge the performance of a wholesale market. Given this criterion, wholesale prices should be equal to the true marginal operating costs at all times unless there is a genuine lack of available generating capacity to meet the system load. However, this is a difficult policy to implement because the structure of electricity markets makes it almost inevitable that some suppliers will speculate by submitting offers to sell that are well above the SRMC. As a result, regulators have implemented additional restrictions on the behavior of suppliers by using, for example, Automatic Mitigation Procedures (AMP) to discourage speculation. To a large extent, they have been quite successful in their efforts to reduce the number of price spikes in these wholesale markets compared to the period immediately after the markets were first deregulated. Figure 1 shows how the behavior of wholesale prices has changed in New York City.

This appendix is a paper that was presented at the IEEE 41st Annual HICSS Confere[4] The Demand Curve is specified in terms of "Unforced Capacity" (UCAP) to account for different levels of operating reliability for different types of generating unit. The UCAP is equal on average to 94.58% of the "Installed Capacity" (ICAP).

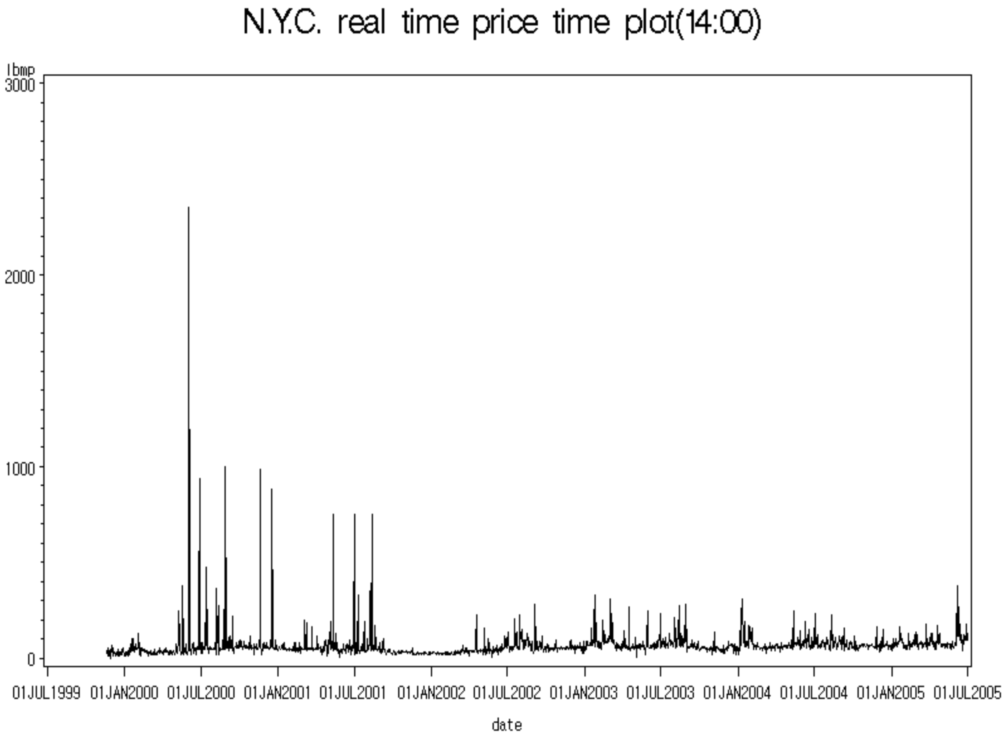

Figure C.1. Daily Zonal Wholesale Prices ($/MWh) for NYC in the Balancing Market at 2pm

An important consequence of reducing the number of price spikes in the wholesale market is to introduce the problem of missing money for generators, particularly the owners of Peaking units. This is true even though the evidence to date shows that wholesale prices are still above SRMC. The approach favored in New England, New York and PJM is to modify the structure of an Installed Capacity (ICAP) market to ensure that generators receive enough additional income to cover the missing money. Although most system operators recognize that some supplementary income for generators is needed with SRMC pricing, there is no general agreement about how much income is needed and how this extra income should be provided. The capacity market adopted in 2003 by the New York Independent System Operator (NYISO) provides the most extensive source of evidence to date about how well a specific form of capacity market works. The performance of this market has been disappointing in terms of getting new generating capacity built when it is needed. This poor performance is likely to be a major reason why the new market designs proposed by the Independent System Operators in New England (ISO-NE) and PJM are substantially different from the design of the ICAP market operated by the NYISO.

Minimum amounts of installed generating capacity are determined by the NYISO for three different regions in the Locational Installed CAPacity (LICAP) market.(3) For each region, the regulators specify an explicit “demand curve” for purchases in the capacity market three years in advance. However, this demand curve is only implemented one month ahead of the time when the capacity is needed. The economic rationale for the demand curve is to ensure that the price paid to generators for making their generating units available to meet load is enough to cover the prorated annual capital cost of a Peaking unit. If the amount of capacity purchased is less (more) than the amount required for reliability, the price paid for capacity will be higher (lower). Consequently, when there is not enough generating capacity to meet reliability standards, the price of capacity will be high. Regulators assumed that expectations about future outcomes in the capacity market would provide sufficient incentives for investors to build new generating capacity. In reality, if there really is insufficient capacity offered into the capacity market to meet reliability standards, it is much too late to build new capacity only one month ahead of the time when it is needed.

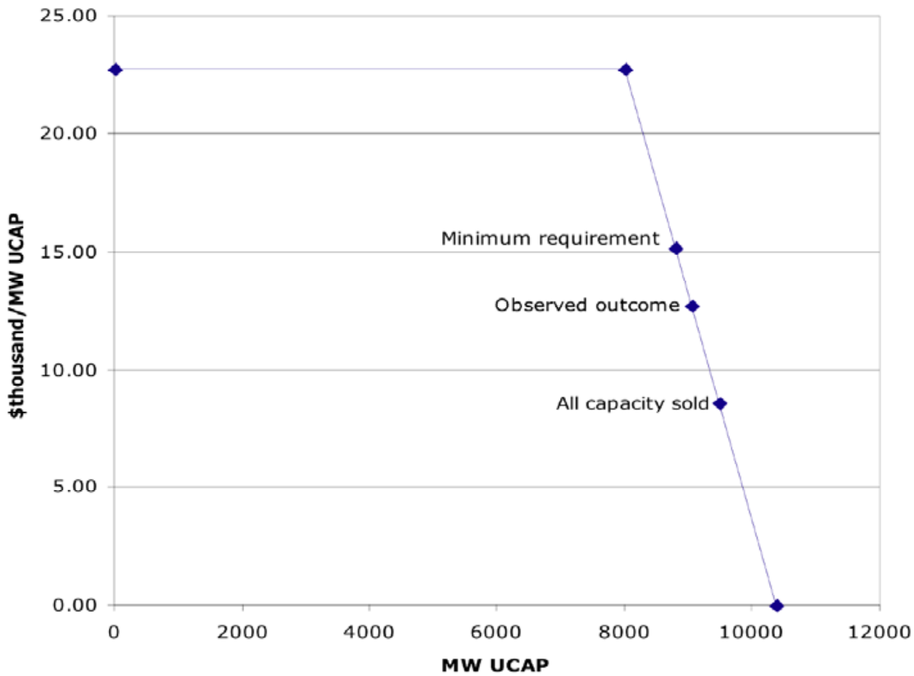

Figure C.2. The Spot Market Capacity Demand Curve for New York City Set by Regulators for June 2006

An example of the Demand Curve for generating capacity in NYC is shown in Figure 2 for June 2006. It is calibrated to pay the prorated capital cost of a Peaking unit at the "Minimum Requirement" needed to meet the reliability standard (8798 MW UCAP[4]). If all of the installed capacity (9843MW UCAP) had been sold, the market price would have been $8,600/MW (All Capacity Sold in Figure 2). However, the actual market price was $12,712/MW because only 9054MW UCAP were sold (Observed Outcome in Figure 2). Why did this happen? The answer is simple. Some firms get paid more money for selling less. The income from selling all capacity (9843MW UCAP at $8,600/MW) is $82million/month, compared to the actual outcome (9054MW UCAP at $12,712/MW) of $115million/month. The difference of $33million/month is substantial and corresponds to a 40% increase of the total cost of purchasing the capacity.

Even if many of the firms in NYC submit all of their capacity into the auction, it is still perfectly rational for the largest firms to withhold some of their installed capacity from the auction. In fact, the market price and the total cost would be even higher if the regulators had not introduced additional restrictions on how high the market price could be set by the largest firms. These firms are able to manipulate the market price to get exactly the amount that they are allowed. By setting a price cap on the incumbent firms, regulators have set an arbitrary limit on how much market power is allowed in the capacity market. In other words, the regulators

[4] The Demand Curve is specified in terms of "Unforced Capacity" (UCAP) to account for different levels of operating reliability for different types of generating unit. The UCAP is equal on average to 94.58% of the "Installed Capacity" (ICAP).

consider that a payment of almost $700million over the summer (assuming the price cap is paid to all capacity sold) is an acceptable amount to pay to incumbent firms for being available to generate electricity. If regulators had wanted the generators to offer more capacity into the auction and lower the price of capacity, they could have implemented different rules on behavior by, for example, requiring firms owning more than 1000MW UCAP to submit all of this capacity at a minimal price and be price-takers in the market.

Figure 3 shows the estimated earnings for combined-cycle and combustion turbines in NYC, LI and the upper Hudson valley for 2002-04. These estimates show that total earnings in NYC and LI are well over $100,000/MW/year for combustion turbines and well over $200,000/MW/year for combined- cycle turbines. Furthermore, a large part of the earnings in NYC and LI comes from the capacity auction, and for combustion turbines, the payments for capacity are the dominant source.

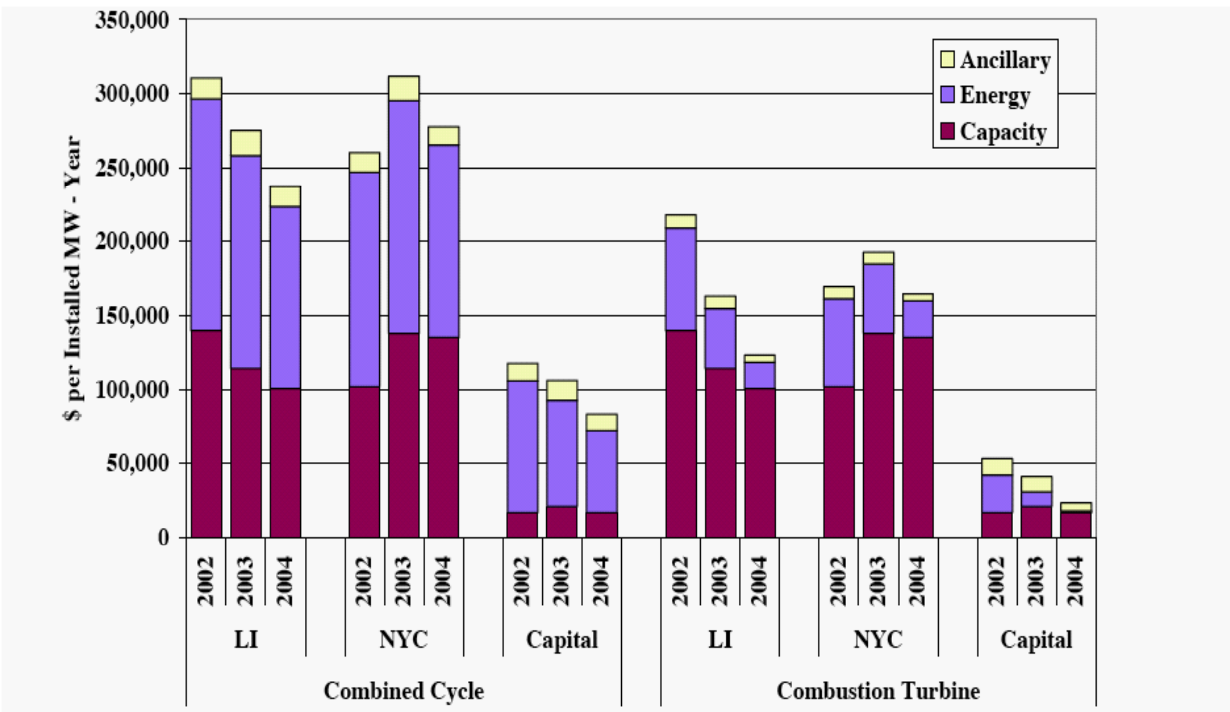

Figure C.3. Estimated Earnings (Net-Revenue) of Combined Cycle and Combustion Turbines in Different Locations in the NYCA ("Capital" is the upper Hudson valley).
Source: [13] Figure 16 on p. 23 of the "NYISO 2004 State of the Market Report" <www.nyiso.com>

The important question is why have investors delayed the construction of new generating capacity in NYC given the high level of payments being made in the capacity auction. A plausible explanation is that the earnings from the capacity auction are risky and do not provide the financial security needed to build a new project. In other words, high average payments in a capacity auction are not equivalent to making the same payments through a multi-year Power Purchase Agreement (PPA).

In New York City, over a billion dollars has been paid each year through the capacity market to the owners of existing generating capacity. In spite of this major expenditure, the financial incentives have not been high enough to get investors to commit to building new generating capacity. The main accomplishment of these extra payments has been to increase the market value of the existing capacity. There is no obligation placed on generators in the NYISO capacity market to build new generating capacity when and where it is needed. The basic mistake made by regulators in New York State was to use one policy instrument to treat two very different policy objectives, namely 1) meeting the short-run objective of ensuring there is enough installed capacity available to maintain operating reliability, and 2) meeting the long-run objective of ensuring there is enough new investment to maintain generation adequacy. The financial needs of generators are very different for 1) installed Peaking units, 2) installed Baseload units, and 3) new generating capacity. For the first two types of capacity, financial arrangements already exist for the capital costs of past investments. For new capacity, new financial arrangements must be established, and typically, potential investors need to have a credible source of future earnings to secure financing.

C.2. The Forward Capacity Market

Recently, a new form of Forward Capacity Market (FCM) has been proposed for New England.[5] The design of the FCM addresses two of the major problems with the capacity market in New York State. First, the ISO determines how much generating capacity will be purchased three years ahead to maintain generation adequacy. This makes it feasible for investors to participate in the FCM before new capacity is built. Second, restrictions are placed on incumbent firms in the FCM that limit their ability to withhold capacity and to submit high offer prices. By discriminating between new and existing capacity in this way, the type of exploitation of market power by large firms in the capacity market in NYC is likely to be severely limited in the FCM.

The current situation in PJM is similar to the situation in New England, regulators in PJM are not satisfied with the performance of the existing capacity market and have proposed an alternative design that has not yet been implemented. This new design is called the Reliability Pricing Model (RPM)[6]. The RPM is based on a demand curve similar to the one in Figure 2, but, like the design of the FCM, the capacity is purchased four years in advance. However, the responses to a shortfall of capacity are quite different in the RPM and the FCM. When insufficient capacity is offered into the FCM, the ISO cancels the auction and establishes bilateral contracts to build the additional capacity. In contrast, if insufficient capacity is offered into the RPM, the market price of capacity will be higher and less capacity will be purchased than the “right” amount needed to maintain reliability.[7] This higher price may provide the financial incentive needed to build new capacity in the future, but there is still no guarantee that this will actually happen. The strategy followed in the FCM is more direct and is designed to get the right amount of capacity installed in time to maintain reliability standards.

There are other objectives that underlie the design of the RPM. Market prices in the existing capacity market in PJM have been very volatile and have exhibited a boom-and-bust characteristic. This has made earnings from the capacity market very risky for generators. An important objective of the RPM is to stabilize earnings, and this may well occur. However, a key feature of the FCM is missing from the RPM, and this is the ability for investors in new capacity

[5] Affidavit of Peter Cramton, Appendix to ER03-563-000, 030, 055, <http://www.iso-ne.com/markets/othrmkts_data/fcm/filings/index.html>.

[6] Statements of Audrey A. Zibelman and Andrew Ott for a Technical Conference on the Reliability Pricing Model, Filed by PJM Interconnection, LLC for FERC Docket Nos. ER05-1410-000 and, EL05-148-000 on February 3, 2006.

[7] The minimum reserve margin for generating capacity needed to meet a given reliability standard.

to lock-in a price for up to five years in the FCM. Having a firm contract for five years is a major step towards having the type of financial security needed to raise capital for building new capacity. Holding a standard form of Power Purchase Agreement (PPA) would provide even more financial security.

The basic structure of the FCM is that the ISO determines how much generating capacity will be needed three years ahead to maintain generation adequacy. The ISO purchases this amount of capacity for one year using a descending-clock auction[8] with the same market price paid to all installed and new capacity. This price is a commitment, and generating units accepted in the auction are paid this price three years later if specified standards of performance are met (e.g. being available when needed). The costs of these purchases are covered by the ISO and then allocated to Load Serving Entities (LSEs) in proportion to their actual loads. There are a number of potential advantages of the FCM design compared to the LICAP design. The most important of these are as follows:

1) The ISO determines the amount of capacity purchased and backs this purchase. This responsibility is not given to LSEs, and therefore, the problems of uncertainty about how much capacity will be purchased and the limited credit-worthiness of LSEs are eliminated.

2) The capacity purchased is for availability three-years-ahead, and furthermore, investors in new capacity can lock-in this price for up to five years. Installed generating units can only sell capacity for one year at a time. This rule effectively discriminates between installed capacity and new capacity. Potential investors can establish a secure price for capacity up to eight years ahead. If a similar forward contract for fuel has been secured, an investor would hold contracts that are similar to a PPA for up to five years. However, these contracts do not cover the remaining uncertainty about earnings in the spot market for electricity[9].

3) Using a descending-clock auction that starts at a high price implies that the ISO knows in advance whether or not there is sufficient capacity offered into the auction to cover the capacity requirement for generation adequacy. The FCM has explicit rules about starting the auction, and if there is not enough capacity offered to meet this minimum requirement, the auction is cancelled. In this situation, there is a formula for paying all of the capacity that was offered into the auction, and more importantly, the ISO can issue a Request For Proposal (RFP) to build any additional capacity that is needed. The FCM design puts the main emphasis on ensuring that the physical quantity of capacity is sufficient to meet generation adequacy three years ahead. In contrast, the LICAP design only determines the actual amount of capacity purchased one month ahead.

4) Restrictions are placed on incumbent firms in the FCM that limit their ability to withhold capacity and submit high offer prices. The allowed ranges of offers are defined in terms of a specified Cost Of New Entry (CONE), and the offers for new capacity can be up to

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[8] This type of auction starts at a high price specified by the ISO. All suppliers owning installed generating units and investors considering the construction of new generating units register the amount of capacity that they would supply at the initial price. Assuming this amount is greater than the amount specified by the ISO, the price (clock) is lowered until some generating units are withdrawn from the auction. The final market price is set when the amount of capacity remaining is equal to the amount needed.

[9] This remaining financial uncertainty is likely to be more of an issue for a new baseload unit than a peaking unit because the FCM is designed to cover the full capital cost of a peaking unit but this will be only part of the capital cost of a baseload unit. A baseload unit is expected to earn enough net-revenue in the spot market to cover the rest of its capital cost. In addition, anyone building a new baseload unit would probably want to have a PPA for at least ten years. Hence, the FCM is more likely to accommodate the construction of new peaking units than baseload units, and there is still a substantial amount of financial risk associated with building a new baseload unit without some form of PPA.

2xCONE but the offers for existing capacity must be below 0.8xCONE[10]. By discriminating between new and existing capacity in this way, the type of exploitation of market power by large incumbent firms in the LICAP market in NYC is likely to be severely limited in the FCM. New generating units can submit higher offer prices for capacity, and if this new capacity is needed, the higher price is paid for all capacity. However, the existing generating units cannot set such a high price. There are modifications to this restriction on offers for units that are going to be retired (de-listed), but the general objective of limiting the market power of incumbent firms is an explicit feature of the FCM.

5) Although the market price of capacity is set three years ahead in the FCM, the actual payment to generators occurs in the actual year of delivery. This payment is only made if a generating unit meets explicit standards of availability. In this way, the FCM addresses both the long-run criterion of generating adequacy three years ahead, and the short-run criterion of operating reliability for that delivery year. Payments are reduced by poor performance, and this type of regulatory mechanism has a lot in common to the rationale for using Performance Based Regulation (PBR).

6) A final and unusual feature of the FCM is that generating units accepted in the auction held three years earlier are not allowed to get “excess” earnings from high prices in the spot market for electricity. The combined earnings from the FCM and the spot market are limited in the following way. The ISO sets a price cap of $150/MWh, for example, in the spot market, and all revenues paid to suppliers above this cap are offset by equivalent reductions of the capacity payments. In this respect, the FCM provides a minimum level of earnings, and excess earnings above the price cap are, in effect, returned to the ISO. This mechanism is also similar to the rationale for using a PBR[11]. An important implication of this price cap in the spot market is that it will reduce the incentives for speculating, and therefore, will make the spot prices more competitive. By making the spot prices more competitive, the level of income obtained from the FCM will be more critical for securing the financial viability of new generating units.

The overall conclusion is that the design of the FCM has addressed most of the obvious deficiencies of the LICAP market in New York State. Although there is no evidence available at the time to determine how well the FCM will perform in practice, it seems likely that the FCM will be able to identify possible shortfalls of generating capacity far enough in advance to get new peaking capacity built in time. This is not possible for the LICAP market because clearing only one month ahead effectively limits the range of options for meeting a shortfall to shedding load. Given the importance of maintaining generation adequacy for reliability, it is unrealistic to rely on the LICAP market. The responsibility for this important task must be taken by some other regulatory mechanism. The LICAP market is effectively a way to provide additional income for incumbent firms. Decisions to build new generating capacity may be influenced by expectations of future earnings in the LICAP market, but the existence of this market does not represent a reliable way to maintain generation adequacy. Most of the money spent in the LICAP market does nothing more than inflate the market value of existing generating units.

[10] Withholding existing capacity from the FCM is also discouraged by requiring generators to present a justification for withholding a generating unit that must be authenticated by the ISO.
[11] A typical example of PBR would provide a floor on the earnings of suppliers in return for some form of profit sharing between suppliers and the public.

C.3. Results

A series of economic experiments were conducted in spring 2007 to test the performance of the FCM using graduate students at Cornell University. The students represented three incumbent firms and software agents represented potential new entrants. The experiments consisted of two tests, Test 1 and Test 2. In Test 1, there was only one type of generating capacity. Incumbent firms owned some installed capacity and could build new capacity, and new entrants (firms) could also build new capacity. The economic challenge for the incumbent firms (students) was 1) could they maintain market share by keeping new entrants out of the market, and 2) could they build new capacity, and get a high price for all capacity sold, even though new capacity was not really needed to maintain generation adequacy.

In Test 2, there were two types of generating capacity, peaking and baseload. The basic economic conditions corresponded to a situation with high prices for natural gas, and therefore, high costs for peaking units. Under these conditions, the economically efficient choice for building new capacity when it was needed was to build baseload units, because the higher earnings in the spot market were more than enough to cover the higher capital costs. However, the mix of installed generating capacity in the spot market affected the earnings of baseload units, and adding new baseload units lowered the earnings of the installed baseload capacity in the spot market.

Test 2 consisted of two sub tests, Test 2-A and Test 2-B. In Test 2-A, there were barriers to entry and new entrants could only build peaking units. The incumbents could build either new peaking units or new baseload units. In Test 2-B, new entrants and incumbents could build baseload and/or peaking units. The additional economic challenge for the incumbents was to decide what type of capacity to build. In Test 2-A, the incumbents would earn higher total profits by ensuring that only new peaking units were built even though the profits for a new unit would be higher for a baseload unit. In Test 2-B, although the basic economic logic was the same as Test 2-A for the incumbents, new entrants were more aggressive and were willing to build new baseload units at a low price if the combined profits for baseload units from the spot and capacity markets were high.

In both Test 1 and Test 2, the capacity market was run for sessions consisting of ten trading periods. The demand (load) was constant for the first three periods and then grew at a rate of 10 units per period from period four to period eight. Demand was constant for the last two periods. The initial amount of installed capacity was sufficient to cover the demand for the first four periods, and therefore, the amount of new capacity needed to maintain generation adequacy over the ten periods was only 40 units.

In Test 1 when there was only one type of generating capacity, the incumbent firms were successful in maintaining market share and keeping out new entrants. This was accomplished by submitting offers in the capacity market that were lower than the true cost of building a new unit and offsetting this loss with the corresponding higher earnings in the spot market from installed capacity. In addition, the incumbent firms created artificial scarcity during flat demand periods by using legal ways to withhold capacity (i.e. exporting and repowering existing units), and therefore, made it possible for a new unit to set a high price.

In Test 2-A when there were two types of generating capacity but new entrants could not build baseload units, the incumbent firms had no incentive to build new baseload units even though they were more profitable than a new peaking unit. Instead, the incumbent firms used their profits to protect earnings from their installed baseload units by building new peaking units.

In Test 2-B when new entrants could build both baseload and peaking units, it was more difficult for the incumbent firms to protect their high profits from installed baseload units in the spot market, and as a result, they built some new baseload units as well as new peaking units to prevent new entrants making very low offers to build new baseload units and bringing down the price of all capacity.

Figure 4 illustrates the results for Tests 1, 2-A and 2-B for selected groups of students who were able to manipulate the market successfully. In all three cases, the solid black line represents the economically efficient cumulative additions to generating capacity needed to maintain generation adequacy, and in all three cases, the actual additions were higher than the efficient amounts. In particular, the students were able to withhold existing capacity using legal means to create artificial scarcity in the early periods so that new capacity had to be purchased. By doing this, the price paid for all capacity was higher than it would be if installed capacity had set the price.

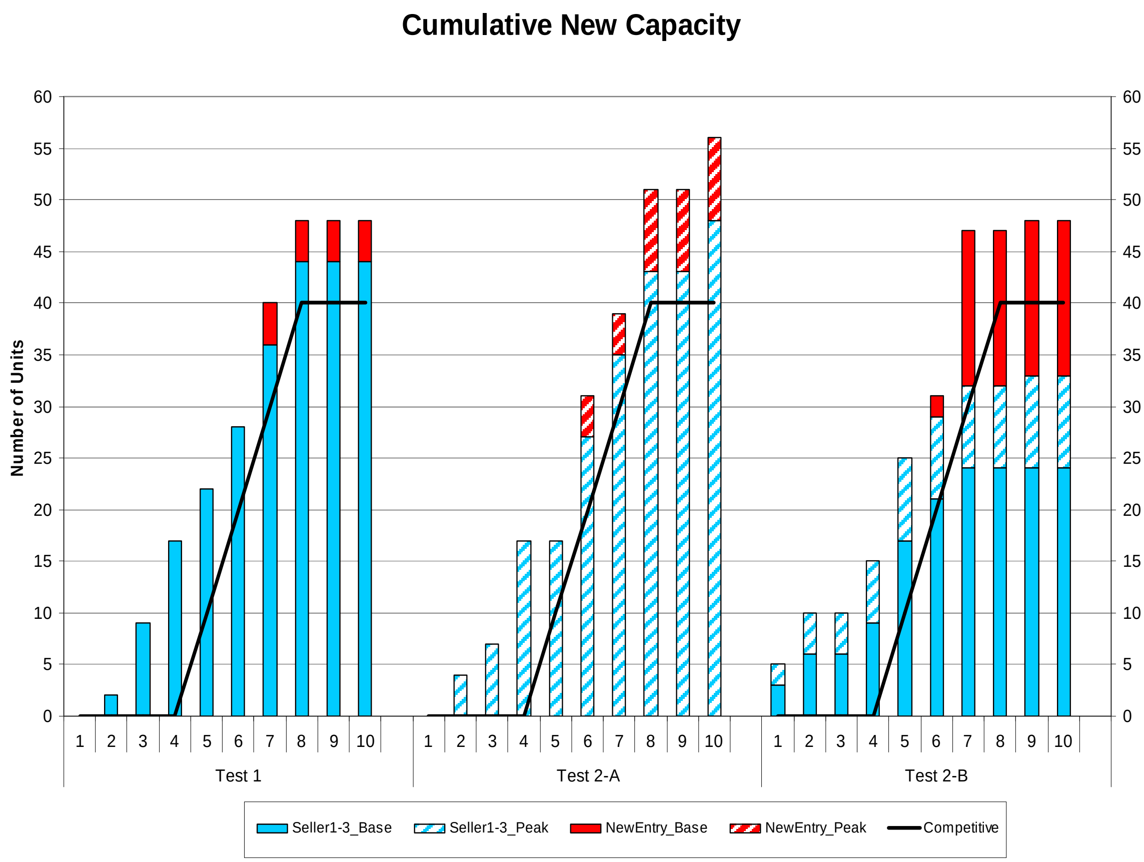


Figure C.4. The Cumulative New Capacity plots for FCM Test 1, Test 2-A and Test 2-B (selected groups)

Figure 4 also shows how many new units were built by incumbents (blue) and by new entrants (red). For Test 1, incumbents built more than the 40 units needed in an efficient market and new entrants built less than 5 units. For Test 2, the results were similar. However, the important additional result is that only new peaking units (striped) were built even though a new baseload unit (solid) would be more profitable. These students realized that building new baseload units would reduce earnings from their installed baseload units in the spot market. In Test 2-B, both incumbents and new entrants built new baseload units. The incumbents also built some peaking units, but it was much harder for them to protect the profitability of their installed baseload units in the way that they had in Test 2-A.

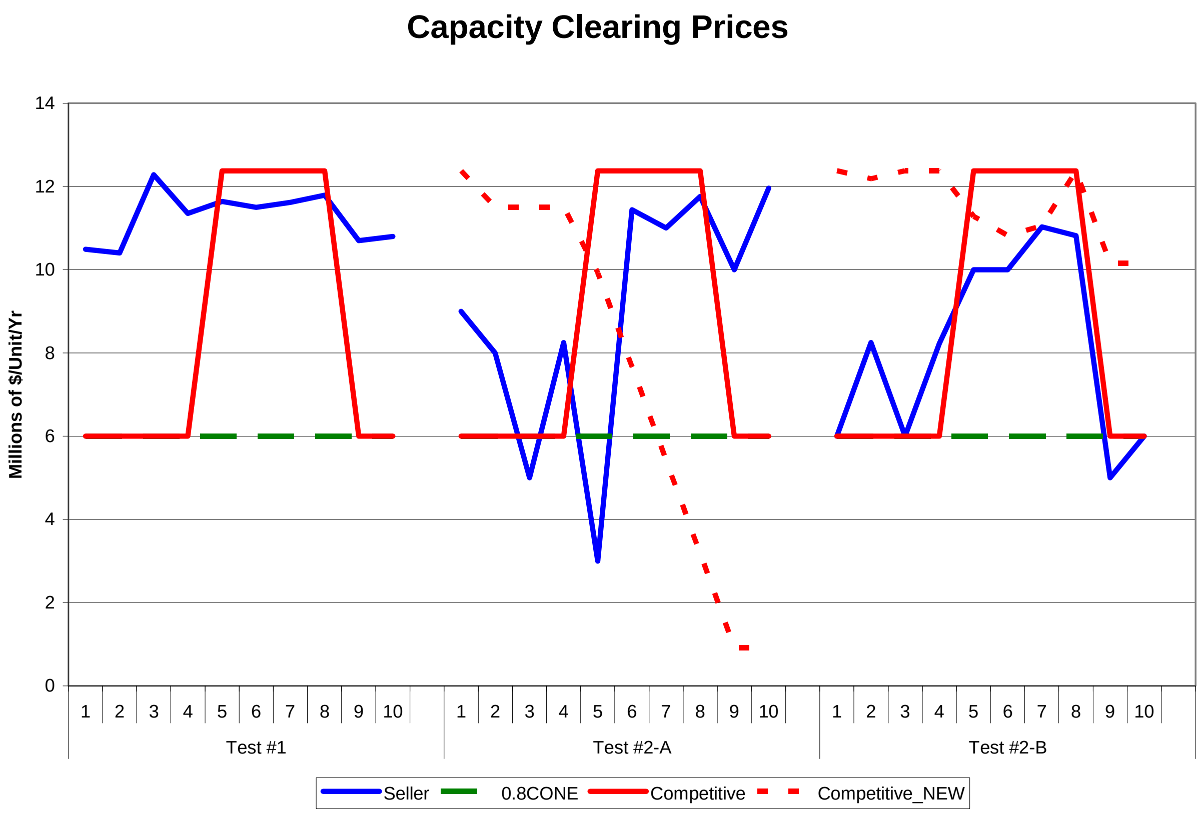


Figure C.5. An Example of the Prices for Capacity in Test 1, Test 2-A and Test 2-B (selected Group)

Figure 5 shows the capacity clearing prices for the three cases. The green dotted line is the maximum allowed offer for installed capacity. The competitive price (red) is equal to this maximum offer when no new capacity is needed, and is equal to the actual cost of new entry when new capacity is needed. In Test 1, the incumbents firms were able to maintain the price well above the maximum offer for installed capacity (by legal withholding so that a new unit was able to set the price), and in addition, they undercut the cost of a new entrant when new units were needed to meet growth in demand.

In Tests 2-A and 2-B, the solid red line is the competitive price assuming that only new peaking capacity can be built. The red dotted line is the entry price for a new baseload that includes earnings in the spot market. In Test 2-A when new entrants could not build baseload units, the incumbents built less profitable peaking units to increase their earnings from their installed baseload units. As a result, the true entry price for a new baseload unit fell almost to zero. Under these circumstances with barriers on the construction of baseload capacity by new entrants, the market for the incumbents is not incentive compatible. It does not pay the incumbents to use their high profits from installed baseload capacity to build new baseload capacity even though a new baseload unit would be profitable on its own. As a result, the incumbents built less profitable peaking capacity.

The results were different in Test 2-B when new entrants could build new baseload units. The incumbents had to accept modest profits from their installed baseload units to avoid having new entrants bring the market price down by making very low offers to build new baseload units. Consequently, the entry price for a baseload unit (red dotted line) did not drop the same way that it did in Test 2-A.

Table C.1. New Units Built by Incumbents (Se) and New Entrants (Ne) in Test 1 (Five 10 period Sessions conducted by five different Groups of students, G1-5)

	Test1#1		Test1#2		Test1#3		Test#4		Test1#5		Test1(Av)	
	Se	Ne	Se	Ne	Se	Ne	Se	Ne	Se	Ne	Se	Ne
G1	35	10	24	24	37	10	27	14	32	10	31	14
G2	28	20	35	10	47	0	44	4	42	2	39	7
G3	30	16	44	4	41	6	48	0	51	4	43	6
G4	12	38	26	20	34	14	34	6	41	2	29	16
G5	50	6	48	0	41	6	32	18	44	4	43	7
AV	31	18	35	12	40	7	37	8	42	4	37	10

Table 1 summarizes the results of Test 1 for all five groups of students and all five sessions in terms of the number of new units built by incumbents (Se) and by new entrants (Ne). In 24 of the 25 sessions, the incumbents built more units that the new entrants, and in 3 sessions, new entrants did not build any new units.

Table C.2. New Units Built by Incumbents (Sel1-3) and New Entrants (NeEn) in Test 2-A

	Test2-A_#1			Test2-A_#2			Test2-A (AV)		
	Seller1-3		NeEn	Seller1-3		NeEn	Seller1-3		NeEn
	Ba	Pe	Pe	Ba	Pe	Pe	Ba	Pe	Pe
G1	32	18	0	29	19	0	31	19	0
G2	36	19	0	16	27	0	26	23	0
G3	20	9	22	34	8	10	27	9	16
G4	0	48	8	0	40	14	0	44	0
AV	22	24	8	20	24	6	21	24	4

(Baseload, Ba and Peaking, Pe. Two 10 period Sessions conducted by four different Groups of students, G1-4)

Table C.3. New Units Built by Incumbents (Sel1-3) and New Entrants (NeEn) in Test 2-B

	Test2-B_#3				Test2-B_#4				Test2-B (AV)			
	Seller1-3		NeEn		Seller1-3		NeEn		Seller1-3		NeEn	
	Ba	Pe	Ba	Pe	Ba	Pe	Ba	Pe	Ba	Pe	Ba	Pe
G1	36	12	2	0	32	19	2	0	34	16	2	0
G2	30	16	4	0	5	26	18	0	18	21	11	0
G3	16	18	18	0	24	9	15	0	20	14	17	0
G4	22	34	19	0	29	23	6	0	26	29	13	0
AV	26	20	11	0	23	19	10	0	24	20	11	0

(Baseload, Ba and Peaking, Pe. Two 10 period Sessions conducted by four different Groups of students, G1-4)

Tables 2 and 3 summarize the results for Tests 2-A and 2-B. In Test 2-A, only group G4 truly understood that the most profitable strategy was to add new peaking capacity to increase earnings from their installed baseload units. However, this group lost some money by undercutting the cost of building new peaking units. They would have earned even higher profits by allowing new entrants to build the new peaking capacity.

In Test 2-B, the incumbent firms had to deal with two important issues at the same time, namely, 1) maintaining market share by not allowing new entrants to build profitable baseload capacity, and 2) trying to keep the earnings of their installed baseload units from the spot market as high as possible. All four groups realized that they should build some new baseload units as well as peaking units. However, the incumbents found it much harder to keep new entrants out of the market and new entrants were able to build some new baseload units in all 8 sessions. On average, the total number of new units built by all participants was higher in Test 2-B (55) than in Test 2-A (49) and Test 1 (47). In all three cases, only 40 units would be needed in a competitive market.

C.4. Conclusions

The overall conclusion about the performance of deregulated markets for electricity in New York, New England and PJM is that regulators have adopted procedures that make the financial incentives in the wholesale market insufficient to get investors to build new Peaking units when they are needed. In response to this problem, additional sources of income for all generators have been established and the primary source of income is to use some form of capacity market. Most of the evidence about the performance of a capacity market comes from New York State because this market has been operating since 2003. The current performance of this market has been disappointing. First, it has still not overcome the problem of delays in the construction of new generating units in NYC. This is true in spite of making payments of over $1billion/year to incumbent firms in NYC. Second, the largest firms have been able to increase the market price of capacity and increase their earnings by exploiting market power in this capacity market.

Partly in response to the ongoing problems with the performance of the NYISO market, regulators have proposed new market designs for New England and PJM that have not yet been implemented. Even though these two designs are quite different from each other, they share a common feature of purchasing capacity three and four years ahead, instead of just one month ahead as is done in the existing capacity market in New York. This change in design makes it feasible for potential investors in a new generating unit to participate in the capacity market before the unit is built, and to determine the capacity price for this unit when they commit to bringing it on-line. Hence, it is likely that these new capacity markets will be more effective than the NYISO market in getting new generating units committed in time to maintain generation adequacy. It remains to be seen how expensive these new markets will be for customers. The current situation in New York is that the capacity market is very expensive and there is still a lot of uncertainty about whether new capacity will be built when it is needed.

A series of economic experiments were conducted to test the performance of a Forward Capacity Market (FCM) using graduate students at Cornell University to represent incumbent firms and software agents to represent potential new entrants. In the first test, there was only one type of generating capacity in the market. The incumbent firms were successful in 1) maintaining market share and keeping out new entrants by undercutting the cost of building a new unit (gains in wholesale market earnings were more than enough to offset the loss in building a new unit), and 2) creating artificial scarcity using legal ways to withhold capacity and therefore allow a new unit to set a high price (by repowering existing units, for example).

In the second test, there were two types of generating capacity, peaking and baseload. The earnings of baseload units in the wholesale market depended on the amount of time that peaking units set the price. Consequently, the earnings of an installed baseload unit increase when higher loads are met by building new peaking units. Even though the profits are very high for an installed baseload unit, the results show that the incumbent firms have no incentive to build new baseload units if new entrants can only build new peaking units. The incumbent firms will not reinvest their profits in new capacity unless potential new firms can build new baseload units, and therefore, make low offers to build new baseload units that take into account the high earnings in the spot market. Hence, institutional barriers to entry associated with the safety of nuclear plants and environmental restrictions on emissions from coal plants, for example, may undermine the performance of the FCM. Under these circumstances, there is no economic incentive for owners to use profits from installed baseload units to expand baseload capacity even though it would be the socially efficient to do so.

Appendix D.
Proposed Instructions for Participants in Physical/ Financial Forward Markets Sequenced with Investment and Planning (of Revised Transmission Network)

Ray Zimmerman and Corey Lang

D.1. Buyer Instructions

Introduction
This is an educational training exercise designed for students in CEE 594/ECON 494. The exercise relates to concepts covered in class on markets and market design, competition, and investment. Participants in this exercise may play the role of 1) a firm who produces electricity, 2) a consumer that buys electricity, or 3) a trader that can buy or sell securities in a forward market. The decisions you make during the exercise will determine your earnings, and you will receive points towards your grade in the course in proportion of your total earnings over the course of the semester. You will maximize the points you receive by maximizing the earnings you obtain. Please do not communicate with any of the other class members outside of your group about this exercise until it has been completed.

General Information
You are a buyer. There are five other active buyers in the market. In addition, there are 13 other inactive buyers, meaning they are not played by participants, but by the computer. There are also six sellers who produce electricity. Each of the buyers, active and inactive, and sellers are located at specific points on the electric grid. In addition, both buyers and sellers can participate in a forward market by buying and selling electricity futures/derivatives/securities. There will also be additional agents, called traders, participating in the forward market who are neither buyers nor sellers.

Each period will consist of three subperiods: capacity investment, forward market, and spot market. During the capacity investment subperiod, sellers can increase the capacity of their plant by constructing additional capacity or decrease their capacity by not maintaining old units. During the forward market subperiod, sellers and buyers are able to buy and/or sell electricity futures/derivatives/securities that will be fulfilled in the spot market. During the spot market subperiod, sellers offer their physical generation to be sold and buyers place bids on the generation. You will receive earnings based on difference between your revenue from sales and your costs from electricity purchases, as well as earnings in the forward market.

The Transmission Network
In this experiment, the generators and the loads are connected by a transmission network which must be operated at all times in a manner consistent with the laws of physics governing the flow of electricity. A small percentage of the energy produced is dissipated by transmission losses, and the system operator must produce more than the total load. For a given pattern of load, the exact amount generated is dependent on where the power is produced. In addition, the operation

of the network is constrained by the physical limitations of the equipment used to generate and transmit the power. This implies that there are limits to the amount of power that can be transmitted from one part of the network to another. Congestion, which occurs when these limits are reached, can sometimes make it impossible for the system operator to utilize inexpensive generation, forcing the system operator to purchase more expensive generation from a different location.

This transmission network consists of two regions. Four of the sellers have their generating capacity located at buses in Region A, while the other two sellers have their generating capacity located at buses in Region B. *[might change due to ownership patterns]*. We will now detail the three subperiods that will occur in each round, highlighting the purpose of the subperiod and the specific decisions that must be made. Though buyers do not participate in the capacity investment subperiod, it may be useful to learn about it in order to inform your strategy.

Capacity Investment Subperiod
Buyers do not participate in the Capacity Investment Subperiod. During this period, sellers are able to invest or disinvest in their generating units to change their capacity. Each of the sellers has an initial generating capacity of X units. Investing and disinvesting in capacity both incur and one time per unit cost of $X and $X respectively. Sellers are limited in their disinvesting options – you can only disinvest X% of your current capacity. There is no limit to how much they can invest. There is also a per unit capacity cost which must be paid for each unit of capacity a seller has after the capacity subperiod is finished. Sellers have time limit of X minutes to make their decisions, afterwards the next subperiod will begin.

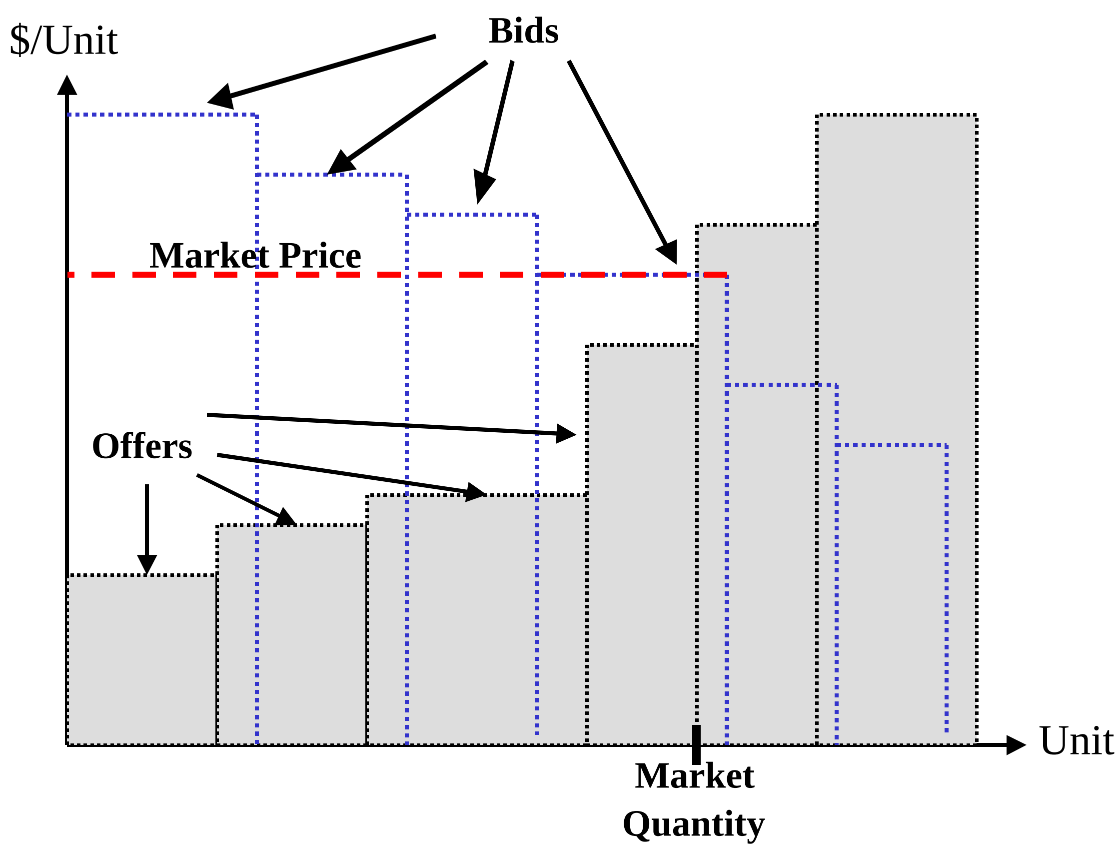
Forward Market Subperiod
Due to the physical structure of the electric grid, there are two distinct regions and these regions may have different spot market prices. Thus, each region has its own forward market. Both sellers and buyers, as well as the additional agents, are able to participate in each of the two forward markets. Each forward market is a purely financial market and the transactions enacted in the forward market do not influence the dispatch or prices set in the spot market. Each player has the ability to submit two offers, two bids, or one offer and one bid into each of the two regions (for a combined total of four offers/bids). The forward market is only half of the transaction though; the rest is fulfilled after the spot market prices have been set. Once the nodal prices in the spot market have been determined, a load-weighted average price is created for each region based on the spot market nodal prices. This load-weighted average price is used to fulfill the transactions made in the forward market. If you buy one or more units in the forward market, then your revenue would be (spot price – forward price)*units bought. Similarly, if you sell in the forward market, your revenue would be (forward price – spot price)*units sold.

For example, suppose you bid to buy two units at $10 in the forward market for region A. The region A forward market clears at $8, so you pay $8 per security for a total of $16. After the spot market subperiod, the load-weighted average price for region A is $11 per unit. You would earn a net forward market revenue of ($11-$8)*2=$6.

A note on strategy. There are a couple of different ways you could use your two offers/bids in each region. If you only want to buy securities, then you could place two bids for different price/quantity pairs. This would allow you to buy a small quantity if the price was high but a larger quantity if the price was low. Vice versa, you could use the same strategy to two offers if you only wanted to sell. Alternatively, you could enter one offer and one bid, with the bid being less than the offer. This would allow you to buy if the price was low and sell if the price was high.

A Uniform Price Auction is utilized for the forward market and the Last Accepted Offer*** is the market price.

We will determine the market-clearing price in the forward market by intersecting the bids with the offers. Every seller will be paid the same market-clearing price, and every buyer will pay the same market-clearing price. The market price will be the last accepted offer. See diagram below. *(perhaps an average of the last accepted offer and the last accepted bid should be used for the market clearing price. No reason for asymmetry when participants are on both sides of the market).* You must indicate whether you wish to buy or sell for each offer/bid in each region and then enter your corresponding price quantity offers/bids.



Also displayed is a forecast of demand for each of the two regions. This forecast provides a useful estimate of actual demand, but can be wrong by as much as X%. The forecasted demand will be updated in each subperiod, but actual demand will not be revealed until after the conclusion of the spot market subperiod. The following information is also found in the table/graph showing the demand forecast. These things will be explained later as well.

1. The **forecasted and actual load** in units will typically vary from period to period (the yellow background indicates that the forecasts may change).
2. The **installed capacity** in units gives the total of the maximum generating capacity of all suppliers in the market for each region.

(Pending on the order of the Capacity Investment subperiod and the forward market subperiod, see treatment B vs. treatment C, this forecast can either be more or less accurate than the forecast seen in the capacity investment subperiod. Whichever period occurs first has the less accurate forecast.)

When you have entered your bids/offers, click the ‘Submit Forward Market Decision’ button. You will only have X minutes to enter your decision. If you fail to do so in this time, PowerWeb will automatically advance you to the next screen with no offers nor bids in the forward market. Once you hit the submit button, your screen will display a waiting icon, indicating that other participants in your market have not submitted their forward market decisions yet. Once everyone has submitted, your screen will automatically advance to the next subperiod.

Spot Market Subperiod

In the spot market, sellers submit offers to sell electricity and buyers submit bids to buy electricity. Unlike the two forward markets, there is only one spot market. Only sellers are able to submit offers in the spot market. The six active buyers make bids into the spot market and these are combined with the bids of the inactive buyers to complete the demand side of the market.

The Spot Market is based on the physical attributes of the electrical network. After all the offers and bids have been entered, the system operator will choose to accept the least expensive offers which are able to meet the load while satisfying all of the constraints of the transmission system. The prices paid to each supplier are nodal prices, specific to their location. Each nodal price is equal to the marginal cost to the system operator of meeting an additional unit of demand at the corresponding node.

In a network without congestion or losses, a Uniform Price Auction determines the least-cost pattern of generation by paying the Last Accepted Offer to all accepted offers. In this type of auction, the system operator ranks the supplier’s offers from the least expensive to the most expensive, and accepts offers in order from the lowest to the highest offer price until sufficient capacity is purchased to meet the load. The system operator pays all purchased capacity the same (uniform) price, and this price is equal to the offer for the most expensive capacity purchased. However, as losses and congestion increase, the system operator is forced to accept offers out of order (some expensive units may be accepted while less expensive ones are rejected), and the prices at the different nodes vary and move away from a single uniform price. In summary, the quantity delivered and price at a given node depends not only on bids and offers, but on the structure of the network.

In the spot market,

(1) You may submit two price/quantity bids. Note, there is no minimum allowable price. However, if you submit a price that is lower than the supply curve, those units will not be bought.

(2) You will never pay more than your bid price for the capacity you buy.

Once you have entered your price/quantity pairs, click the 'Submit Spot Market Bids' button. You will only have X minutes to enter your decision. If you fail to do so in this time, PowerWeb will automatically enter a bid to buy the maximum quantity on your demand curve at an infinite price/enter bids from last period (what if in the first period). Note that even with the infinite price bid, you will only pay the market price. Once you hit the submit button, your screen may display a waiting icon, indicating that other participants in your market have not submitted their spot market decisions yet. Once everyone has submitted, your screen will automatically advance to the next subperiod.

All Results

After you have submitted your bids/offers, whether in the Forward Market Subperiod or the Sport Market Subperiod, PowerWeb will inform you to wait until all of the other suppliers have finished submitting their offers. The results will then be calculated by PowerWeb and presented to you on your Market History screens. You will have two market history screens open at all times, in addition to the screen on which you enter your bids/offers. One of these screens shows the market history for the two regions separately. The other screen shows your personal market history. Both of these screens will be open at all times and will be automatically updated by PowerWeb as new information becomes available, i.e. as investment decisions are made and as markets clear. You are able to toggle between these two screens and your main input screen.

Treatment A

For this exercise, there is no forward market. The sequence of events for this exercise is as follows. First, the six sellers must decide how much capacity to add to their generating units. Next, each buyers and sellers submit quantity and price bids and offers, respectively, in the spot market. This sequence will be repeated until the exercise ends randomly after 20 periods.

Treatment B

For this exercise, there are six sellers, six active buyers, and X traders in the market. The sequence of events is as follows. The capacity investment subperiod occurs first. Second, the forward market. And third, the spot market. This sequence will be repeated until the exercise ends randomly after 20 periods.

Treatment C

For this exercise, there are six sellers, six active buyers, and X traders in the market. The sequence of events is as follows. First, the forward market. Second, the capacity investment subperiod. And third, the spot market. This sequence will be repeated until the exercise ends randomly after 20 periods.

D.2. Seller Instructions

Background
This is an educational training exercise designed for students in CEE 594/ECON 494. The exercise relates to concepts covered in class on markets and market design, competition, and investment. Participants in this exercise may play the role of 1) a firm who produces electricity, 2) a consumer that buys electricity, or 3) a trader that can buy or sell securities in a forward market. The decisions you make during the exercise will determine your earnings, and you will receive points towards your grade in the course in proportion of your total earnings over the course of the semester. You will maximize the points you receive by maximizing the earnings you obtain. Please do not communicate with any of the other class members outside of your group about this exercise until it has been completed.

Introduction
You are a seller that owns one generating unit. There are five other sellers with generating capacity similar to your own. Each of the generating units owned by you and the other sellers are located at particular locations on an electrical grid.

There are many consumers who need the electricity you produce for their daily use. In addition to the six sellers, there are 19 buyers who will buy electricity from the sellers. Six of these buyers are participants like you and the rest of them are played by the computer; we will call them active buyers and inactive buyers, respectively. Just like the sellers, the consumers are located at specific points on the electrical grid. In addition, both buyers and sellers can participate in a forward market by buying and selling electricity futures/derivatives/securities. There will also be additional agents, called traders, participating in the forward market who are neither buyers nor sellers.

Each period will consist of three subperiods: capacity investment, forward market, and spot market. During the capacity investment subperiod, sellers can increase the capacity of their plant by constructing additional capacity or decrease their capacity by not maintaining old units. During the forward market subperiod, sellers and buyers are able to buy and/or sell electricity futures/derivatives/securities that will be fulfilled in the spot market. During the spot market subperiod, sellers offer their physical generation to be sold and buyers place bids on the generation.

You will receive earnings based on difference between your revenue from sales and your costs from electricity production, as well as earnings in the forward market.

The Transmission Network
In this experiment, the generators and the loads are connected by a transmission network which must be operated at all times in a manner consistent with the laws of physics governing the flow of electricity. A small percentage of the energy produced is dissipated by transmission losses, and the system operator must produce more than the total load. For a given pattern of load, the exact amount generated is dependent on where the power is produced. In addition, the operation of the network is constrained by the physical limitations of the equipment used to generate and

transmit the power. This implies that there are limits to the amount of power that can be transmitted from one part of the network to another. Congestion, which occurs when these limits are reached, can sometimes make it impossible for the system operator to utilize inexpensive generation, forcing the system operator to purchase more expensive generation from a different location.

This transmission network consists of two regions. Four of the sellers have their generating capacity located at buses in Region A, while the other two sellers have their generating capacity located at buses in Region B. *[might change due to ownership patterns]*

We will now detail the three subperiods that will occur in each round, highlighting the purpose of the subperiod and the specific decisions that must be made.

Capacity Investment Subperiod

Each of the sellers' generating units has an initial capacity of X units. During this subperiod, sellers are able to invest or disinvest in their generating units to change their capacity. Investing and disinvesting in capacity both incur and one time per unit cost of $X and $X respectively. You are limited in you disinvesting options – you can only disinvest X% of your current capacity. There is no limit to how much you can invest. There is a per unit capacity cost which must be paid for each unit of capacity a seller has after the capacity subperiod is finished. The following screen will be displayed during this subperiod. For each generator, you must decide if you want to invest or disinvest in capacity and by how much. Once you have entered your investment decisions, click the 'Submit Investment Decision' button. You will only have X minutes to enter your decision. If you fail to do so in this time, you will automatically be advanced to the next screen with no change is your level of capacity. Once you hit the submit button, your screen may display a waiting icon, indicating that other participants in your market have not submitted their investment decisions yet. Once everyone has submitted, your screen will automatically advance to the next subperiod.

Also displayed on this screen is a forecast of demand for each of the two regions. This forecast provides a useful estimate of actual demand, but can be wrong by as much as X%. The forecasted demand will be updated in each subperiod, but actual demand will not be revealed until after the conclusion of the spot market subperiod. The following information is also found in the table/graph showing the demand forecast. These things will be explained later as well.

1. The **forecasted and actual load** will typically vary from period to period (the yellow background indicates that the forecasts may change).
2. The **installed capacity** gives the total of the maximum generating capacity of all suppliers in the market for each region.

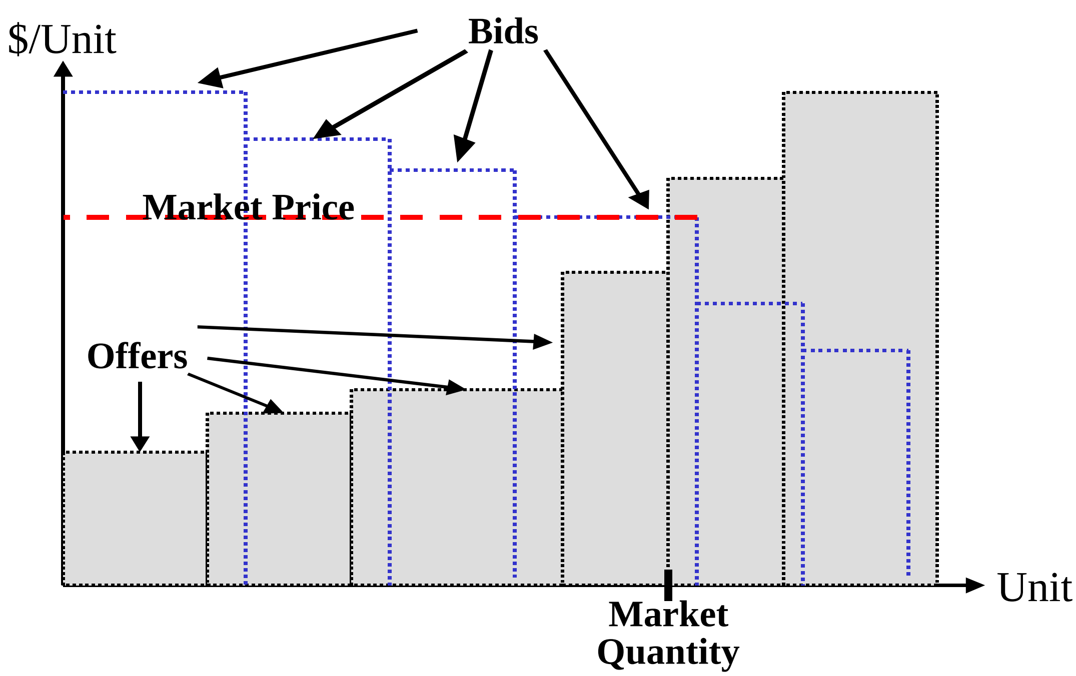
Forward Market Subperiod

Due to the physical structure of the electric grid, there are two distinct regions and these regions may have different spot market prices. Thus, each region has its own forward market. Both sellers and buyers, as well as the additional agents, are able to participate in each of the two forward markets. Each forward market is a purely financial market and the transactions enacted in the forward market do not influence the dispatch or prices set in the spot market. Each player has the ability to submit two offers, two bids, or one offer and one bid into each of the two regions (for a combined total of four offers/bids). The forward market is only half of the transaction though; the rest is fulfilled after the spot market prices have been set. Once the nodal prices in the spot market have been determined, a load-weighted average price is created for each region based on the spot market nodal prices. This load-weighted average price is used to fulfill the transactions made in the forward market. If you buy one or more units in the forward market, then your revenue would be (spot price – forward price)*units bought. Similarly, if you sell in the forward market, your revenue would be (forward price – spot price)*units sold.

For example, suppose you bid to buy two units at $10 in the forward market for region A. The region A forward market clears at $8, so you pay $8 per security for a total of $16. After the spot market subperiod, the load-weighted average price for region A is $11 per unit. You would earn a net forward market revenue of ($11-$8)*2=$6.

A note on strategy. There are a couple of different ways you could use your two offers/bids in each region. If you only want to buy securities, then you could place two bids for different price/quantity pairs. This would allow you to buy a small quantity if the price was high but a larger quantity if the price was low. Vice versa, you could use the same strategy to two offers if you only wanted to sell. Alternatively, you could enter one offer and one bid, with the bid being less than the offer. This would allow you to buy if the price was low and sell if the price was high.

We will determine the market-clearing price in the forward market by intersecting the bids with the offers. Every seller will be paid the same market-clearing price, and every buyer will pay the same market-clearing price. The market price will be the last accepted offer. See diagram below. *(perhaps an average of the last accepted offer and the last accepted bid should be used for the market clearing price. No reason for asymmetry when participants are on both sides of the market.)*



You must indicate whether you wish to buy or sell for each offer/bid in each region and then enter your corresponding price quantity offers/bids. Also displayed on this screen is a forecast of demand for each of the two regions. This forecast provides a useful estimate of actual demand, but can be wrong by as much as X%. *(Pending on the order of the Capacity Investment subperiod and the forward market subperiod, see treatment B vs. treatment C, this forecast can either be more or less accurate than the forecast seen in the capacity investment subperiod. Whichever period occurs first has the less accurate forecast.)*

When you have entered your bids/offers, click the 'Submit Forward Market Decision' button. You will only have X minutes to enter your decision. If you fail to do so in this time, PowerWeb will automatically advance you to the next screen with no offers nor bids in the forward market. Once you hit the submit button, your screen will display a waiting icon, indicating that other participants in your market have not submitted their forward market decisions yet. Once everyone has submitted, your screen will automatically advance to the next subperiod.

Spot Market Subperiod
In the spot market, sellers submit offers to sell electricity and buyers submit bids to buy electricity. Unlike the two forward markets, there is only one spot market. Only sellers are able to submit offers in the spot market. The six active buyers make bids into the spot market and these are combined with the bids of the inactive buyers to complete the demand side of the market.

The Spot Market is based on the physical attributes of the electrical network. After all the offers and bids have been entered, the system operator will choose to accept the least expensive offers which are able to meet the load while satisfying all of the constraints of the transmission system. The prices paid to each supplier are nodal prices, specific to their location. Each nodal price is equal to the marginal cost to the system operator of meeting an additional unit of demand at the corresponding node.

In a network without congestion or losses, a Uniform Price Auction determines the least-cost pattern of generation by paying the Last Accepted Offer to all accepted offers. In this type of auction, the system operator ranks the supplier's offers from the least expensive to the most expensive, and accepts offers in order from the lowest to the highest offer price until sufficient capacity is purchased to meet the load. The system operator pays all purchased capacity the same (uniform) price, and this price is equal to the offer for the most expensive capacity purchased. However, as losses and congestion increase, the system operator is forced to accept offers out of order (some expensive units may be accepted while less expensive ones are rejected), and the prices at the different nodes vary and move away from a single uniform price. In summary, the quantity delivered and price at a given node depends not only on bids and offers, but on the structure of the network.

In the spot market,

(1) You may submit two price/quantity offers. Note, there is no price cap or maximum allowable price. However, if you submit a price that is higher that the demand curve,

those units will not be bought. If you choose to submit an offer on a block of capacity, you will have to pay a fixed **Standby Cost of $X/unit** for all capacity submitted regardless of whether you actually sell all of that capacity (The standby cost is a simple way to represent the opportunity cost of being available in the market. These costs could include postponing maintenance activities, not selling energy in another market and paying wages to part of the workforce.).

(2) You may choose to sell any proportion of a block of capacity between the **minimum capacity** and the **maximum capacity**, or to submit **zero** capacity.

(3) You will never receive less than your offer price for the capacity you sell. As a rule of thumb, if your offer price is less than the nodal price, you will sell all of the capacity offered. If your offer is greater than the nodal price, you will not sell any capacity from that block (it is possible to sell the minimum capacity even if the true nodal price is below your offer, but you will still be paid your actual offer for that capacity in this case).

(4) There is a **fixed cost** for each block of capacity that is automatically paid in every trading period (to cover the cost of financing capital investments). This is the same as the per period capacity cost from the capacity investment subperiod.

Once you have entered your price/quantity pairs, click the ‘Submit Spot Market Offers’ button. NOTE: submitting a blank offer for a generator with a non-zero capacity offer corresponds to submitting an offer price of zero --- be careful. You will only have X minutes to enter your decision. If you fail to do so in this time, PowerWeb will automatically offer all of your capacity at zero cost. This does not mean you will not get any revenue, you will still be paid the market price. Once you hit the submit button, your screen may display a waiting icon, indicating that other participants in your market have not submitted their spot market decisions yet. Once everyone has submitted, your screen will automatically advance to the next subperiod.

Also on this screen, there is a table that describes information for your generator that you control as a supplier. The rows for the **GENERATOR DATA** are:

1. The **location** of the unit.
2. The **minimum generation** in units for the generator to operate.
3. The **maximum capacity** in units of output from the generator.
4. The **variable cost** in $/unit (for fuel etc.) of generating electricity.
5. The **standby cost** in $/unit (the opportunity cost of being available for all capacity submitted to the auction).
6. The **fixed cost** in $/trading period (the cost of financing capital investments, such as interest payments on bonds).

All Results

After you have submitted your offers, whether in the Forward Market Subperiod or the Sport Market Subperiod, PowerWeb will inform you to wait until all of the other suppliers have finished submitting their offers. The results will then be calculated by PowerWeb and presented to you on your Market History screens. You will have two market history screens open at all times, in addition to the screen on which you enter your decisions and bids/offers. One of these screens shows the market history for the two regions separately. The other screen shows your personal market history. Both of these screens will be open at all times and will be automatically updated by PowerWeb as new information becomes available, i.e. as investment decisions are made and as markets clear. You are able to toggle between these two screens and your main input screen at all times – they will show you of how you have done and can inform your decisions for the next round.

Treatment A
For this exercise, there is no forward market. The sequence of events for this exercise is as follows. First, the six sellers must decide how much capacity to add to their generating units. Next, each of the buyers and sellers submit quantity/price bids and offers, respectively, in the spot market. This sequence will be repeated until the exercise ends randomly after 20 periods.

Treatment B
For this exercise, there are six sellers, six active buyers, and X traders in the market. The sequence of events is as follows. The capacity investment subperiod occurs first. Second, the forward market. And third, the spot market. This sequence will be repeated until the exercise ends randomly after 20 periods.

Treatment C
For this exercise, there are six sellers, six active buyers, and X traders in the market. The sequence of events is as follows. First, the forward market. Second, the capacity investment subperiod. And third, the spot market. This sequence will be repeated until the exercise ends randomly after 20 periods.

D.3 Trader Instructions

Background
This is an educational training exercise designed for students in CEE 594/ECON 494. The exercise relates to concepts covered in class on markets and market design, competition, and investment. Participants in this exercise may play the role of 1) a firm who produces electricity, 2) a consumer that buys electricity, or 3) a trader that can buy or sell securities in a forward market. The decisions you make during the exercise will determine your earnings, and you will receive points towards your grade in the course in proportion of your total earnings over the course of the semester. You will maximize the points you receive by maximizing the earnings you obtain. Please do not communicate with any of the other class members outside of your group about this exercise until it has been completed.

General Information
You are a trader. There are X other traders in the market. There are also six sellers/generators of electricity, six active buyers of electricity, and 13 other inactive buyers, meaning they are not played by participants, but by the computer. Each of the buyers, active and inactive, and sellers are located at specific points on the electric grid.

All three types of participants, buyers, sellers and traders, will participate in the forward market by buying and selling electricity futures/derivatives/securities.

Each period will consist of three subperiods: capacity investment, forward market, and spot market. During the capacity investment subperiod, sellers can increase the capacity of their plant by constructing additional capacity or decrease their capacity by not maintaining old units. During the forward market subperiod, sellers and buyers are able to buy and/or sell electricity futures/derivatives/securities that will be fulfilled in the spot market. During the spot market subperiod, sellers offer their physical generation to be sold and buyers place bids on the generation.

You will receive earnings based on earnings in the forward market.

The Transmission Network

In this experiment, the generators and the loads are connected by a transmission network which must be operated at all times in a manner consistent with the laws of physics governing the flow of electricity. A small percentage of the energy produced is dissipated by transmission losses, and the system operator must produce more than the total load. For a given pattern of load, the exact amount generated is dependent on where the power is produced. In addition, the operation of the network is constrained by the physical limitations of the equipment used to generate and transmit the power. This implies that there are limits to the amount of power that can be transmitted from one part of the network to another. Congestion, which occurs when these limits are reached, can sometimes make it impossible for the system operator to utilize inexpensive generation, forcing the system operator to purchase more expensive generation from a different location.

This transmission network consists of two regions. Four of the sellers have their generating capacity located at buses in Region A, while the other two sellers have their generating capacity located at buses in Region B. *[might change due to ownership patterns]*

We will now detail the three subperiods that will occur in each round, highlighting the purpose of the subperiod and the specific decisions that must be made. Though traders do not participate in the capacity investment subperiod or the spot market subperiod, it may be useful to learn about them in order to inform your strategy in the forward market.

Capacity Investment Subperiod

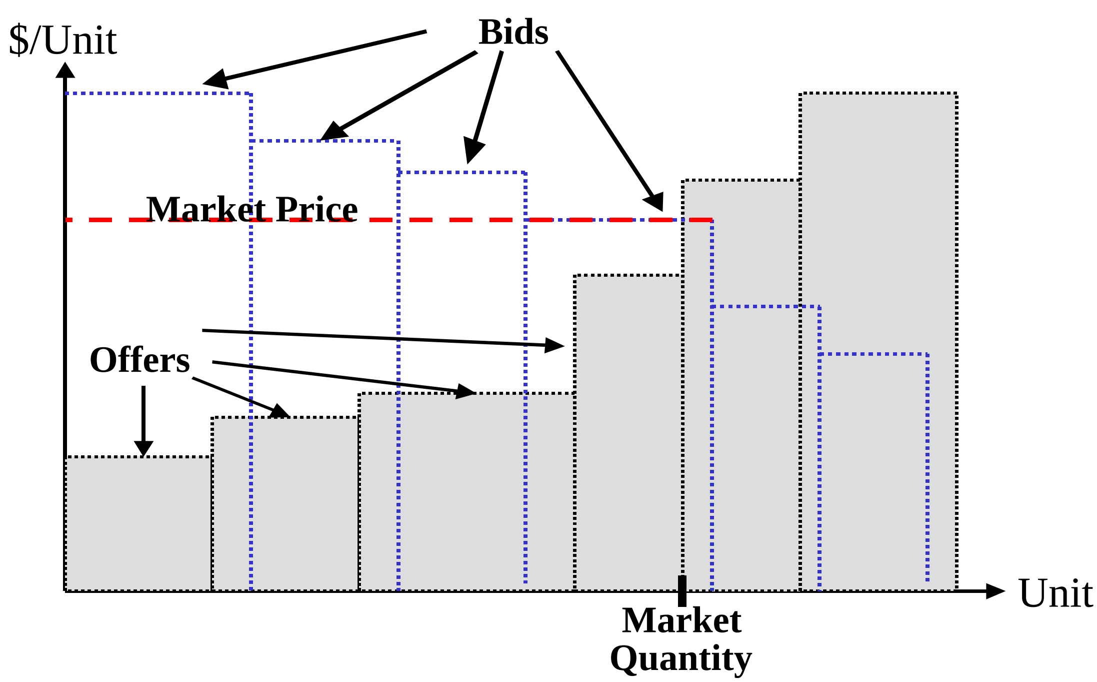
Traders do not participate in the Capacity Investment Subperiod. During this period, sellers are able to invest or disinvest in their generating units to change their capacity. Each of the sellers has an initial generating capacity of X units. Investing and disinvesting in capacity both incur and one time per unit cost of $X and $X respectively. Sellers are limited in their disinvesting options – you can only disinvest X% of your current capacity. There is no limit to how much they can invest. There is also a per unit capacity cost which must be paid for each unit of capacity a seller has after the capacity subperiod is finished. Sellers have time limit of X minutes to make their decisions, afterwards the next subperiod will begin.

Forward Market Subperiod

Due to the physical structure of the electric grid, there are two distinct regions and these regions may have different spot market prices. Thus, each region has its own forward market. Buyers, sellers and traders are able to participate in each of the two forward markets. Each forward market is a purely financial market and the transactions enacted in the forward market do not influence the dispatch or prices set in the spot market. Each player has the ability to submit two offers, two bids, or one offer and one bid into each of the two regions (for a combined total of four offers/bids). The forward market is only half of the transaction though; the rest is fulfilled after the spot market prices have been set. Once the nodal prices in the spot market have been determined, a load-weighted average price is created for each region based on the spot market nodal prices. This load-weighted average price is used to fulfill the transactions made in the forward market. If you buy one or more units in the forward market, then your revenue would be (spot price – forward price)*units bought. Similarly, if you sell in the forward market, your revenue would be (forward price – spot price)*units sold.

For example, suppose you bid to buy two units at $10 in the forward market for region A. The region A forward market clears at $8, so you pay $8 per security for a total of $16. After the spot market subperiod, the load-weighted average price for region A is $11 per unit. You would earn a net forward market revenue of ($11-$8)*2=$6.

A note on strategy. There are a couple of different ways you could use your two offers/bids in each region. If you only want to buy securities, then you could place two bids for different price/quantity pairs. This would allow you to buy a small quantity if the price was high but a larger quantity if the price was low. Vice versa, you could use the same strategy to two offers if you only wanted to sell. Alternatively, you could enter one offer and one bid, with the bid being less than the offer. This would allow you to buy if the price was low and sell if the price was high.



We will determine the market-clearing price in the forward market by intersecting the bids with the offers. Every seller will be paid the same market-clearing price, and every buyer will pay the same market-clearing price. The market price will be the last accepted offer. See diagram above. *(perhaps an average of the last accepted offer and the last accepted bid should be used for the market clearing price. No reason for asymmetry when participants are on both sides of the market.)*

You must indicate whether you wish to buy or sell for each offer/bid in each region and then enter your corresponding price quantity offers/bids. Also displayed on this screen is a forecast of demand for each of the two regions. This forecast provides a useful estimate of actual demand, but can be wrong by as much as X%. *(Pending on the order of the Capacity Investment subperiod and the forward market subperiod, see treatment B vs. treatment C, this forecast can either be more or less accurate than the forecast seen in the capacity investment subperiod. Whichever period occurs first has the less accurate forecast.)*

When you have entered your bids/offers, click the 'Submit Forward Market Decision' button. You will only have X minutes to enter your decision. If you fail to do so in this time, PowerWeb will automatically advance you to the next screen with no offers nor bids in the forward market. Once you hit the submit button, your screen will display a waiting icon, indicating that other participants in your market have not submitted their forward market decisions yet. Once everyone has submitted, your screen will automatically advance to the next subperiod.

Spot Market Subperiod
In the spot market, sellers submit offers to sell electricity and buyers submit bids to buy electricity. Unlike the two forward markets, there is only one spot market. Only sellers are able to submit offers in the spot market. The six active buyers make bids into the spot market and these are combined with the bids of the inactive buyers to complete the demand side of the market.

The Spot Market is based on the physical attributes of the electrical network. After all the offers and bids have been entered, the system operator will choose to accept the least expensive offers which are able to meet the load while satisfying all of the constraints of the transmission system. The prices paid to each supplier are nodal prices, specific to their location. Each nodal price is equal to the marginal cost to the system operator of meeting an additional unit of demand at the corresponding node.

In a network without congestion or losses, a Uniform Price Auction determines the least-cost pattern of generation by paying the Last Accepted Offer to all accepted offers. In this type of auction, the system operator ranks the supplier's offers from the least expensive to the most expensive, and accepts offers in order from the lowest to the highest offer price until sufficient capacity is purchased to meet the load. The system operator pays all purchased capacity the same (uniform) price, and this price is equal to the offer for the most expensive capacity purchased. However, as losses and congestion increase, the system operator is forced to accept offers out of order (some expensive units may be accepted while less expensive ones are rejected), and the prices at the different nodes vary and move away from a single uniform price. In summary, the quantity delivered and price at a given node depends not only on bids and offers, but on the structure of the network.

Results

After you have submitted your bids/offers in the Forward Market Subperiod, PowerWeb will inform you to wait until all of the other suppliers have finished submitting their offers. The results will then be calculated by PowerWeb and presented to you on your Market History screens. You will have two market history screens open at all times, in addition to the screen on which you enter your decisions and bids/offers. One of these screens shows the market history for the two regions separately. The other screen shows your personal market history. Both of these screens will be open at all times and will be automatically updated by PowerWeb as new information becomes available, i.e. as investment decisions are made and as markets clear. You are able to toggle between these two screens and your main input screen at all times – they will show you of how you have done and can inform your decisions for the next round.

Treatment B

For this exercise, there are six sellers, six active buyers, and X traders in the market. The sequence of events is as follows. The capacity investment subperiod occurs first. Second, the forward market. And third, the spot market. This sequence will be repeated until the exercise ends randomly after 20 periods.

Treatment C

For this exercise, there are six sellers, six active buyers, and X traders in the market. The sequence of events is as follows. First, the forward market. Second, the capacity investment subperiod. And third, the spot market. This sequence will be repeated until the exercise ends randomly after 20 periods.