EXPERIMENTAL TESTS OF DEREGULATED MARKETS FOR ELECTRIC POWER: MARKET POWER AND SELF COMMITMENT

1. Executive Summary

1.1 Problems with Deregulation

The deregulation of the electricity industry in the U.S.A. has been implemented in a relatively decentralized way. Individual states or groups of states within a region have developed different approaches to deregulation. Consequently, the structures of the new markets for electricity are very different from one another. For example, eastern markets have favored a more centralized control compared to the Californian market. Nevertheless, major problems in the performance of these markets have arisen, and there is no obvious winner in the design of a market which delivers reliable power to customers in an economically efficient way. Prices, in particular, have been higher and more volatile than expected.

Supplying electricity to customers involves complex interactions among different generators because they share a common transmission network. The characteristics of this network are governed by the laws of physics more than market forces. Many of the traditional assumptions that underlie the performance of a competitive market are violated. For example, different sources of generation are not perfect substitutes for supplying load at a particular location. Competitive prices may vary spatially much more than they do in a typical market with access to a variety of modes of transportation, such as the market for heating oil. In some circumstances, one generator may, in effect, be a perfect monopolist because it is the only generator able to keep voltages within the ranges required to meet reliability standards for one section of the network. However, this situation may only exist for a short time, and at other times, there is no potential for the generator to exploit market power.

Under regulation, system operators had access to a wide variety of information about the operating characteristics and costs of individual power plants. Give this information, it was possible to determine optimum dispatch schedules for individual generators that minimize total operating costs subject to meeting reliability constraints. Even with all of this information, deriving optimum dispatch schedules is a very difficult computational problem for a large network, and in many cases, simplifying assumptions have been adopted to make the computations tractable.

In deregulated markets, the operating characteristics of individual power plants are not public information, and the information needed by a system operator must be provided by generators. However, there is no obligation in a competitive market to submit accurate information. An offer to sell real energy may be substantially higher than the true marginal cost of generation. Similarly, declared ramping rates may be lower and minimum run times higher than the true values. There are no rules in a competitive market that require all generators to submit accurate information about their true costs and operating characteristics.

A truly competitive market would make it difficult to raise profits by submitting false information. Achieving this ideal is, however, very difficult in a complex market structure. In particular, the full amount of information required to determine the unit commitment and dispatch of generators optimally is very large. Unfortunately, the potential for exploiting this complexity to increase profits is also large. Hence, there is a genuine need to determine whether simpler optimization procedures, such as self-commitment by generators, which requires much less information, may work just as well in practice as centralized unit commitment and dispatch. The goal of the experiments described in this report focuses on 1) Can generators exploit market power effectively? and 2) Is self-commitment by generators economically efficient?

1.2 The Role of Experiments

The institutional structure of deregulation in the electricity industry in the U.S.A. is highly decentralized. In effect, a number of experiments are being conducted with real networks, but the consequences of any deficiencies of these new markets are expensive for many of the participants. Experimental economics provides a framework for testing the performance of deregulated markets without the severe economic costs to the public when market structures fail to be competitive.

The experimental platform used at Cornell University to test markets, POWERWEB, is relatively small compared to a typical network for a centralized market. However, POWERWEB simulates a full AC network, and it is able to capture many of the complex issues for acquiring a better understanding of how markets perform under deregulation. In particular, it is possible to design experiments to focus on one specific feature of a market to determine how it affects performance.

Participants in the experimental markets are paid real money in proportion to how well they do in making profits. This framework is surprisingly effective in getting participants to search for weaknesses in the market, and to exploit them when they are found. There is no threat of a telephone call from the Governor, which may stifle behavior in actual markets. Hence, the use of experiments makes it easier to identify the reasons why markets do not perform well, and consequently, offers the potential for designing new market structures that may work better.

1.3 The Results for Testing Market Power

Two different experiments were conducted to test whether participants could identify the potential for exploiting market power in a load pocket. For most experiments, the participants were undergraduates with little knowledge of how electricity systems are operated. In each experiment, six students represented six generators in a market, and two of them were in a load pocket. However, none of the participants knew this information. Their only objective was to make profits by submitting offers to sell power into a centralized auction. By repeating the auction many times (75 in total), the students in the load pocket were, in most cases, able to identify and exploit their market power. Market prices in the load pocket were much higher than the competitive prices outside the load pocket by the end of the experiment.

An identical experiment using utility executives reached similar conclusions, but the learning process, as expected, was faster. The overall conclusion is, however, disturbing. The economic characteristics of a market can be discovered relatively quickly by naïve participants as well as by experts. Since auctions in electricity markets are repeated continuously through time, it is safe to conclude that all possible ways to exploit the market will eventually be found and used to raises prices above competitive levels.

1.4 The Results for Testing Self Commitment

In eastern markets for electricity in the U.S.A., the unit commitment and dispatch of generators is determined centrally in a day-ahead market for the following day. Information about ramping rates, minimum run times and start-up costs, in addition to price/quantity schedules for supplying real energy, are needed to determine economically efficient outcomes that meet engineering constraints. In contrast, Australian markets use a relatively simple optimum power flow for one period at a time, and generators self commit into the market. The only way to ensure that a generator is dispatched is to submit an offer to generate that is lower than the market clearing price. The market in California represents an intermediate structure that incorporates some predetermined schedules for the daily dispatch pattern.

The experiment for self commitment is simplified to an alternating high load/low load sequence. Three types of generator are specified; two peaking units with high operating costs, two shoulder units with lower operating costs and two baseload units with even lower operating costs. However, if a unit was shut down, startup costs had to be paid before the unit operated again. These startup costs were largest for baseload units and smallest for peaking units. Hence, there was an incentive for every unit to generate in all periods and avoid paying startup costs. However, the economic consequences of being shut down were much more substantial for baseload units.

Under these circumstances, it is economically optimum for every unit to make offers in the low load periods below the actual marginal operating costs for the first block of capacity. This is particularly true for baseload units with the highest startup costs. The possibility of making negative profits in a low load period is still more profitable than having to pay startup costs to restart generation in the next high load period. Costs were specified so that optimum offers submitted by peaking units would undercut marginal cost offers submitted by shoulder units in low load periods. In addition, shoulder units would not be dispatched in low load periods unless they submitted offers below operating costs for their first blocks of capacity (because they would be displaced by the second blocks of the baseload units if their corresponding offers were set at the true marginal operating costs). Optimum offers submitted by shoulder units, on the other hand, would shut down baseload units if they submitted offers equal to the true marginal operating costs. Hence, competition in the low load periods was fierce by design. In an optimum solution that minimizes total costs for both the low-load and high-load periods, only the peaking units would cycle on and off. This is a difficult economic problem to solve, particularly by participants in these experiments who had very little knowledge about the operation of electric supply systems.

In spite of the difficulties associated with determining an optimum unit commitment and dispatch, the levels of economic efficiency achieved approached 100 percent by the end of the experiments for undergraduates, graduate students and utility executives. Once again, the utility executives took the least time to reach high levels of efficiency. The overall conclusion is that repeating the auction many times provides an effective way for participants to learn how to avoid paying startup costs by submitting offers below cost in low load periods.

Paying startup costs after a unit is shut down provides a very effective incentive for participants to reevaluate strategies for submitting offers. In fact, the peaking units were generally the first to use aggressive strategies by submitting offers below cost in low load periods. The baseload units, which had the most to lose because of their high startup costs, were relatively slow to reduce offers on their first blocks. One exception was exhibited by one of the utility executives who immediately adopted an optimum strategy for a baseload unit. In this type of complicated market, experience does help. Nevertheless, repeating the auction many times eventually enabled most participants to understand the economic problem and submit appropriate offers. These results are encouraging. Markets scan solve difficult problems efficiently, and it is possible that simple period-by-period auctions may be just as efficient as a complicated day-ahead auction for all periods in the following day.

2. The Experimental Framework for Testing Electricity Markets

2.1 General Procedures for Running Experiments[1]

2.1.1. Subject Pool

The experiments employed undergraduate students enrolled in the business and economics programs at Cornell University. These students were recruited in preference to engineering students because it was felt that utility companies would recruit power marketers and traders from a similar pool. For the purposes of the experiments it was more important to understand the economics of the market than the physical operation of the power grid. While the student subject pools were broadly similar for the market power and the unit commitment experiments, the subjects participating in the unit commitment experiments were more experienced in economics than the students in the market power experiments. The subjects for the unit commitment experiment had previously participated in the second round of market power experiments. To ensure that the undergraduate results were not anomalous or a result of behavior not observed in real markets, a control session of industry professionals was conducted for each set of experiments. A group of graduate applied economics students was also included in the unit commitment experiment. As will be shown in later sections of this report, the main difference between the results from groups with different levels of experience and knowledge of power systems was the time it took to reach an equilibrium strategy.

Table 2-1 summarizes the information relating to the number of students participating in each of the experiments. Each session included six participants representing six different generators.

[1] A copy of the instructions and accompanying documentation for each of the experiments is available upon request from the authors

Table 1-1: Experiment Sessions and Subjects

Experiment Type	*Number of Undergraduate Sessions*	*Other Sessions*
Market Power I	5	1 Executives
Market Power II	6	0
Unit Commitment	6	1 Executives, 1 Graduate Students

2.1.2 Rewards and Duration

Subject Remuneration

It is important that the participants in experiments receive "salient" rewards that correspond to the incentives assumed in the experiments. Performance related payments tend to reduce variability in performance and improve the quality of the results from the experiments[2]. Davis and Holt (1993) define saliency to require:

(1) subjects perceive the relationship between decisions made and the payoff outcomes,

(2) induced rewards are high enough to dominate the subjective costs of making decisions and trades.

Subjects receive monetary rewards based on their profits in the experiments. During the experiment each of the subjects saw their earnings expressed in *experimental dollars* and their real dollar earnings. Real dollar earnings were calculated through the following formula: *Real Dollars = Exchange Rate * Experimental Dollars*.

The exchange rate differed for each generator and across experiments, but the rates were fixed for each entire experiment. The purpose of the exchange rate was to balance potential earnings across generators because different generators had different cost structures and therefore different profit making abilities. The generators were allocated randomly among subjects. There was no fixed limit on potential profits for subjects. Student subjects made on average $30-$50 while the utility executives made on average $100-$200. Losses were capped at zero dollars.

Experiment Length

Table 2-2 summarizes the number of rounds for each of the experiments and each of the sessions. The number of rounds differed because of time constraints. In general the each session was expected to last from two to two and a half hours.

Table 2-2: Length of Experiments in Rounds

Experiment	*Undergraduate*	*Graduate*	*Utility Executives*
Market Power I	75	-	65
Market Power 2	75	-	-
Unit Commitment	60	40	60

[2] See for further discussion Douglas D. Davis and Charles A. Holt, *Experimental Economics*, Princeton University Press, 1993.

2.2 The POWERWEB Platform

POWERWEB is designed to be a flexible Internet-based platform for performing economic experiments. To date the experiments implemented using this platform have focused on examining the behavior of electricity markets using realistic modeling of the physical transmission network and real human decision-makers. Its Internet-based architecture eliminates the need for participants to be physically present in a specially equipped laboratory. The POWERWEB server handles application logic, data processing and computation. Users submit offers to sell power through a standard web browser.

In the electricity markets currently implemented in POWERWEB, each participant in a session plays the role of an owner of a generating plant offering to sell power through an independent system operator (ISO). An example offer submission page is shown in Figure 2-1.

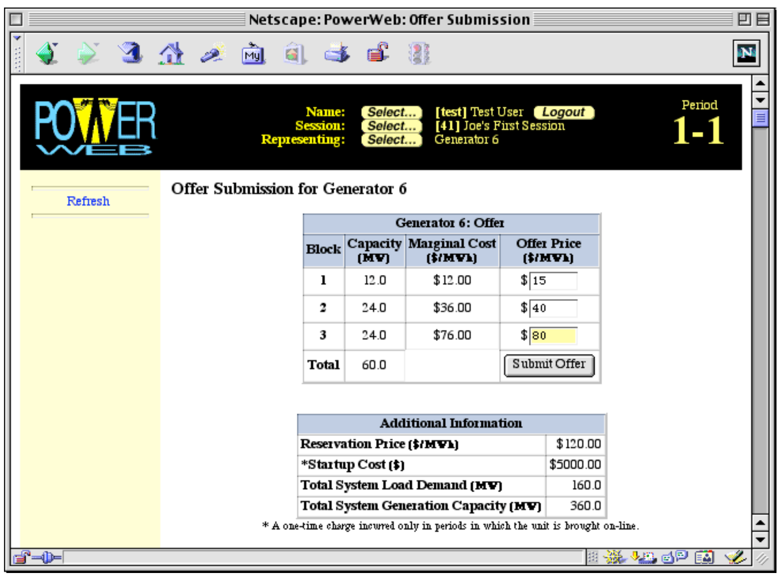
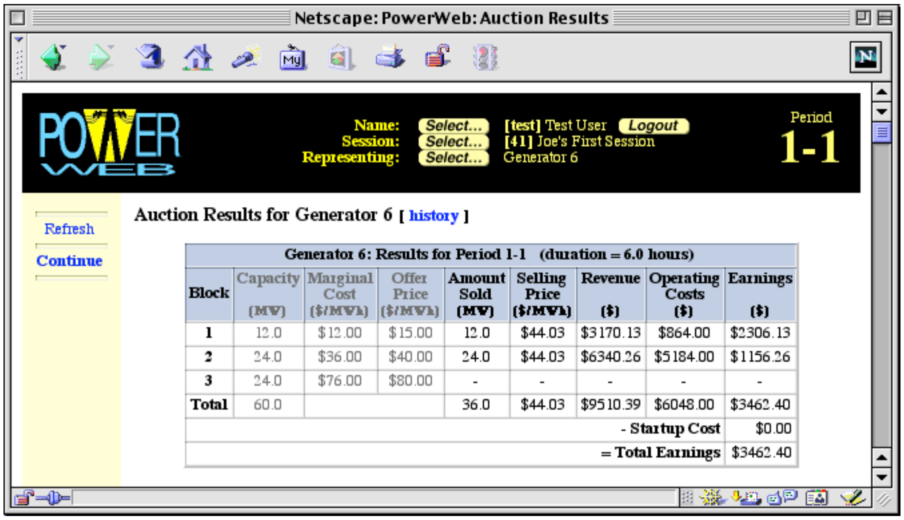


Figure 2-1: Offer Submission Page from PowerWeb

For most experiments, POWERWEB selects the successful offers from competing generators through a uniform price last accepted offer auction. It produces, via an optimal power flow simulation, the market clearing prices and the generation schedules which optimally meet demand (while respecting all of the physical constraints of the power system). The page shown in Figure 2-2 displays the results of a single auction.



Netscape: PowerWeb: Auction Results

Name: Select... [test] Test User Logout
Session: Select... [41] Joe's First Session
Representing: Select... Generator 6

Period 1-1

Refresh
Continue

Auction Results for Generator 6 [history]

Generator 6: Results for Period 1-1 (duration = 6.0 hours)								
Block	Capacity (MW)	Marginal Cost ($/MWh)	Offer Price ($/MWh)	Amount Sold (MW)	Selling Price ($/MWh)	Revenue ($)	Operating Costs ($)	Earnings ($)
1	12.0	$12.00	$15.00	12.0	$44.03	$3170.13	$864.00	$2306.13
2	24.0	$36.00	$40.00	24.0	$44.03	$6340.26	$5184.00	$1156.26
3	24.0	$76.00	$80.00	-	-	-	-	-
Total	60.0			36.0	$44.03	$9510.39	$6048.00	$3462.40
							- Startup Cost	$0.00
							= Total Earnings	$3462.40

Figure 2-2: Auction Results Page from PowerWeb

Figure 2-3 is a diagram of a 30 bus, 6 generator power system whose (some 200) physical characteristics and constraints are modeled by POWERWEB's "smart market".

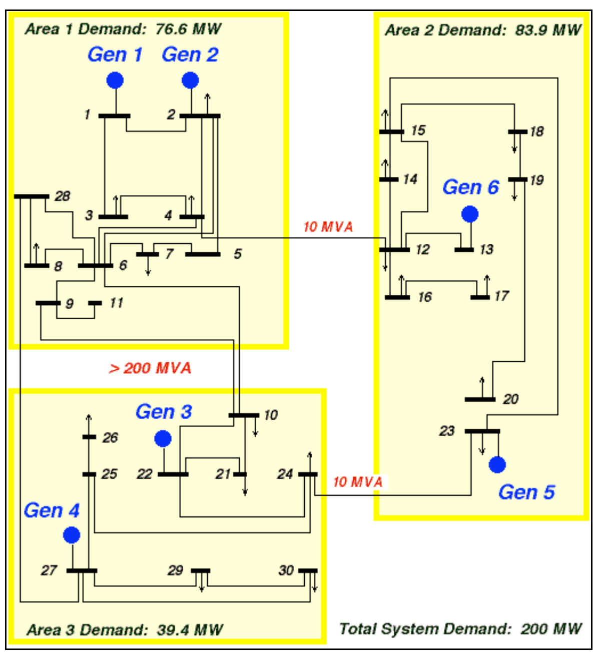


Figure 2-3: Underlying Power Grid for the Experiments

3 Experiment A: Transmission Constraints and Market Power

3-1 Introduction

The capacity of the transmission network will determine the ability of generators in one location to compete for load with generators at different locations in the network. Due to constraints imposed by the transmission grid, it may not always be possible to transfer power from one generator to a given load. The market may be partitioned into smaller "load pockets". Generators able to supply power in a load pocket are presented with the opportunity to exert market power because the constrained transmission link reduces the intensity of competition between generators inside and outside of the load pocket. This occurs even if these generators represent only a small proportion of total generation capacity in the whole network. Transmission lines can be constrained either because of the physical insufficiency of supply inside the load pocket and/or by the pricing and production decisions made by the load pocket generators (Borenstein, *et al.*, 1999a, Hogan, 1997). Both Hogan and Borenstein *et al.* show theoretically how generators can benefit from higher prices as a result of diminished competition from generators outside of the load pocket, and how they can induce transmission constraints to bind through limiting their own generation levels. In essence, generation is reduced inside the load pocket, forcing increased power flows into the load pocket, constraining the transmission lines at their maximum capacity. The load pocket generators are then free to maximize profits from residual demand (usually producing a Cournot-Nash equilibrium). Hogan's most important contribution to this debate has been to show that market power is endogenous to the strategies pursued by the generators in the market (Hogan, 1997). In complicated networks, the effect of actions at one node can have strong interactions with conditions at other nodes. It is possible, therefore, to leverage one's position in the network to limit the ability of other generators in order to compete.

Electricity auctions involve the submission of price/quantity supply functions (offer curves) by participants. Consequently, it is unrealistic to analyze competition in terms of either Cournot or Bertrand competitions where the instrument of control is either quantity or price. Klemperer and Meyer (1989) modeled an oligopoly facing an uncertain demand in which it must choose a "supply function" strategy to relate quantity to price. They hypothesize that prices will tend towards a Cournot solution if 1) the marginal cost curve of production is steep relative to the demand curve, 2) there are the fewer firms, 3) products are highly differentiable, and 4) demand uncertainty is greatest at the highest prices. This approach is appealing because of its similarities to the problem faced by power producers. Indeed Green and Newbery (1992) extend this approach, in their analysis of the British electricity market, to show that prices tend to be greater than marginal cost in markets of this type.

The possible impact of transmission constraints in reducing competition inside load pockets has been understood for some time. Numerous attempts have been made to empirically measure the scope for market power. Spann (1976) and Schmalensee and Golub (1984) determined that most geographically defined Department of Energy regions could support a sizeable number of efficiently sized competing firms. Some regions, however, lacked sufficient transmission capacity to constitute a single market (producing excessively large Hirschman-Herfindahl Index [HHI] values). Other studies have attempted to identify the existence of market power through variations in the Lerner index. Both the California Power Exchange (1998a,b) and Borenstein *et al.* 1998 use similar methods to show that prices in Northern California are sustained above competitive levels during certain periods due to limitations on transmission capacity into the region (Bohn, *et al.*

1998). Wolfram (1999) has produced similar results for the UK market and for the Norwegian market where transmission constraints produced higher prices in isolated regions (Johnsen, *et al.*, 2000).

An alternative approach has been to simulate Cournot competition using real market data for estimates of demand, supply, transmission constraints and production costs. Borenstein *et al.* (1999b) used this approach to show how producers can increase prices in California as demand increases and transmission constraints bind. This approach is repeated for an analysis of New Jersey, which can be considered a load pocket because of the limited transmission capacity into the region. Again, they show that as demand increases it becomes optimal for the load pocket generators to increase their prices (and/or reduce their supply quantities). Whereas measures of market concentration such as the HHI or Lerner index can provide an ex-post indication of the existence of market power, this simulation of optimal strategies can produce an *a priori* measure of monopoly power.

Vernon Smith and his colleagues conducted a series of experiments using a radial network with a central buyer node and generators located at each end of the line. By constraining the transmission capacity of one of the two lines they examined whether generators in the load pocket were able to secure higher than competitive prices. Surprisingly, they found that the load pocket generators did not raise prices. It was the generators outside of the load pocket who raised their prices and secured the available rent from the transmission constraint (Backerman, *et al.,* 1997b). Bernard believes that this is a result of the specific nature of their network and experimental design since it contradicts prevailing expectations (Bernard, 1999).

Previous research has concentrated on markets with relatively simple power grids, and little attention has been paid to the extensive interaction of the network with markets. Either implicitly or explicitly, it is frequently assumed that electricity is a homogenous product,, but in complicated electricity networks this is entirely incorrect. To the consumer, one unit of electricity is the same as another, and it is impossible to determine exactly where that power originated in the network. From a supply perspective, however, different sources of power are not perfect substitutes. In this sense, the sources are differentiated.

Generators produce two rival simultaneous products, real and reactive power. Real power (measured in MWh) is the energy used by the load. Reactive power (measured in VAr) cannot be used directly by the load but it is essential for controlling voltage. Since load requires real power to be within strict voltage limits, VArs are essential for the operation of the power grid. Reactive power can be positive or negative and be used to increase or decrease voltage. For a generator, supplying reactive power may or may not compete with supplying real power. If supplying reactive power causes a generator to produce less real power, payments are made in some markets corresponding to the opportunity cost of the reduced output of real power. However, under nodal pricing, the locational marginal prices will reflect the costs of supplying both real and reactive power. One advantage of using an AC network in POWERWEB is that the correct nodal prices can be derived, and generators are paid these prices in experiments.

Nodal prices are very sensitive to the injections of reactive power necessary to maintain voltage and other operating conditions. Reactive power is a localized product that cannot be transported effectively through the network. Injections of reactive power affect only network conditions in the immediate vicinity. A generator may be essential for reactive power purposes even though its production costs are too high to enter the energy market. In essence, the production of power at one node in the network is not a perfect substitute for power produced at another node. In some instances, a generator can become a localized monopoly. As a result, system operators have developed procedures for identifying when generators face "must run" conditions, and typically, offers from these generators are not allowed to set market prices in the auction.

3.2 Monopoly Power: Experiment I

3.2.1 The Design of Experiment I

Two sets of experiments were conducted to examine whether generators inside a load pocket could identify and exploit the reduced intensity of competition caused by a transmission constraint. Each experiment employed a six generator, 30-node alternating current (AC) network, as shown in the previous section. In each experiment, the network was divided into two regions (A and B) joined by transmission links with finite thermal capacities. Each region had a separate demand that could be satisfied by any of the six generators operating subject to the transmission constraints. Figure 3-1 shows a schematic representation of the network for the first set of experiments.

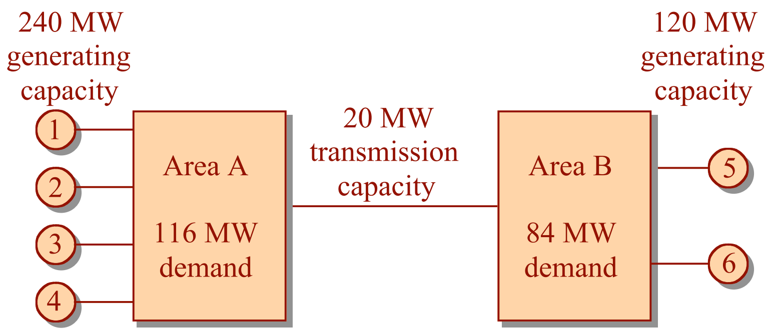


Figure 3-1: Transmission Network Block Diagram

Area B is the load pocket. Served by only two generators with only limited competition from the other four generators, prices in this region are expected to be higher than competitive levels. In addition to the limit on imports into Area B, the two generators inside the load pocket are imperfect substitutes. There are actually two transmission lines into the load pocket. If either of the generators inside the load pocket generates less, the net demand at the end of one transmission line is increased. This causes increases in the flow of energy towards the node where the demand has increased, including flows from outside of the load pocket. In order to prevent the line from being overloaded when it is already at full capacity, some capacity outside the load pocket must be backed down, representing an additional cost to the system. Generators in the load pocket can raise their offers until the marginal cost of their energy equals the marginal cost of backing down generation outside the load pocket. The configuration of this network implies that generator 6 is in a more favorable location than generator 5. Generator 6 will be backed down at a slower rate than generator 5 in response to making higher offers. The transmission constraint, therefore, has both a direct effect that limits flow of real energy into the region and an indirect effect caused by voltage support that affects nodal prices for all generators.

Table 3-1 shows the cost parameters and block sizes for the six generators in the experiment. Each generator was divided into three blocks of capacity with different marginal costs. Generators 1 through 4 were located outside the load pocket in Area A. Generators 5 and 6 were located inside the load pocket in Area B. Note that in this experiment, the six generators are identical in cost and size.

Table 3-1: Generator Costs and Capacities for Experiment I

Generator	*Block 1*		*Block 2*		*Block 3*	
	MW	$/MW	MW	$/MW	MW	$/MW
1	12	20	24	40	24	50
2	12	20	24	40	24	50
3	12	20	24	40	24	50
4	12	20	24	40	24	50
5 – Inside Load Pocket	12	20	24	40	24	50
6 – Inside Load Pocket	12	20	24	40	24	50

Given the costs in Table 3-1, the competitive market solution corresponds to generators submitting offers equal to the true marginal costs. The competitive solution is shown in Table 3-2. Using the Last Accepted Offer (ALO) to determine the market clearing price, the second blocks of generators 1 and 3, which are partially dispatched, set the market price at $40/MWh. The higher model prices paid to the other generators reflect network constraints and losses. However, the transmission constraints from region A to region B are not binding because only 12 MW of real energy is transmitted on lines that have a maximum capacity of 20 MW.

Table 3-2: The Competitive Market Solution for Experiment I

Generator	*MW Dispatched*	*Nodal Prices $/MWh*	
		LAO	FRO
1	23.96	40.00	48.40
2	36.00	40.08	48.48
3	34.90	40.00	48.40
4	36.00	40.13	48.53
5 – Inside Load Pocket	36.00	41.10	49.50
6 – Inside Load Pocket	36.00	41.60	50.00

* LAO Last Accepted Offer
FRO First Accepted Offer

Since the aggregate marginal cost curve for all generators is a step function, generators can raise the competitive price above the LAO, without altering the efficient pattern of dispatch, until the next most expensive block is reached. This latter situation corresponds to setting the market price to the First Rejected Offer (FRO) of $50/MWh for generator 6. The difference between the LAO and FRO prices represents the potential range of competitive prices. In the experiments, the expectation is that prices outside the load pocket will be in this range, and that prices in the load pocket will be higher than the FRO.

Total system demand is 200 MW and it is completely inelastic[3]. The load pocket has a demand of 84 MW. Each of the generators has a capacity of 60 MW. If the transmission line is constrained, which it will be if the price inside the load pocket is even slightly above the price outside the load pocket, then only 20 MW of capacity can be imported into the load pocket. This leaves a residual of 64 MW of load that must be divided between 120 MW of generating capacity. Since

[3] At present most deregulated markets model demand to be perfectly inelastic. Only a small percentage of the load is price sensitive and so the assumption of perfect inelasticity in the experiments is not unreasonable.

the required generation of 64 MW in the load pocket is greater than the 60MW capacity of a single generator, both generators in the load pocket are essential. If one generator raises its offer to the maximum allowed price (the reservation price of $80/MWh) and the other generator submits offers below the reservation price, then the latter generator will be fully dispatched at 60 MW. 4 MW will be supplied by the generator submitting offers at the reservation price, and this will set the marginal price in the load pocket. Additional capacity cannot be imported from outside of the load pocket even if the offers are much lower. The actual situation is slightly more complicated because generators have a minimum capacity requirement corresponding to the first block of 12MW. Since both generators are essential in the load pocket, each generator must operate at least the first block of capacity even if the offer is at the reservation price. Von der Fehr and Harbord (1993) point out, however, that one of the generators can increase its profits by submitting lower offers. By selling greater capacity at the reservation price (set by the other generator), profits are increased. This position can be maintained by offering capacity at a price low enough to ensure that the other generator's payoff is reduced if it tries to undercut the low offers.

3.2.2 The Results for Experiment I

Figure 3-2 shows a comparison of the average prices inside and outside the load pocket for all of the undergraduate sessions. Prices in the load pocket, by the end of the experiment, were much higher than those outside of the load pocket. The straight dashed line at $48/MWh represents the maximum competitive price If all generators submitted had offers at the true marginal costs, the last accepted offer (LAO) would $40/MW. In these circumstances, the first rejected offer would have been $50/MW and therefore prices between $40/MWh and $50/MWh can be considered competitive.

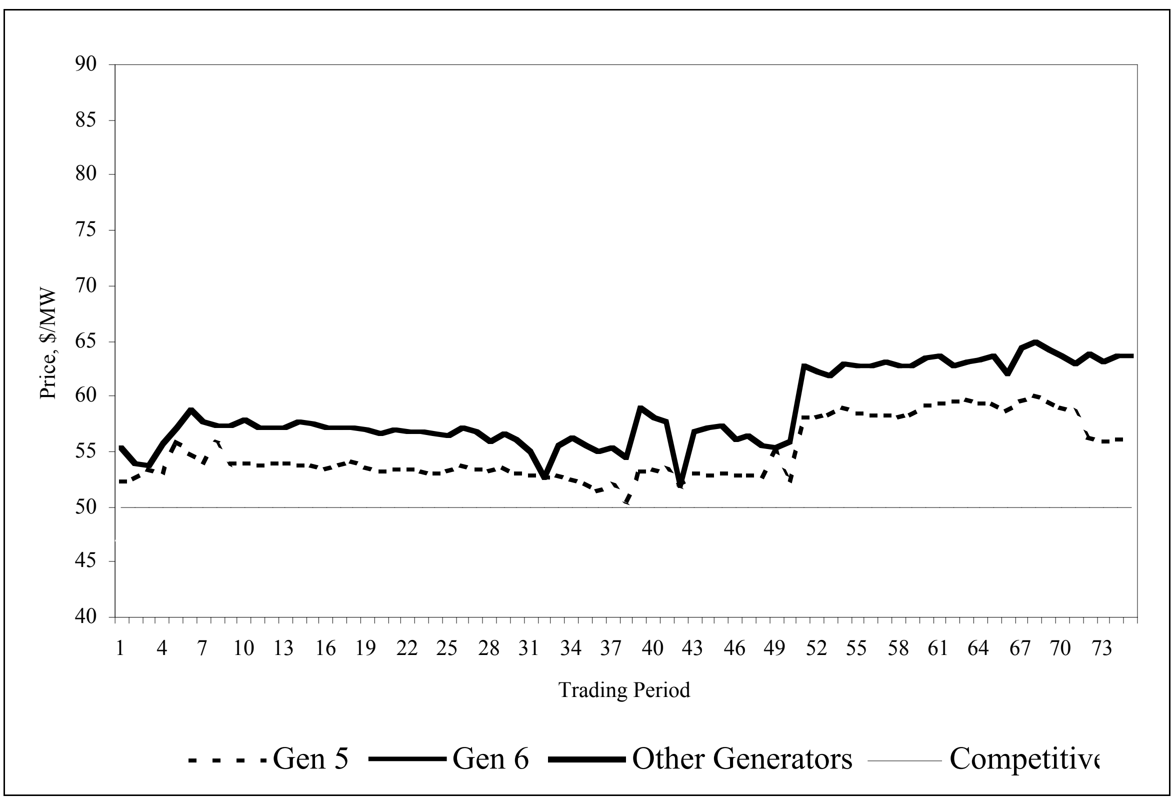


Figure 3-2: Average Prices in Undergraduate Sessions

The price outside the load pocket seldom differs greatly from $48. The fact that prices are close to the upper boundary of competitive prices would suggest that with only four participants the market is likely to be less than perfectly efficient. This is supported by previous experimental examinations of LAO multiple unit auctions by Bernard *et al.* (1998) who show that six participants are needed to be efficient. Inside the load pocket, prices are on average moderately higher than the upper boundary of competitive prices until the last twenty rounds of the experiment. During the last twenty rounds average prices in the load pocket jump, with generator 6 (as expected) being the price leader.

Figure 3.3 shows the same comparison of prices from the experiment with utility executives. Note that essentially the same result is achieved with prices outside the load pocket approximately competitive while prices insides the load pocket are substantially higher (with generator 6 leading in price). The main differences between the executives and the undergraduates are the speed with which the subjects appreciated the degree of market power they possessed the higher prices inside the load pocket, and the use of signaling by generator 6. Dropping the offers from the reservation price to marginal cost in some periods is an attempt to get generator 5 to raise its offers. In duopoly experiments, Bernard *et al.* (1998) found that the two participants generally reached some tacit agreement to share the responsibility for raising the market price.

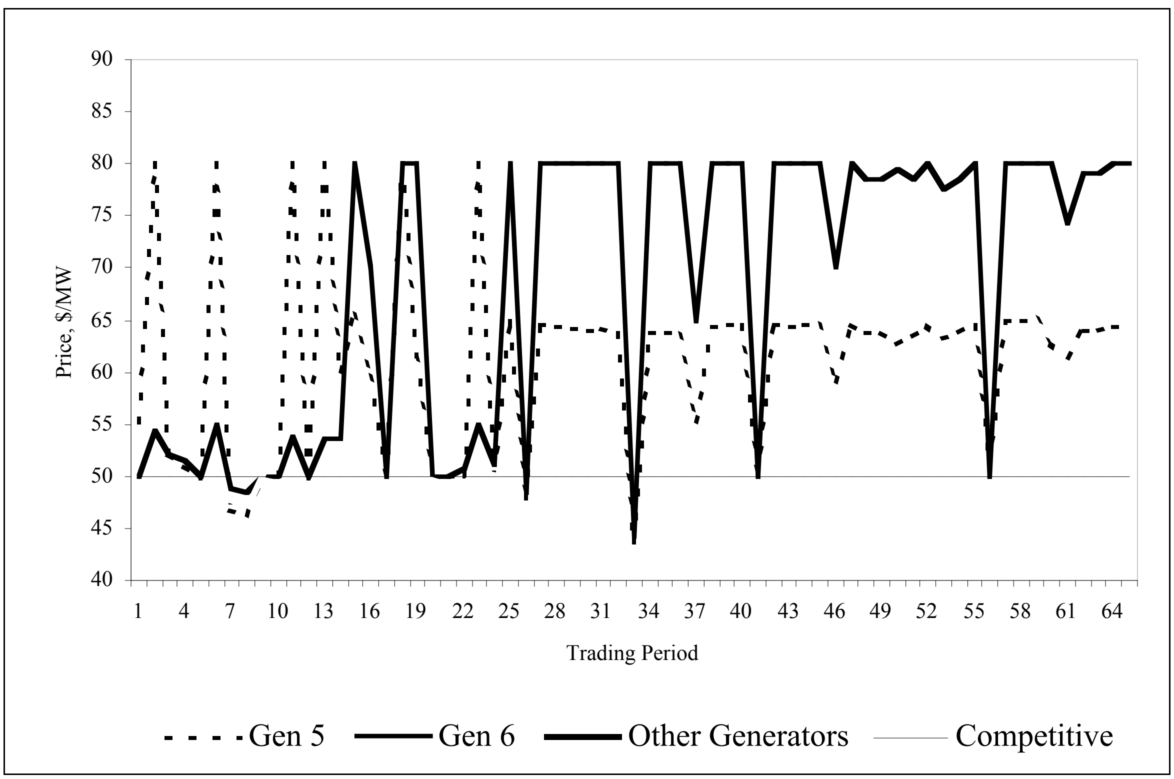


Figure 3-3: Average Prices in Utility Executive Session

It is appropriate to examine the descriptive statistics resulting from the six different sessions of this experiment. Table 3.3 shows the average price, standard error and confidence interval of average prices outside the load pocket during the last ten periods of each session[4]. An F-Test was conducted for each session for the null hypothesis that the mean prices received by generators 1 through 4 (outside the load pocket) were equal. Accepting the null hypothesis that the prices were equal would justify the use of a grand mean and pooled standard error to describe prices outside the load pocket. The null hypothesis was accepted in four of the five undergraduate sessions but was rejected for the session with the utility executives. However, the price history outside of the load pocket is only of limited interest, and the grand mean is calculated for each session for the sake of brevity. The results from the statistical analysis confirm the qualitative analysis in Figures 3-2 and 3-3. Prices outside the load pocket were on average well above the LAO but below the FRO. Only one of the 95% confidence intervals for the average price includes the FRO ($50/MWh), and all six are significantly above the LAO ($40/MWh).

[4] The last ten periods are used in order to eliminate the learning process inherent in any experiment. It is assumed, therefore, that subjects have settled on a consistent strategy during the last ten periods.

Table 3-3: Average Prices Outside the Load Pocket ($/MWh)

	Average	*Standard Error*	*95% Confidence Interval*		*Price > 40*	*Price < 50*
Session 1	47.95	0.17	47.60	48.29	Yes	Yes
Session 2	46.08	0.40	45.28	46.89	Yes	Yes
Session 3	44.74	0.64	43.46	46.02	Yes	Yes
Session 4	50.49	0.31	49.87	51.11	Yes	No
Session 5	48.89	0.28	48.32	49.46	Yes	Yes
Utility Executives	47.29	0.27	46.74	47.83	Yes	Yes

An F-Test was conducted to test the null hypothesis that the average price received by generators 5 and 6 could be aggregated across all undergraduate sessions. It was rejected. This is logical because the exercise of market power varied between the sessions. The prices, therefore, were likely to be substantially different. A second F-Test was conducted for the null hypothesis that the average price received by generator 5 and 6 were equal on a session-by-session basis. It was rejected for all but one of the five undergraduate sessions and for the utility executive session. For this reason, we present the results are presented by session for both generator 5 and generator 6 in Tables 3-4 and 3-5.

Table 3-4: Average Prices for Generator 5 ($/MWh)

	Average	*Standard Error*	*95% Confidence Interval*		*Price < 50*	*Price > 50*
Session 1	49.39	0.14	49.06	49.71	Yes	No
Session 2	61.70	0.60	60.34	63.05	No	Yes
Session 3	48.51	0.88	46.53	50.49	No	No
Session 4	75.04	1.99	70.53	79.54	No	Yes
Session 5	54.83	0.22	54.33	55.33	No	Yes
Utility Executives	62.69	1.34	59.65	65.73	No	Yes

Table 3-5: Average Prices for Generator 6 ($/MWh)

	Average	*Standard Error*	*95% Confidence Interval*		*Price < 50*	*Price > 50*
Session 1	50.10	0.06	49.96	50.25	No	No
Session 2	75.87	1.13	73.32	78.42	No	Yes
Session 3	50.64	0.72	49.02	52.27	No	No
Session 4	79.50	0.50	78.37	80.63	No	Yes
Session 5	62.09	0.32	61.36	62.81	No	Yes
Utility Executives	76.23	2.97	69.52	82.93	No	Yes

Market power was not exerted in every session by the undergraduates. In sessions 1 and 3, prices for generators 5 and 6 did not increase much above the FRO of $50/MWh. In the other undergraduate sessions, generators 5 and 6 both received prices significantly above the competitive level, with generator 6 setting the price.[5] It is quite evident that the utility executives exercised market power effectively and raised prices in many periods to the maximum reservation price ($80/MWh).

Figures 3-5 and 3-6 show graphically the ranges of prices observed in the undergraduate sessions. They show that many periods prices were close to the reservation price. Generator 6 was the first one to realize the scope for market power. Generator 5 was not able to raise until later in the experiment.

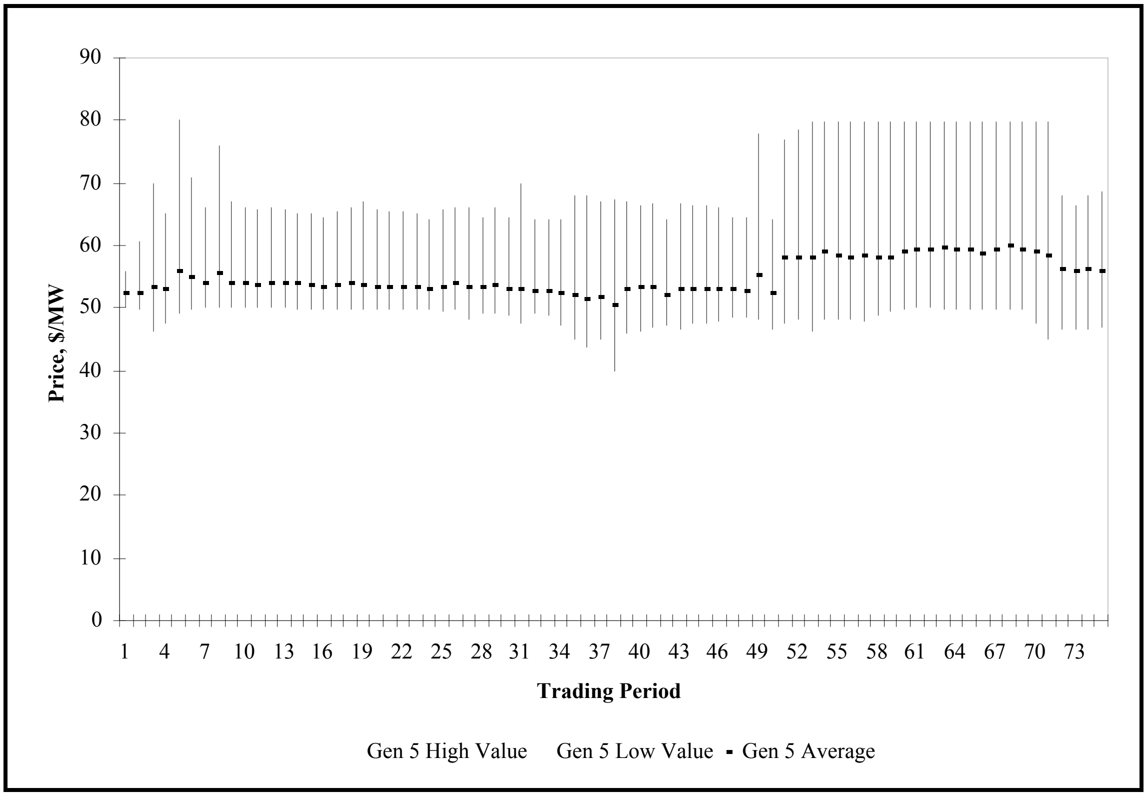


Figure 3-4: Generator 5 Price Ranges (Undergraduates)

[5] As predicted by Von der Fehr and Harbord, the price setting generator 6 sells only residual demand and the bulk of load is supplied by generator 5. An analysis of the dispatch of generators 5 and 6 and resulting profits shows that the price leader, generator 6, was dispatched at close to minimum capacity. This greatly increased profits for generator 5 over the competitive FRO. Generator 6 was on average better off than if prices were at the FRO.

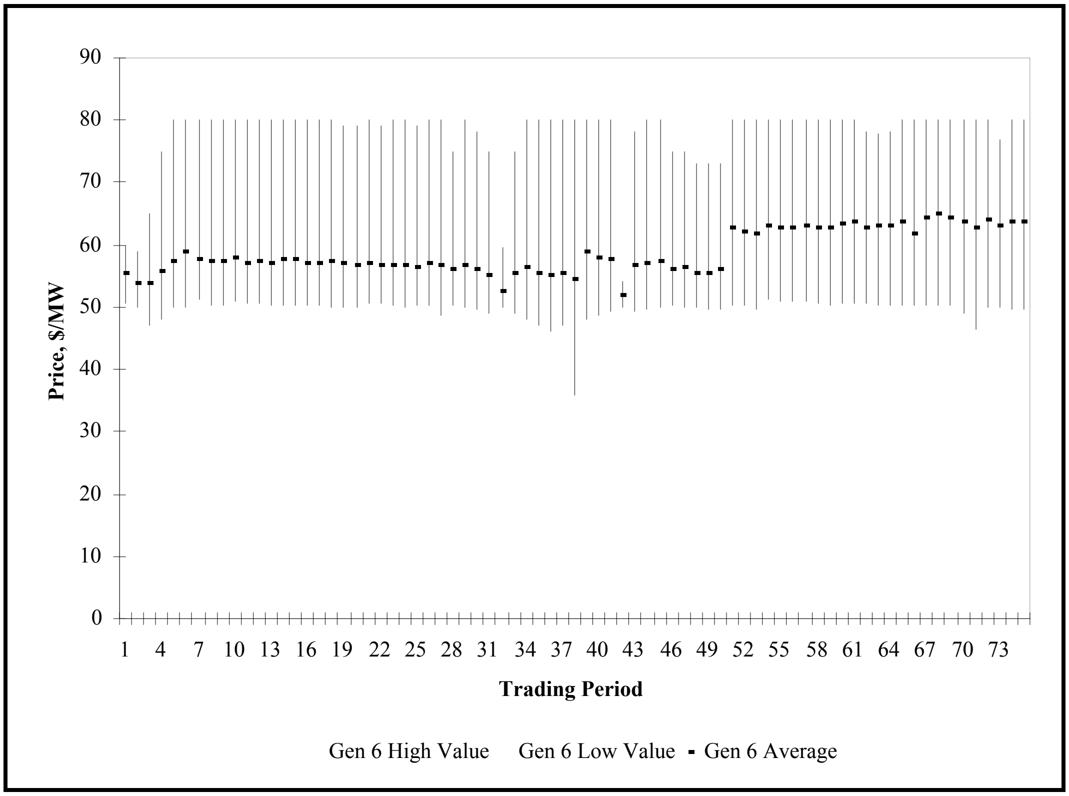


Figure 3-5: Generator 6 Price Ranges (Undergraduates)

3.3 Monopoly Power: Experiment II

3.3.1 The Design of Experiment II

The first market power experiment can justifiably be considered as an easy situation for generators in the load pocket to exploit. Since both generators 5 and 6 eventually find out that their services are essential to meet demand, they can increase their profits by raising their offers. The only competition between them will be to determine how much of their capacity is dispatched. A second set of experiments was conducted to examine a case in which cost differences result in a transmission constraint which creates a load pocket for generators 5 and 6. The market was again partitioned into two areas (A and B) with area B being the load pocket. Demand throughout the system is completely inelastic, but the demand inside the load pocket was reduced from 84MWh to 49MWh. If one generator was completely shut down, demand could be entirely satisfied by the other generator. This would ensure that neither generator inside the load pocket was essential to the operation of the system. This was not the case in Experiment I.

The transmission line was constrained because the marginal costs for the two generators inside the load pocket were higher than the marginal costs of the generators outside the load pocket. With marginal cost offers, energy would flow to the maximum extent into the load pocket from outside, and power flow along the transmission line would be at its maximum of 20MW. Table 3-6 shows the new cost and capacity parameters of each generator in the experiment. The changes from Experiment I are bold.

Table 3-6: Generator Costs and Capacities for Experiment II

Generator	*Block 1*		*Block 2*		*Block 3*	
	MW	**$/MW**	**MW**	**$/MW**	**MW**	**$/MW**
1	12	20	24	40	24	50
2	12	20	24	40	24	50
3	12	20	24	40	24	50
4	12	20	24	40	24	50
5 – Inside Load Pocket	**12**	**45**	**24**	**55**	**24**	**60**
6 – Inside Load Pocket	**12**	**45**	**24**	**55**	**24**	**60**

The competitive solution for Experiment II is summarized in Table 3-7. Each of the generator's inside the load pocket sell at close to the minimum generating limits, and the transmission lines are used to the maximum of 20 MW. There are, in effect, two separate markets, and different blocks set the prices inside and outside the load pocket. The ranges of competitive prices are $40/MWh to $50/MWh outside the load pocket, and $54.27MWh to $55.73/MWh inside the load pocket. This changes the nature of the indirect market power afforded by the transmission constraint.

Table 3-7: The Competitive Market Solution for Experiment II

Generator	*MW Dispatched*	*Nodal Prices $/MWh*	
		LAO	FRO
1	31.72	49.85	40.00
2	36.00	50.00	40.15
3	34.03	49.85	40.00
4	36.00	49.99	40.14
5 – Inside Load Pocket	17.57	55.73	55.00
6 – Inside Load Pocket	12.00	55.00	54.27

* LAO Last Accepted Offer
FRO First Accepted Offer

In the previous experiment, changes in the dispatch levels of generators 5 and 6 affected the flow of energy throughout the system, and it was necessary to alter the dispatch of some generators outside the load pocket. In this experiment, the effects are minimal. With generators 5 and 6 operating close to their minimum limits, the question arises as to the impact of turning one generator off completely and serving load entirely from imports and the remaining generator in the load pocket. Since reactive power is a local product that cannot be transported, turning off one generator will have a major impact on voltage in the network. The effect is to increase the amount of reactive power required on one transmission link (and by definition this reduces the amount of real power supplied by that link). For example, if generator 5 was turned off, the reactive power requirement is such that generator 6 must supply 36 MWh of power. This is greater than the 29 MW ordinarily produced inside the load pocket when both generators are operating efficiently because the transmission link's ability to carry real power has been reduced. Consequently, generator 5's first block of capacity is competing against generator 6's third block of capacity. Taking into account losses in the transmission network, generators 5 and 6 could raise their prices to about $60/MWh with impunity. Above that price, the market adopts the characteristics of

Bertrand price competition, with each generator possessing sufficient profit incentive to undercut the other and thus ensure dispatch.

3.3.2 The Results of Experiment II

Figure 3-6 compares the average prices outside the load pocket across all of the undergraduate sessions against the prices received by generators 5 and 6, inside the load pocket. All four generators outside the load pocket would sell most of their second block of capacity. Competition for load would be with the third blocks of other generators which are priced at $50/MW, and the range for competitive prices is $40-$50/MWh. It is evident that the average price outside the load pocket converged on the upper boundary.

Inside the load pocket, only a small proportion of one of the generator's second block is sold, leaving a large balance of capacity priced at $55/MWh. This would be, therefore, the price at which competition for load occurred. It has already been established that the transmission constraint affords generators 5 and 6 the ability to raise their prices to $60/MWh range without reducing sales. Prices in the range $55 to $60/MWh present increasing profits to higher offers. One would expect prices to rise to the upper boundary of this range under competition, since the lowest offer from either generator above $60/MWh will shut the other generator down. This is Bertrand price competition. Given that it takes a number of rounds for the subjects in the experiment to understand the workings of the auction and the extent of market power, it is unlikely that the experiment was long enough for the generators to tacitly collude to drive prices higher. The results show that both of the generators inside the load pocket were able to drive their prices up to the $60-65/MW range. It is clear that prices are higher than competitive levels.

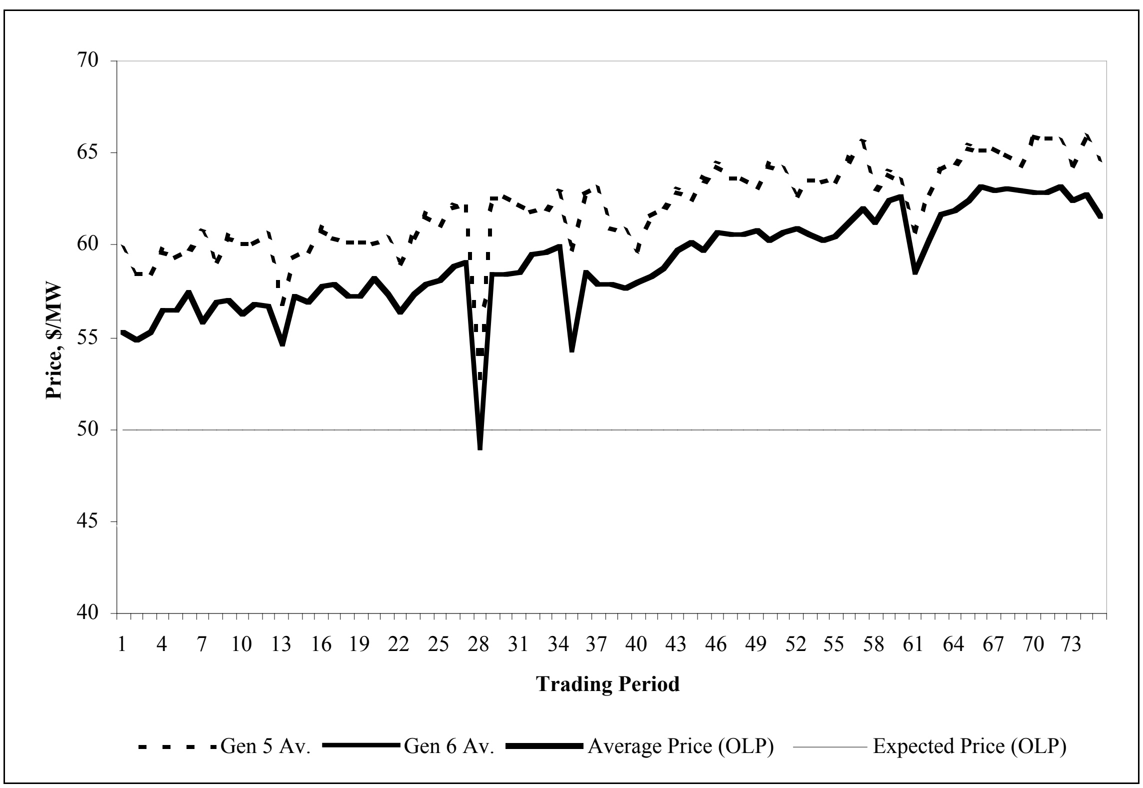


Figure 3-6: Average Prices in Undergraduate Sessions

Table 3-8 shows the average price, standard error and confidence interval of average prices outside the load pocket during the last ten periods of each session. A prior F-Test was conducted for each session with the null hypothesis that the mean prices received by generators 1 through 4, outside of the load pocket, were equal for the last ten periods. Under the null hypothesis, using a grand mean and pooled standard error for prices outside of the load pocket is justified. The null hypothesis was accepted in four of the six sessions. However, the price history outside of the load pocket is only of limited interest and the grand mean is presented for each session for the sake of brevity[6]. The results from the statistical analysis confirm the qualitative analysis from Figure 3-6. Confidence intervals for the mean prices outside the load pocket were above the LAO and in most cases below the FRO. Hence, prices outside the load pocket were generally competitive.

Table 3-8: Average Prices Outside the Load Pocket ($/MWh)

	Average	*Standard Error*	*95% Confidence Interval*		*Price > 40*	*Price < 50*
Session 1	49.00	0.12	48.77	49.24	Yes	Yes
Session 2	48.573	0.15	48.27	48.88	Yes	Yes
Session 3	48.79	0.07	48.66	48.92	Yes	Yes
Session 4	50.33	0.05	50.23	50.43	Yes	No
Session 5	49.91	0.41	49.09	50.73	Yes	No
Session 6	49.45	0.09	49.26	49.63	Yes	Yes

An F-Test was conducted with the null hypothesis that the average price received by generators 5 and 6 could be aggregated across all undergraduate sessions in the last ten periods. It was rejected because the exercise of market power varied between the sessions. The prices, therefore, were likely to be differently distributed. A second F-Test was also conducted with the null hypothesis that the average price received by generators 5 and 6 were equal on a session-by-session basis. It was accepted for only one undergraduate session. Therefore, the results are presented by session for both generator 5 and generator 6 in Tables 3-9 and 3-10.

Table 3-9: Average Prices for Generator 5 ($/MWh)

	Average	*Standard Error*	*95% Confidence Interval*		*Price > 55.73*
Session 1	60.54	0.72	58.91	62.17	Yes
Session 2	72.031	0.98	69.82	74.25	Yes
Session 3	70.5	0.69	68.95	72.05	Yes
Session 4	66.113	0.03	66.04	66.19	Yes
Session 5	60.505	0.91	58.44	62.57	Yes
Session 6	61.147	0.16	60.78	61.52	Yes

[6] The average generator prices outside of the load pocket in sessions where the F-Test null hypothesis was rejected do not convey any particularly different information than expressed in a grand mean. In sessions 3 and 4, the prices for two generators were slightly above $50/MWh and two were slightly below $50/MWh.

Table 3-10: Average Prices for Generator 6 ($/MWh)

	Average	*Standard Error*	*95% Confidence Interval*		*Price > 55*
Session 1	58.094	0.51	56.94	59.25	Yes
Session 2	69.999	1.15	67.40	72.60	Yes
Session 3	63.21	0.19	62.78	63.64	Yes
Session 4	70.944	0.12	70.67	71.22	Yes
Session 5	55.423	0.01	55.41	55.44	Yes
Session 6	59.002	0.19	58.57	59.43	Yes

In every session, generators 5 and 6 raised prices significantly above the competitive FRO. The highest prices of $70/MWh were observed in sessions 2, 3 and 4. For this to have occurred, some tacit collusion was required between the generators 5 and 6. This was achievable because one generator raised offers sufficiently to ensure that the other generator did not get shut down. In other sessions, both generators raised their prices above the competitive FRO, but generator 6 persisted to submit relatively low offers, and generator 5 could not increase the market price without being shut down. One of the two generators was shut down in only 5 out of a total of 450 periods.

Figures 3.7and 3.8 show graphically the range in prices observed for generators 5 and 6 in all sessions of the experiment. They show that prices for each of the generators increased gradually with generator 5 showing generally higher offers by the end of the experiment. As subjects gained experience, they were able to take advantage of the market power inherent in the load pocket. In most cases, the minimum prices observed were closest to the competitive levels and the maximum prices were close to $70/MWh. These high levels, however, were lower than the maximum prices observed in Experiment I.

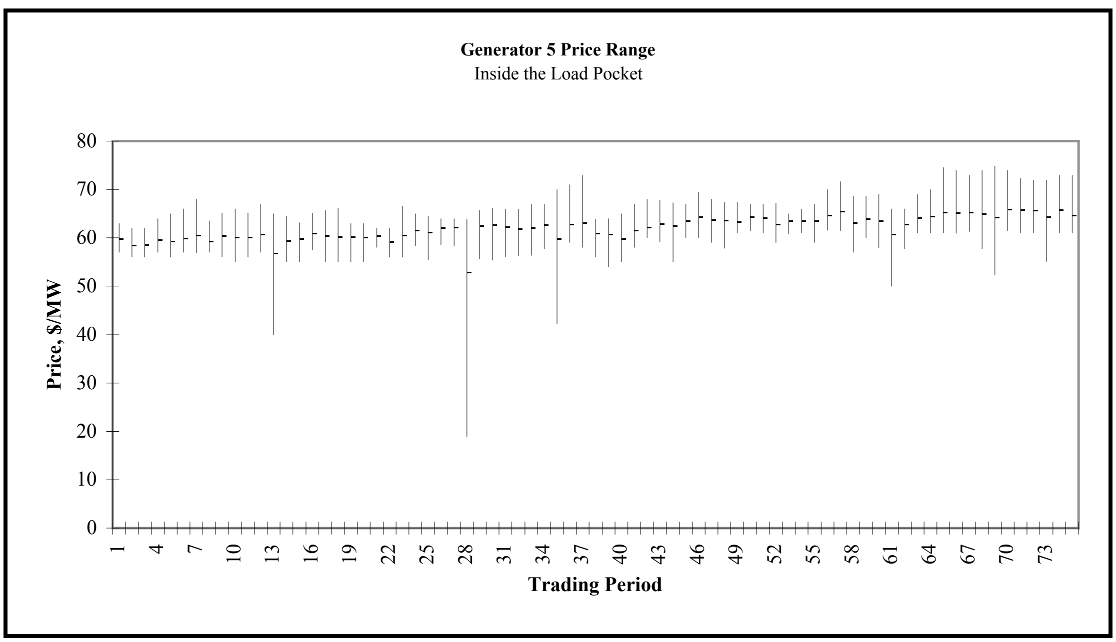


Figure 3-7: Generator 5 Price Ranges (Undergraduates)

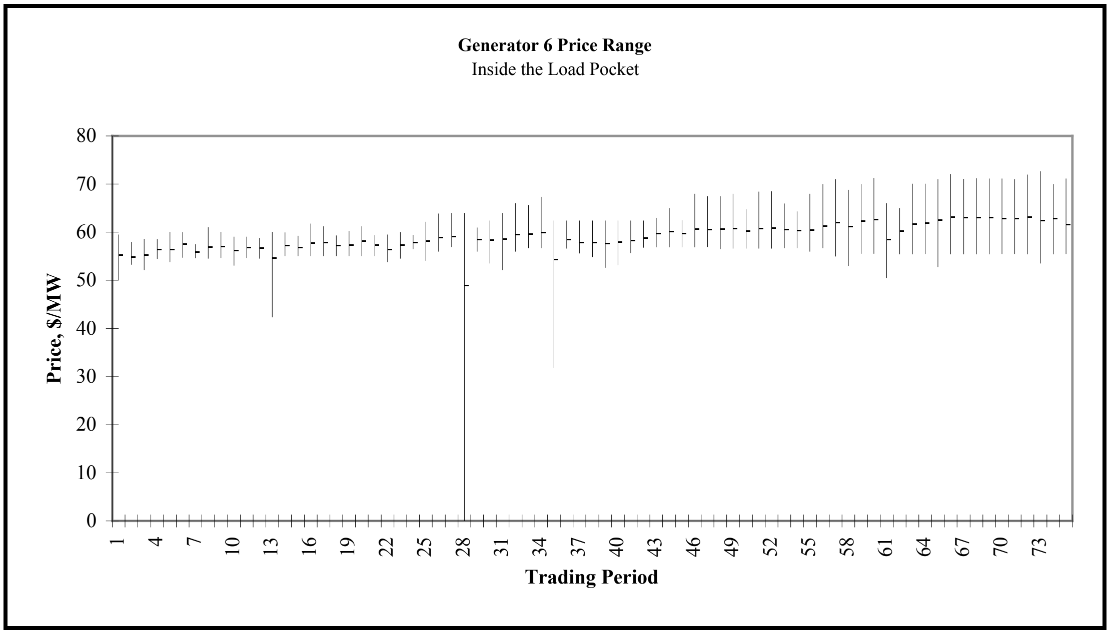


Figure 3-8: Generator 6 Price Ranges (Undergraduates)

3.4 Conclusions on Market Power

Transmission constraints have an important effect upon the intensity of competition within a market. These constraints afford a geographical advantage to some generators over others that can in some cases be entirely unaffected to the underlying differences in cost. In seventy-five periods, relatively inexperienced subjects with little or no knowledge of power markets and power grid operations were able to secure rent from favorable positions within the network. This should be an alarming conclusion, despite the simplicity of the auction and experiment. In summer periods with frequently congested markets it is reasonable to conclude that professional power marketers will become acclimatized to much more complicated markets and be able to secure congestion rents.

Market power is created not only by the transport limits on a specific transmission link but also by the ability to ensure that the link operates at its maximum capacity when required. This can be thought at a type of "cascading" market power. In Experiment I, a generator inside the load pocket is able to secure direct benefits from the reduction in competition and reducing its production to create a network externality that ensures other producers can not supply at a lower cost into the load pocket. In such constrained cases, the generators inside the load pocket are not perfect substitutes. In addition to competition with generators outside the load pocket being curtailed, competition inside the load pocket is also reduced. In the first experiment this externality concerned optimal power flow in the network, and in the second experiment the externality concerned the local voltage support provided by the load pocket generators. It would be incorrect to model market power, therefore, only in the context of reduced competition in supply of real energy. This illustrates why it is important to use a full AC network to test the performance of electricity markets.

The experiments highlight the importance of maintaining nodal pricing within the network. Some markets implement zonal pricing, Norway and California being two examples. The statistical analysis has shown that a single zonal price outside of the load pocket is not a bad representation of the nodal prices within that zone. The picture is very different inside the load pocket. In every single case the null hypothesis that the price for generator 5 and 6 could be represented by a single grand average was rejected in both experiments. Indeed in both experiments a price leader emerged. This was generator 6 in the first experiment and generator 5 in the second experiment. A single average price would not correctly reflect the full cost of resources used inside the load pocket. In such circumstances, a zonal price would lose valuable information about the effects of the constraints in the network.

4. Experiment B: Self Commitment of Generators

4.1 Introduction

Electric supply systems that serve a population typically experience repeating cycles of demand because of the nature of human activity. Demand for power is highest during the day and evening and lower at night. Electricity is not practicably storable, and if outages are to be avoided, sufficient supply must exist at all times to meet demand. In any power grid there will be a heterogeneous portfolio of generating assets. Large "baseload" plants typically have very small marginal costs of operation but are cumbersome to start-up and shut down, incurring significant costs in doing so. At the other end of the spectrum, "peaking" plants are quick to fire up or shut down but involve much greater marginal costs of operation. In between lie a variety of "shoulder" plants which serve load at intermediate cost and have moderate flexibility. Depending on the size of the generating portfolio, most if not all of the generators will be called upon to serve load in peak periods. It is not cost-efficient to simply commit sufficient units to the system to meet maximum load and have all units operate continuously. It is less costly to turn off some of the more expensive units when their capacity is superfluous. However, turning off a unit will result in start-up costs when the unit generates again and the reduction in variable costs in one period must be evaluated against an increase in lump sum costs in the next period. The underlying aim of this process is to find the optimal generation pattern for each generator connected to the power grid that minimizes total system operating costs over a specified time period.

Under regulation, unitcommitment and dispatch were traditionally managed through a centralized unit commitment and dispatch algorithm with perfect information about generator and network costs and operating constraints. This was possible because regionally vertical integrated monopolies provided information about the grid and all generators in a region. Wood and Wollenberg (1984) identify three different approaches to solving the unit commitment problem: priority list schemes, dynamic programming and lagrangian relaxation techniques. Priority list schemes produce a rank ordering of generators at a specific level of demand, say peak load. As demand drops, generators are dropped in order of their ranking on the list (subject to a set of conditions, such as meeting ramping constraints or minimizing total costs including start-up costs). The procedure continues until just enough supply has been dropped to meet load. A dynamic programming approach identifies a series of commitment and dispatch decisions that minimize the present value of production costs to meeting a forecasted pattern of load. A common approach is to minimize an objective cost function by varying the unit commitment decision for each unit in each period. An algorithm compares all the different possible permutations for the unit commitment decision. When run backwards, the optimal solution for the last period is found. With this information, the optimal solution in the penultimate period conditional on the last period solution is found. The process repeats until it reaches the current period. Start-up costs are often a function of the time a generator has been de-committed, consequently a forward dynamic programming approach may be appropriate since the commitment history of each unit can be included in the algorithm (Wood and Wollenberg, 1984). The lagrangian relaxation procedure, illustrated by Bertsekas *et al.* (1983), Bohn, *et al.* (1984) and Schweppe *et al.*, (1988) seeks to find a set of prices that induce the optimal commitment of all resources. This is an iterative process that is not guaranteed to find an optimal solution. However, Bertsekas found that the dual approach produced solutions close to those achieved by the primal (dynamic programming) approach, and the gap between the two alternative solutions decreased as the system size increased.

The supposed advantage to centralized unit commitment with perfect information is that a benevolent system administrator can find the least cost solution. There is no guarantee that this socially optimal solution is the profit maximizing solution for producers. In a deregulated market where profit is the primary incentive for owners of generating assets, centralized unit commitment might be exploited by the divergent interests of consumers and producers. In spite of this, many deregulated markets have continued to use centralized unit commitment.

Despite the attention that unit commitment has received, no single approach has emerged as the best way to determine the optimum solution. Indeed current approaches often employ unsatisfactory linear approximations to non-convex, non-linear problems (see Murilloo-Sanchez and Thomas, 2000 for a detailed discussion). To compound matters, Johnson, *et al.* (1996) found that the objective function can have a "flat bottom". For very slight variations in total system cost, there may be many near-optimal solutions. Despite the small changes in cost, the changes in unit commitment schedules can greatly affect the profitability of individual generators (particularly the marginal units). This may be of little importance to a regulated utility company with a portfolio of assets. Since revenues accrue to the same holding company, changes in the origin of revenues may have little overall effect. In a sense, profits and losses can be shared among all generators. As part of deregulation, utility companies have been forced to divest much of their generating capacity. Ownership patterns have changed. Variations in unit commitment schedules can have a dramatic effect, therefore, on profitability for owners of single generators. In a deregulated system, the unit commitment decision must be perceived as equitable. Unfortunately, the flat form of the cost curve makes it difficult to justify one solution over another in economic terms.

There are two contrasting forms of commitment and scheduling procedures used in the industry today. Firstly, generators are able to self-schedule generation through bilateral transactions to supply power for a period specified in a contract. Alternatively, power producers can submit price/quantity offer curves to a system operator/power exchange that are used to allocate load among generators. McAfee and McMillan (1987) define an auction to be a market institution with an explicit set of rules that is used to determine the allocation of a resource and its price depending upon the offers and bids of the participants in the market. The role of the system operator becomes that of the auctioneer; supervising the rules and adjusting the outcome to satisfy physical network constraints. In some markets, such as California, the two processes exist side by side, with a power exchange and a balancing market. In England and Wales, however, generators have been forced, until recently, to submit all but a small proportion of capacity into an auction-based market (Wolak. and Patrick [1997], Wolak [1997]).

The most common structure for electricity auctions are variations on the first-price multiple unit sealed-offer auction. In this auction, generators submit offer curves for their capacity that represent the minimum price at which they would be willing to operate generating capacity. The system operator implements a smart market that corrects for network constraints while calculating prices and allocations of load that maximize the gains from exchange. The auction outcome usually determines dispatch on an hourly or half-hourly basis for one trading period ahead on a rolling basis, or for a day ahead with all periods being determined simultaneously. Some form of balancing market is used in the latter case to ensure that supply equals demand in all periods

Wilson (1998) believes the characteristics of an offer are critical. Johnson and Svoboda (1997) outline three different ways in which a power exchange or power pool could operate an auction to determine the dispatch schedule. The auction rules might require generators to submit the following information:

- Start-up costs and a price/quantity curve with minimum up/down time and ramping constraints.
- Simple price/quantity curve with minimum up/down time and ramping constraints.
- Simple price/quantity curve with no inter-temporal operational constraints.

In the original England and Wales Power Pool, generators participated in a day-ahead energy market to solve the unit commitment problem for each of 48 half-hourly periods for the following day (Wolak, 1997). Generators are allowed to submit up to 3 offer increments per generating unit. In addition to the price/quantity offer schedule, the generators inform the National Grid Company (the owner of the transmission network) of the unit's start-up cost, unit availability for that period, the price of providing reserve capacity, the generators state of readiness and the price at which the generator would be willing to exceed declared availability. The National Grid Company then conducts a merit-order dispatch subject to transmission constraints, plant characteristics and system stability. This produces system marginal prices to which is added (to encourage long-term investment) a capacity payment based on the value of avoiding an interruption of load, and an UPLIFT charge which is used to pay for ancillary services and transmission services. Wolak and Patrick (1997) suggest that some of the gaming present in the England and Wales market is a result of the ability of the major producers to manipulate the rules and the derived parameters (such as capacity payments). Nevertheless, some major markets in the USA have emulated the UK approach. The UK government will alter the market in the autumn of 2000 to resemble the Californian system, abolishing the mandatory pool, permitting bilateral transactions and encouraging a voluntary power exchange (Office of Gas and Electricity Markets, 1999). A major reason behind this has been frustration with the centralized pool's ability to limit the market power of the largest two companies.

The markets in the northeastern states (New England, Pennsylvania, New Jersey, and Maryland [PJM], and New York) have adopted a similar approach to the England and Wales model. Generators typically submit to the ISO a day-ahead, price quantity schedule for dispatchable loads. In addition to the schedules, the generators are required to submit a variety of information on minimum up and down times, hot and cold start-up times, hot to cold transition time, ramping constraints, input levels during each stage of start-up and availability of ten-minute and thirty-minute spinning reserves. The ISO then conducts an "optimum" dispatch to meet the forecasted pattern of load the following day.

The Californian market has a number of scheduling coordinators who are able to dispatch generators to meet load subject to maintaining system reliability that is managed by the California ISO. The most influential of the coordinators is the California Power Exchange which accounts for about 80% of all power traded (California Exchange, 1998). In this market, generators and loads submit price/quantity schedules to the power exchange (PX). The PX constructs an aggregate supply and demand curve and determines the regional dispatch schedule and the system marginal prices. These results are transmitted to generators. Generators are able to alter their offers in an hour-ahead market by submitting incremental and decremental offers which signify by how much a generator must be paid to increase sales or reduce sales. From these offers, the same process is followed and final dispatch schedules are determined. Portfolio offers are permissible in the energy market, allowing producers greater discretion as to how they commit and de-commit their own units to meet contracted aggregate obligations to supply electricity. In California, generators are also able to self-commit capacity through bilateral transactions outside of the auction market. These transactions are subject to the reliability limitations on the transmission network through the operation of the incremental/decremental market.

The National Electricity Market in Australia, which encompasses the Australian Capital Territory, New South Wales, Queensland, South Australia and Victoria, operates a real-time five-minute spot market. From this five-minute market a half-hourly spot price is calculated. Each day, every generator provides NEMCO (the ISO) a dispatch offer. This offer specifies the minimum level of dispatch for the generator, known as the self-dispatch level, plus prices and corresponding increments of generating capacity above the self-dispatch level for each half hour of the next day. In the Australian market, generators manage both their own commitment and dispatch. NEMCO then allocates load across the generators in merit order of offers subject to ensuring system reliability [NEMCO, 1998]. In the real time market, generators are allowed to change their quantities offered, but not their prices, for each offer increment. Unlike the centralized markets, no other information is required from generators. The generators must allow for their own operating constraints and ensure that their offers do not compromise them. In contrast to California, Australia allows generators to self-commit only by offering sufficiently low or negative prices on their must-run capacity. In this sense, generators must be willing to pay in order to avoid being shut off by the auction.

Market-based auctions need be able to produce solutions that are close to the optimal solution. Johnson and Svoboda (1997) found in power markets that marginal cost offers did not produce a Nash equilibrium. If the generators were able to self-commit and generate at prevailing prices, all but the base-load generators would change their operations to increase their profitability. This would imply that generators ordinarily cycling would seek a schedule in which they operated continuously. Generators can, therefore, increase their profits by submitting price/offer curves that do not accurately reveal true costs. This distorts prices from their competitive levels and can lead to an inefficient commitment of units. This tendency is exacerbated when the information provided to the auction is more complicated, when, for example, unrealistic minimum run times are submitted.

Oren and Elmaghraby (1999) further developed the idea that one period markets cannot solve unit commitment effectively. They conclude that start-up costs produce important intertemporal dependencies. There is an incentive for generators to offer below marginal cost to ensure dispatch in one period because the potential losses incurred are more than offset by the reduction in start-up costs incurred in the future. As a result, they show that expensive generators can displace cheaper generators in the unit commitment schedule. The outcome of this non-optimal behavior is that some generators are able to increase their own profitability at the expense of system-wide efficiency.

Much depends on the response of the incumbent generators. If the incumbent generators do not anticipate the actions of the cycling generators then self commitment will be inefficient. Since power auctions repeat on a daily or hourly basis, it is realistic to conclude that incumbent generators would notice a change in their commitment patterns, particularly if it changes their profitability, and will change their own strategy. Start-up costs tend to be inversely proportional to marginal costs. Incumbent generators will only modify their offers if profits are reduced by the change in their schedule and if corrective strategies cost less than the original loss in profits. If baseload plants have large start-up costs they will have stronger incentives to ensure continual commitment than peaking plants. Likewise, shoulder plants will have a stronger incentive to discount offers than peaking plants. If all types of plants discounted their offers in off-peak periods correctly, it seems that the correct generators would be committed in such a way that efficiency would be comparable to the optimal solution in a regulated system. This proposition is the focus of a set of experiments conducted to assess the efficiency of market-based self commitment.

Some experimental work has already considered the unit commitment problem indirectly. Plott found that high demand periods created pressure on low demand periods by attracting extra suppliers, creating excess supply and increasing the speed of convergence to equilibrium (Plott, 1997). Backerman *et al.* (1997a) found that the sealed offer auction produced high efficiency with prices close to equilibrium. They also showed that generators were vulnerable in contract negotiations as a result of must-run constraints. Importantly, they found that the must-run characteristic of some generating units caused stressful market conditions for generators in off-peak periods when generators faced penalties for operating below some fixed capacity. Offers were forced down, producing a much lower spot market price in off-peak periods.

4.2 The Design of the Experiments

A set of experiments was conducted to examine whether market-based self commitment could minimize the system-wide production cost of meeting an alternating high load and low load. The same underlying power grid used for both of the market power experiments was used again. For this experiment, however, all transmission constraints were relaxed. While transmission losses could affect market outcomes, an objective of experimental economics is to focus on a single feature. More compicated experiments involving more than one feature could be run at a later date. In high demand periods, system wide demand was approximately 200 MW. In low demand periods, demand was approximately 100 MW. This is a stylized representation of a demand pattern, but it still forces participants to consider the unit commitment problem in a manner consistent with real markets.

Six undergraduate, one graduate and one utility executive sessions were conducted. In each session, six generators competed for an allocation of load by submitting price offers for each of three blocks of capacity. An auction was held before each trading period, and the results were shown and the market cleared before the next trading period. This is equivalent to a real time auction rather than a day-ahead auction. The first trading period of each session was a low demand period (it is assumed that all generators operated in the previous period). Each subsequent trading period alternated between high and low demands. The experiment was equally divided, therefore, between peak and off-peak periods.

Demand in the peak periods was sufficient to ensure that, with marginal cost offers, all generators would sell some capacity and make sufficient profit to provide salient rewards for continued rational performance in the experiment. Participants were not permitted to exit the experiment they could in the utility industry. In order to keep subjects motivated, some profits in the high demand periods were necessary. In the low demand periods, however, demand was low enough that only a subset of the generators would be required to meet load. Those generators operating would mostly be selling close to their minimum operating constraint (the first block of capacity).

Generators who did not sell at least their first block of capacity were shut out of the low demand periods and incurred start-up costs in the next period in which they were successful in selling capacity (usually the next high demand period). These generators needed to decide which a strategy should be pursued to increase profits over a cycle of high and low demand periods. For example, could a generator offer below cost in low demand periods and incur fewer losses than paying start-up costs in the next high demand period? Generators operating in both the high and low demand periods needed to assess at what cost they would be willing to defend this position before being de-committed. Was it rational to maintain continuous dispatch or could aggregate profits over the two period cycle be increased by not operating in the low demand period?

Table 4-1 shows the block capacities and variable operating costs for each of the six generators in the experiment. The relative block sizes and variable costs were designed to provide a comparison of incentives between the different types of generating assets in the real market. Two of the six generators can be considered "baseload," with low operating costs but significant start-up costs. Two of the six generators can be thought of as "shoulder" plants with intermediate operating and start-up costs. The final two generators are "peaking" units with high operating costs but low start-up costs. For the purposes of this experiment, the minimum up and down time for each generator was one period.

Table 4-1: Generator Costs and Variable Capacities

	Capacities and Variable Costs						*Start-Up Cost ($)*
Generator	Block 1		Block 2		Block 3		
	MW	500	MW	50	MW	Cost ($)	
1 – Peaking	10	150	25	50	25	35	50
2 – Peaking	10	150	25	500	25	35	50
3 – Base-Load	20	500	30	150	10	40	500
4 – Mid-Level	20	20	20	150	20	40	150
5 – Mid-Level	20	20	20	500	20	40	150
6 – Base-load	20	15	30	15	10	40	500

Table 4-1 shows the start-up costs by generator and their designation. As can be seen there is an inverse relationship between the variable and start-up costs. The next step is to determine the optimal operating schedule of the generators in both the high and low demand periods. A Nash equilibrium will again be difficult to find because of the non-convexity of the objective function with respect to the binary nature of the unit commitment decision, either on or off, and the large number of physical and operating constraints implied in the power grid. Intuitively, it is possible to see that low period demand can be entirely satisfied by a combination of both baseload plants. With the other four generators turned off for the low demand period, a total of $400 in start-up costs will be incurred in the next high demand period when it is efficient for all generators to operate. This, however, is not an optimum operating point. Reducing the capacity sold by the baseload plants and bringing on both of the shoulder plants at minimum capacity saves $300 in start-up costs. The extra operating costs incurred are far less than this amount, and so there is a net benefit to the system. Using the peaking generators in low demand periods, however, would not be cost effective.

In order to confirm this intuition, a forward dynamic programming algorithm was used to determine the optimal dispatch for each generator given known costs and constraints[7]. A MATLAB based package evaluated all commitment possibilities for each demand period. This algorithm produced the optimum commitment and dispatch schedules shown in Table 4.2. The only generator operating above its minimum capacity in the low load period is baseload generator 6. Four

[7] The authors thank Dr. Carlos Murillo-Sanchez, Department of Electrical Engineering, Cornell University for the use of his unit commitment software.

generators operate continuously, and the two peaking units cycle on and off. The total operating cost for two periods is $6302, which includes only $100 for startup.

Table 4-2: Centralized Unit Commitment and Cost Based Dispatch Schedule

Generator	*Off Peak, 100 MW*	*Peak Demand, 200MW*	*Start-Up Costs, $*	*Total Operating Cost, $*
1 – Peaking	0	12.32	50	349.60
2 – Peaking	0	22.93	50	667.90
3 – Baseload	20	50	0	1260
4 – Shoulder	20	32.82	0	1184.50
5 – Shoulder	20	33.74	0	1212.40
6 – Baseload	40.5	50	0	1357.50
TOTAL	100.5	201.81	100	6031.90

Generators should be willing to submit offers in the low load period that will leave them indifferent between cycling on and off or operating in both the high and the low demand periods. The offer for the first block of capacity determines whether a generator will operate or not, and it is critical in any strategy. The following low demand period offer strategy will leave a generator indifferent between operating and not operating in a low demand period.

On the first block: *Offer price = marginal cost – (start-up cost/size of first block)*

On higher blocks: *Offer price = marginal cost*

In high demand periods, generators which were shut off in the low demand period will not wish to operate unless they can cover operating and start-up costs. In other words, the price in the high demand period must satisfy the following condition:

On first block: *Offer price ≥ marginal cost + (start-up cost/capacity offered)*

The lump sum start-up cost is included in the offer because it is effectively a variable cost. If the generator decides not to operate in the high demand period, it will not incur that cost. On the other hand, losses incurred by operating in the low demand period should not affect the offer in the high demand period because they constitute a fixed cost that has already been paid. To offer at a price above marginal cost would jeopardize profits from selling extra units that could offset the losses. If a profit cannot be made using this strategy, the generator should consider changing to an alternating on and off strategy.

Since the costs are represented by step functions, some flexibility in pricing is possible. The commitment and dispatch outcome may be unchanged so long as the offer is epsilon less than the next highest offer, where epsilon is the lowest permitted offer increment. Generators may be able to secure commitment with higher offers, but this will depend critically upon the potential for exploiting market power in the market. Table 4.3 below shows the optimal competitive offers by generator in the low and high demand periods. This represents the optimal unit commitment where the peaking generators 1 and 2 are assumed to cycle on and off.

Table 4-3: Lowest Rational Offers for Self Commitment

Generator	*Block 1*		*Block 2*		*Block 3*	
	Off Peak	Peak	Off Peak	Peak	Off Peak	Peak

1 - Peaking	18	28	30	30	35	35
2 - Peaking	18	28	30	30	35	35
3 -Baseload	-7	18	18	18	40	40
4 - Shoulder	12.5	20	30	30	40	40
5 - Shoulder	12.5	20	30	30	40	40
6 - Baseload	-10	15	15	15	40	40

While the peaking plants do have an incentive to offer below cost in the low load period, this is also true for the shoulder and the baseload plants. Indeed the higher start-up costs allow the shoulder and baseload plants to outbid the peaking plants. The offer schedules shown in Table 4-3 would result in the same commitment and dispatch schedule shown in Table 4-2.

Since the goal of unit commitment and dispatch is to minimize production costs over high and low load cycle, an appropriate measure of efficiency is important to assess market-based results. Efficiency is measured as an aggregate of the high and low demand period costs and will be defined as:

$$Percentage\ Efficiency = \frac{100\ x\ Minimum\ \cos t}{Actual\ \cos t}$$

Bernard (1999) notes that efficiency measures can be misleading since they are dependent on the design of the experiment, the cost and capacity parameters and the number of participants in the market. Consequently, it is helpful to establish a target range for efficiency. Efficiency should be higher than the level achieved using marginal cost offers (a transparent but sub-optimal process) and cannot be more than centralized unit commitment (optimal at 100%). This notion of efficiency will be a relative rather than an absolute measure. Marginal cost offers produce an efficiency of 96.45%. As each of the sessions progressed and participants learn how the market works, one would expect efficiency to increase.

4-3. The Results of the Experiments

Figure 4-1 shows the time path of efficiency for the undergraduate sessions (an average of all six), the graduate student session and the utility executive session. As mentioned earlier, the undergraduate and utility executive sessions lasted 60 periods (split evenly between high and low demand periods) or 30 cycles, but the graduate session lasted only 40 periods or 20 cycles. The results clearly show that as the experiments progressed efficiencies converged on 100% and ended up higher than the efficiency achieved by marginal cost offers. The variability in results in the earlier rounds of the experiments can be explained by inexperience with the auction format. It also demonstrates that when offers produced out-of-merit dispatch, efficiencies can be relatively low.

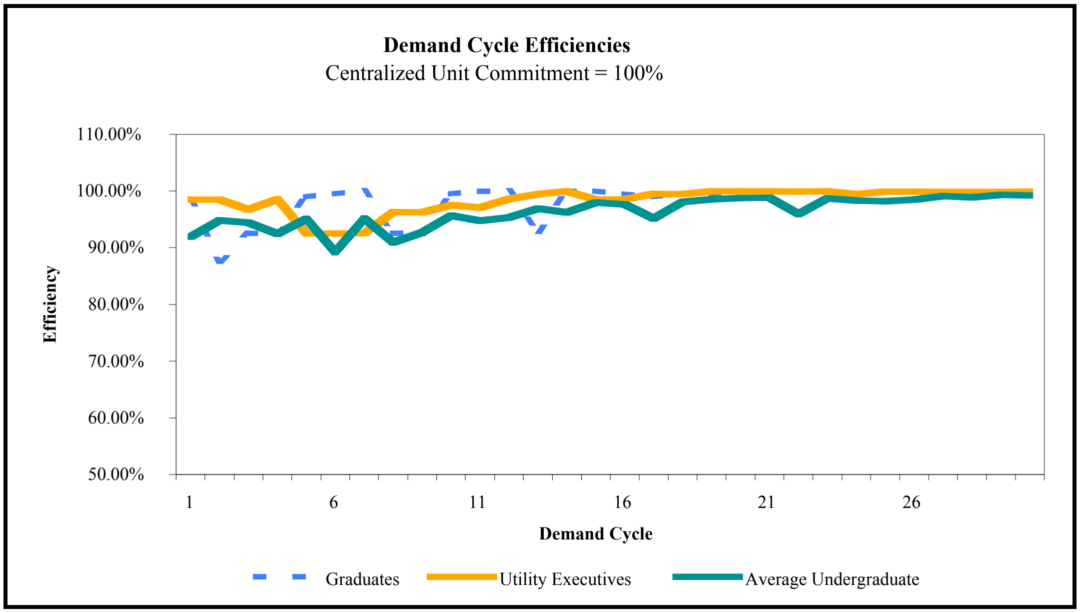


Figure 4-1: Market Efficiencies

Table 4-4 provides the descriptive statistics for the efficiencies during the last ten demand cycles. The pooling of undergraduate results can be justified by the homogenous nature of the undergraduate subjects used in the experiment. An F-Test for testing the hypothesis that the individual means of each undergraduate session are equal supported the null hypothesis. Consequently, the undergraduate sessions were pooled and an aggregate mean was calculated.

Table 4-4: Market Efficiencies

Session	*Average Undergrad*	*Grad.*	*Utility Exec.*
Mean	98.49%	99.02%	99.85%
Standard Deviation	0.24%	2.18%	0.16%
Minimum	82.06%	92.89%	99.42%
Maximum	99.94%	100%	99.99%
Observations	60	10	10
95% Confidence Interval	98.01% - 98.97%	94.09% - 103.95%-	99.53% - 100.17%

Table 4.4 shows that all of the sessions achieved efficiencies in the last ten cycles that were extremely close to 100%. The utility executives achieved the highest average efficiency with the smallest standard deviation. The graduate session achieved the highest observed efficiency in any cycle, but had a greater variance in results than the utility executives. This probably resulted from the fewer number of cycles played by these subjects. The undergraduate students, who were the least experienced subjects, achieved a lower mean efficiency, but it was closer to 100% than to the efficiency of 96.45% achieved by marginal cost offers. Since it is not possible to achieve efficiency greater than 100%, all the error is one-sided. It is not possible, therefore, to conduct standard hypothesis tests because the error is not distributed normally. The confidence intervals show that all three average efficiencies are significantly higher than marginal cost efficiencies. The graduates and the utility executives produced efficiencies that are not significantly different from 100%. The market appears to produce cost-efficient outcomes when generators are allowed to self-commit units.

Underlying the results in Table 4-4 are the offer strategies of the generators and the resulting commitment schedules. Figure 4.2 shows the observed offers in the low demand periods for each of the generators (averaged for all of the undergraduate sessions). In order to assess the offers, each chart also shows the marginal cost offer and the actual offer. The results show that the peaking generators were very quick to learn to offer below marginal cost on their first block, and converged during the experiment to the lowest optimum offer of $18/MW. This has a cascading effect on the other generators. The shoulder plants learned to offer below marginal cost and converged to the lowest optimum offer of $12.50/MW at a slower rate than the peaking plants. The baseload plants were the slowest to lower their offers, though by the end of the experiment, each baseload generator was offering below marginal cost. In this auction, if the other generators submitted offers at the optimum levels, the baseload generators would only need to submit offers below $12.50/MW to guarantee dispatch. However, it was surprising that the two baseload generators did not use a more aggressive strategy by making lower offers to reduce the chance of being shut off.

Figure 4-2: First Block Offers By Generators

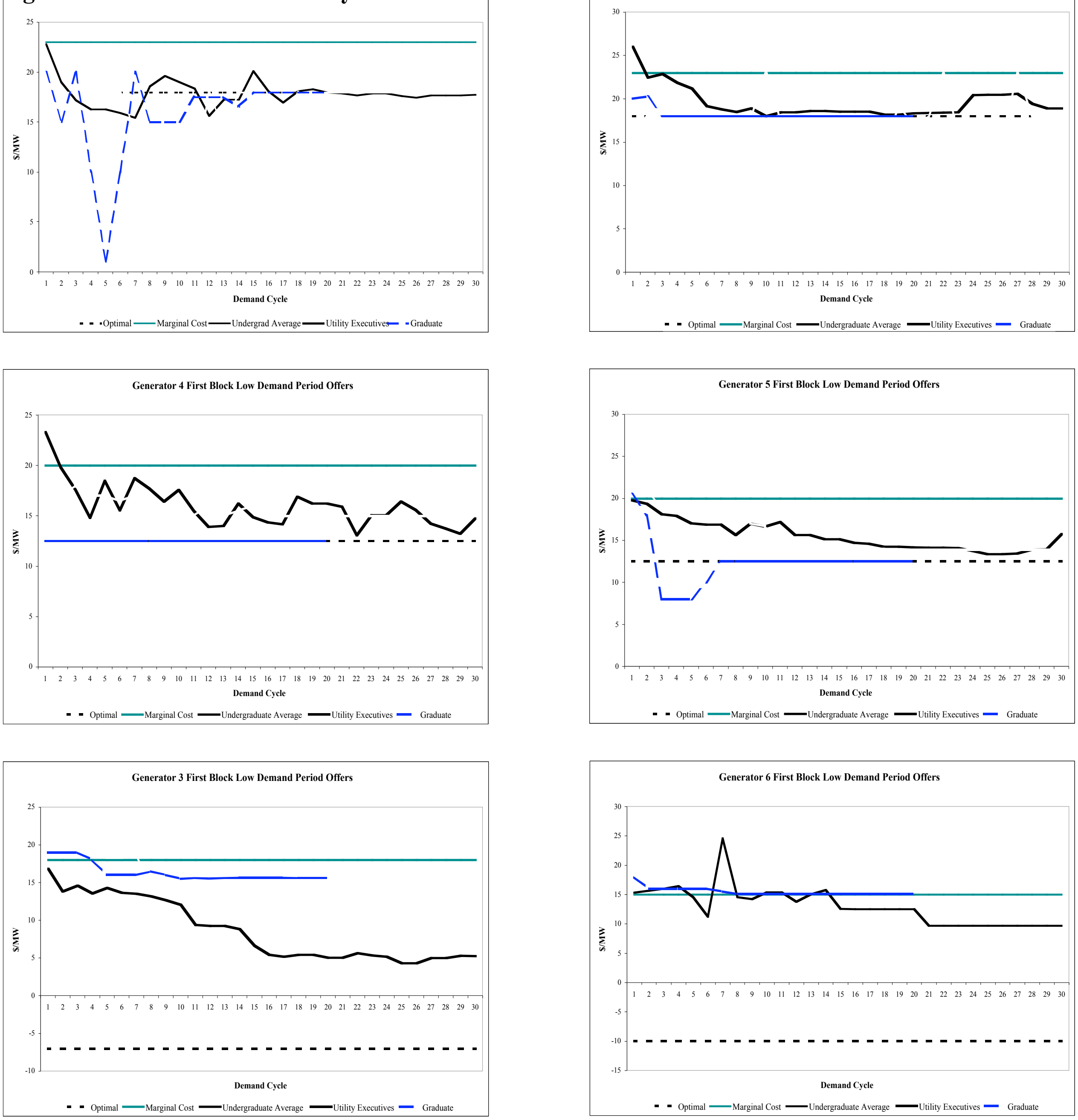


Table 4.5 provides a statistical comparison of the average first block offers for each of the generators across the last ten low demand periods in the experiments. Every generator (with the exception of generator 6 in the graduate session) offered significantly below marginal cost.

Table 4-5: First Block Offer Averages, Last Ten Low Demand Periods

Generator	*Statistic*	*Undergraduates*	*Graduates*	*Executives*
1	Mean	17.69	17.7	18.1
Peaking	Standard Error	0.04	0.15	0.89
	95% Confidence Interval	17.77-17.59	17.89-17.21	20.11-16.09
	Includes MC?*	No	No	No
2	Mean	19.45	18.00	18.00
Peaking	Standard Error	0.30	0	0
	95% Confidence Interval	20.45-18.85	18.00-18.00	18.00-18.00
	Includes MC?*	No	No	No
3	Mean	5.05	15.60	12.90
Baseload	Standard Error	0.13	0.01	0.03
	95% Confidence Interval	5.31-4.79	15.62-15.58	12.97-12.83
	Includes MC?*	No	No	No
4	Mean	14.715	12.50	12.50
Shoulder	Standard Error	0.41	0	0
	95% Confidence Interval	15.54-13.91	12.50-12.50	12.50-12.50
	Includes MC?*	No	No	No
5	Mean	14.00	12.5	13.90
Shoulder	Standard Error	0.22	0	0
	95% Confidence Interval	14.44-13.56	12.50-12.50	13.90-13.90
	Includes MC?*	No	No	No
6	Mean	7.63	15.05	1.00
Baseload	Standard Error	0.03	0.00	0.00
	95% Confidence Interval	7.69-4.79	15.05-15.05	1.00-1.00
	Includes MC?*	No	No (above)	No

* Null hypothesis, mean=marginal cost.

The first block information does not, however, complete the picture. Another 20 MW of second block capacity is required from baseload generator 6 to meet load optimally. Since generator 6 has the lowest marginal costs on its second block, it should always be dispatched. However, if offers are above marginal cost, this block comes into competition with the second block of generator 3, the other baseload plant, and the first blocks of the peaking plants. Table 4.6 shows the mean offers for the second blocks of baseload generators 3 and 6. As can be seen, offers were on average slightly above marginal cost. The utility executive with generator 6 was the only individual to submit marginal cost offers. If the peaking plants offered below their lowest optimum, a peaking unit could have been dispatched at the expense of the second block of generator 6's capacity. If the market price was higher than \$18/MW, then profits for the peaking unit would increase, but the dispatch would be inefficient.

Table 4-6: Generator 3 and 6, Second Block Offers

Generator	*Statistic*	*Undergraduates*	*Graduates*	*Executives*
3	Mean	20.34	18.03	18.5
Baseload	Standard Error	0.14	0.02	0
	95% Confidence Interval	20-62-20.06	18.07-18.01	18.5-18.5
	Includes MC?*	No	No	No
6	Mean	16.11	17.32	15
Baseload	Standard Error	0.34	0.92	0
	95% Confidence Interval	16.79-15.43	19.40-15.24	15.00-15.00
	Includes MC?*	No	No	Yes

* Null hypothesis, mean=marginal cost.

In summary, the offers observed on the crucial first block of capacity in the low load periods were generally below marginal cost levels. Each of the generators appears to have comprehended the effect of start-up costs on profits and the required compensatory offer strategies. The results from the high demand periods do not provide highly useful information. Behavior was less variable in the peak periods than the off-peak periods. The second blocks of the two peaking plants, 1 and 2, and the shoulder plants, 4 and 5, were correctly competing to set the system marginal price. One would expect the generators to find it difficult to reach a stable equilibrium. Nonetheless, in the last ten demand periods generators did settle on a fixed pattern of offers to a greater extent than seen in the low-load periods.

The evidence from the experiment suggests that a simple market-based commitment auction can achieve a high degree of efficiency and that generators, on average, supply offers below marginal cost in the low load periods to avoid start-up costs. The next step is to determine whether merit order within the dispatch schedule was maintained, and if not, at what cost to system efficiency. There are two important measures of performance. First, does the auction lead to the optimal unit commitment? Second, is the allocation of generation among committed generators correct? With this information, it will be possible to better understand the efficiency information and make qualitative conclusions about the performance of the auction process.

If unit commitment and the dispatch decision had been determined by centralized techniques, generators 1 and 2 would not have operated in the low load period. Table 4.7 shows the optimum allocation of load among generators during low and high load periods, and the corresponding observed allocations. For the optimum allocation in the load periods, generator 6 has the largest share of load with the balance being shared equally among the baseload, generator 3, and the shoulder plants, generators 4 and 5. Using the average observed allocation of generators in the last ten low load periods for all eight sessions in the experiment shows that the peaking generators 1 and 2 sold more capacity than the optimum levels.

Table 4-7: Allocation of Load Among Generators

Generator	*Low Demand (100MW)*		*High Demand (200MW)*	
	Expected	**Actual**	**Expected**	**Actual**
1 – Peaking	0%	4%	6%	11%
2 – Peaking	0%	3%	11%	11%
3 – Baseload	20%	23%	25%	24%
4 – Shoulder	20%	17%	16%	16%
5 – Shoulder	20%	19%	17%	13%
6 – Baseload	40%	34%	25%	25%

Given the indivisible nature of each generator's first block, this means that generators 1 and 2 were able to sell at least 10MW of capacity in some periods. The load allocated to the peaking plants is primarily at the expense of generator 6. Since the shoulder plants were allocated less than 20% of load on average, this implies that these generators were shut down in some periods. It is interesting to note that generator 3 had a higher allocation than the optimum level. Generator 3 was able to sell some of its second block in place of the second block of generator 6.

The primary interest in high load periods is the allocation of load among generators rather than unit commitment because typically all generators will operate. Table 4-7 shows the optimum allocation of load among generators in high load periods with demand approximately 200 MW. The observed average allocation of load to each generator in the last ten high load periods show that the baseload generators 3 and 6 operate within 1% of the optimum levels. Peaking generator 1 generates more than the optimum at the expense of shoulder generator 5. The main competition for load correctly took place in a very flat section of the industry supply curve where there were several competing generators with similar costs. The baseload generators, which provide the lowest cost capacity in their first and second blocks were both dispatched optimally in all sessions. All generators were committed all of the time implying, as anticipated, unit commitment was not an issue during high load periods.

4.4 Conclusions on Self Commitment

The fact that generators quickly learn how to deal with start-up costs is clear evidence to support the analysis of Johnson and Svoboda (1997). By offering below marginal cost in low load periods, generators are implicitly stating that they can achieve a better commitment decision than using marginal cost offers. Cost efficiencies in the market are high and converge on the optimal solution determined by centralized unit commitment and dispatch. With more experience, it is likely the observed efficiencies would have got closer to 100%. Further supporting evidence for this conclusion is that the utility executives got the highest efficiencies. Since this was a relatively complicated market for students to understand, more experience would almost certainly payoff for them. In terms of minimizing the production cost of electricity, the auction produced excellent results.

The limitations of the market are also apparent in the results from this experiment. Markets rely on clear and strong incentives to guide participants towards an optimal equilibrium. A complication with power markets is that in some cases the optimal solution is difficult to discern from many near optimal solutions. If centralized unit commitment using best computation techniques has difficulty finding the optimal solution, there is no reason to expect that the market will do better. The difference in costs between the optimal commitment and observed sub-optimal commitments were small.

Although economic incentives were strong enough to lower the offers on the first blocks of capacity, they were not strong enough to complete the job. The shoulder plants and baseload plants did not consistently lower offers enough to shut out competition from peaking plants. Although efficiency was high, different unit commitment and dispatch results were observed. Does this mean the market has failed? From an experimental design perspective, subjects were more than sufficiently remunerated to ensure that their attention was focused on the experiment at hand. The performance of the market, rather, reflects the ambiguity of a situation with a large number of close-to-optimal solutions.

The importance of economic incentives is illustrated by the fact that peaking generators were more aggressive at lowering offers in the low load periods. The incentive to do this came from actually paying start-up costs. If baseload generators had been shut out of the market in some periods, they also would have learned the same lesson very quickly. Since baseload generators operated continuously and profits were positive in all periods, their reactions to losing market share in some periods were relatively mild.

Should a 1% loss in efficiency with self commitment be of concern to policy makers? This loss is a substantial waste of scarce resources, but in comparison to centralized unit commitment and dispatch the outcome may still be justifiable. Self commitment decentralizes the decision-making. If generators want to operate at prevailing prices, they can reduce their offers to achieve this. With few restrictions on the offers imposed, the generators can have few complaints about the fairness of the auction. However, fairness is an important criterion. Under centralized unit commitment solution algorithms are complicated and use approximations that may lead to unexpected and sub-optimal results. In these centralized markets, price/capacity offers are supplemented by information about start-up costs, minimum up and down times and ramping rates. By requiring this information, the auction becomes more vulnerable to exploitation. For example, Wilson (1998) and Wolak and Patrick (1997) have expressed concern that increasing complexity of the auction enhances the ability of participants to manipulate the outcome. In other words, there is no guarantee that centralized unit commitment in a deregulated market will achieve 100% efficiency.

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