Using Experiments to Inform the Privatization/Deregulation Movement in Electricity

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At the University of Arizona, electronic trading (now commonly known as e-commerce) in the experimental laboratory began in 1976 when Arlington Williams conducted the initial experiments testing the first electronic "double-auction" trading system, which he had programmed on the Plato operating system. The term "double auction" refers to the oral bid-ask sequential trading system used since the 19th century in stock and commodity trading on the organized exchanges. This system of trading has been used in economics experiments since the 1950s, and is extremely robust in yielding convergence to competitive equilibrium outcomes (Smith 1962, 1982a). Since information on what buyers are willing to pay, and sellers are willing to accept, is dispersed and strictly private in these experiments, the convergence results have been interpreted (Smith 1982b) as supporting F.A. Hayek's thesis "that the most significant fact about

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this (price) system is the economy of knowledge with which it operates, or how little the individual participants need to know in order to be able to take the right action" (Hayek 1945: 526–27).

As with all first efforts at automation, the software developed by Williams allowed double-auction trading experiments that previously had kept manual records of oral bids, asks and trades, to be computerized.[1] That is, it facilitated real-time public display of participant messages, recording of data, and greater experimental control of a process defined by preexisting technology. It did not modify that technology in fundamental ways. This event unleashed a discovery process commonplace in the history of institutional change: the joining of a new technology to an incumbent institution causes entirely new, heretofore unimaginable institutions to be created spontaneously, as individuals are motivated to initiate procedural changes in the light of the new technology. Electronic exchange made it possible to vastly reduce transactions cost—the time and search costs required to match buyers and sellers, to negotiate trades, including agreements to supply transportation and other support services. More subtly it enabled this matching to occur on vastly more complicated message spaces, and allowed optimization and other processing algorithms to be applied to messages, facilitating efficient trades among agents that had been too costly to be consummated with older technologies. Moreover, resource allocation problems thought to require hierarchical command and control forms of coordination, as in regulated pipeline and electric power networks, became easily susceptible to self-regulation by entirely new decentralized pricing and property right regimes. Coordination economies in complex networks could be achieved at low transactions cost by independent agents, with dispersed information, integrated by a computerized market mechanism. This realization then laid the basis for a new class of experiments in which the laboratory is used to test-bed proposed new market mechanisms to enable a better understanding of how such mechanisms might function in the field, and to create a demonstration and training tool for potential participants and practitioners who become part of the "proving" process. Of course, once adopted, this modification and proving process continues in light of field experience.

We provide a short history of the application of the conception of

[1]Williams (1980) reports comparisons of the oral and electronic auctions. He found that oral auctions converged more rapidly for inexperienced subjects, but for experienced subjects (one previous session) the two systems were indistinguishable.

smart computer assisted markets to the design of electricity markets here and abroad.

The Privatization/Deregulation Movement in Electricity

We use the term "privatization" to describe generically the process of reform of foreign government command forms of organization of the electric industry. In *all* cases major components of the industry have *not* had their ownership transferred from public to private entities. Reform has focused on the use of decentralized spot and futures markets to provide price signals to improve the short and longer term management of the industry. The term "deregulation" applies to electricity reform in the United States, where 50 state and one federal regulatory body have regulated an industry already predominantly owned privately, but *not* decentralized except through recent reforms in some regional transmission systems that are still very much in transition.

The Arizona Utility Study

In 1984 the Arizona Corporation Commission (ACC) contracted with the University of Arizona experimental economics group to study alternatives to rate-of-return regulation of the utilities, with particular emphasis on electric power. The study consisted of two parts: incentive regulation (Cox and Isaac 1986) and deregulation (Rassenti and Smith 1986; also see Block, et al., 1985). Only the second part will be discussed here since this was the study that led to a long and continuing research program, encouraged by the privatization/decentralization movement abroad, with applications first in New Zealand, then Australia, and most recently in the United States.

Recommendations

The deregulation portion of the study led to many detailed recommendations that can be briefly summarized in the following key points (see Rassenti and Smith 1986):

1. The energy (generation) and wires (transmission and distribution) businesses would be separated, with generator plants (gencos) spun off from parent integrated utilities through the issuance of separate ownership shares to form independent companies.
2. An economic dispatch center (EDC) would be formed that would operate a computerized spot auction market for deter-

mining prices and allocations based upon hourly location (node) specific offer price schedules submitted by gencos. The spot market would be constituted so as to facilitate and incentivize the eventual inclusion of demand side bidding by discos (distribution companies and any other commercial and industrial bulk or wholesale buyers). Thus, ultimately and ideally, prices would be determined in an hourly two-sided auction in which discos would submit location specific bids to buy energy delivered to their location just as gencos would submit offers to inject energy at their respective locations on the grid.

3. Discos and transcos (transmission companies) would not be protected by exclusive franchise permits, and would be subjected to the price discipline of potential, if not actual, entry.
4. Important functions of existing institutions would be preserved but operate through a computerized spot market bidding mechanism based on decentralized ownership of gencos.

By "existing institutions" we referred to optimization—historically, computerized dispatch based on the engineering cost characteristics of generators and the network of integrated utilities—joint ownership by utilities of shared transmission capacity, and power pooling rules for security (spinning) reserves. In the proposed competitive reorganization, optimization algorithms would not be applied to production and transmission "cost" as in the regulated, hierarchical, integrated utility, but to the offer supply schedules and bid demand schedules submitted to the computer-dispatch center. The algorithms would maximize the gains from exchange (rather than minimize engineering cost as under regulation) in response to the real-time decisions of all buyers and sellers in the wholesale market. This specification was motivated by the recognition that (1) supply cost is subjective and measured by the willingness to accept payment for energy produced on location, and (2) demand is subjective and measured by the willingness to pay for delivered energy, where both types of information express the particular *real-time circumstances* of individuals. Coordination was a consequence of a new form of property rights: (1) rules for processing messages generated by decentralized agents themselves empowered by rights to choose offers and bids; (2) contingency rules for accepting offers and bids based on their merit order (higher bids and lower offers have priority in the rank ordering of bids and of offers), but importantly *qualified* by technical and security constraints that are essential if each agent is to bear the *true opportunity cost* that the agent imposes on all others.

The term "property rights" as we shall use it, provides a guarantee allowing action within the guidelines defined by the right. Such guarantees are against arbitrary reprisal in that they restrict punitive strategies that can be levied against actions taken by the rights holder. Such guarantees provide only limited certainty of protection. Most specifically, property rights, as a guarantee allowing action, do not guarantee outcomes, since outcomes depend upon the property rights of others, and in electricity markets, as we shall see, upon global constraints affecting local outcomes that must be honored if the system is to be efficient, dynamically stable, and to incentivize the direction and level of capital investment.

Defining Competitively Ruled Property Rights to Unique "Monopolistic" Facilities

It was the ACC project that alerted us to the existence of "cotenancy contracts" for the joint ownership and operation of some large generation and transmission facilities. For us this was an illuminating empirical discovery, since this institution, that we modified with competitive property right rules, offered the potential to render the concept of natural monopoly null and void. Thus, suppose a city demand center can be adequately served by a unique physical facility such as a pipeline or transmission line. Under American-style regulation it is decreed that an exclusive franchise will be awarded to a single owner of the facility, whose price will be set so as to regulate the owner's rate of return on investment. Alternatively, in our proposed competitively ruled joint ownership property right regime it is decreed that (1) the facility must have two or more co-owners each having an agreed share of the rights to the capacity of the facility (In practice a common cotenancy contract rule is for each cotenant to receive capacity rights in proportion to his contribution to capital cost). Two additional competitive rules would allow (2) rights to be freely traded, leased or rented, and (3) new rights to be created by agreement to invest in capacity expansion by any subset of the co-owners, through unilateral action by any co-owner, or by outsiders if the existing owners resist expansion to meet increased demand. In historical practice cotenancy contracts had prohibited sale by individual rights holders without the consent of the other cotenants, and capacity expansion was allowed to occur only by joint agreement. The proposed new property rights structure creates multiple rights holders to compete in marketing downstream services utilizing the unique facility, and encourages new investment in response to increased demand. Subsequent to the ACC study, new research uncovered other examples of cotenancy contracts, a common one being the joint ownership of specialized printing facilities by a consortium of newspapers in a city. Clearly, who prints the newspapers is a production issue potentially separable from the competition of newspapers for subscribers and advertising services. The courts repeatedly affirmed this principle when such cotenancy contracts attempted to include marketing and pricing conditions in what was ostensibly a shared production agreement (Reynolds 1990). Thus, our conception of a joint venture property right regime had already been well articulated in court cases involving newspapers. There was no new principle, only the question of how it might be reformulated for application to network industries.

This model of cotenancy as an instrument of competition was further elaborated in Smith (1988, 1993) and tested experimentally in the context of a natural gas pipeline network funded by the Federal Energy Regulatory Commission (Rassenti, Reynolds and Smith 1994). The model would also play a facilitative role in our consulting on privatization in New Zealand. But such discussions are far from culminating in a completed instrument, with many practical implementation difficulties remaining.[2]

Aftermath of the Arizona Study

By 1985 when the study report was filed and presentations made to the ACC, the political composition of the commission had altered, and the immediate impact of the recommendation for deregulation on Arizona policy was nil. By the time our final report was completed the commission was composed of new elected office holders and they considered our proposal to be impractical, idealistic and politically infeasible. Of course the commission's actions made the last claim a self-fulfilling truth. Unknown to us at the time, subsequent developments would reveal that this experience was a minor battle in a wider war for institutional change that would begin abroad but would ultimately spread to the United States, but with less success, we believe, than abroad.

Contrary to the position of the new commission, we considered our proposal eminently feasible in the electronic age, though in need of far more fundamental research, and resolved to undertake controlled experimental studies of various issues in the deregulation debate. Progress on this objective, however, was slow due to inadequate funding, and the fact that the cost of software development for the laboratory study of electronic trading in the context of electric networks

[2]Hugh Outhred (2001) notes that there is ongoing work in Australia under the NECA code-review process to explore practical implementations of network property rights (see www.neca.com.au).

was higher than for traditional forms of experimental research. Nevertheless, by 1987 we had conducted several pilot experiments in a six-node electric power network with three fixed inelastic nodal demand centers, and nine gencos (described in Rassenti and Smith 1986). The gencos, located at various nodes, submitted sealed offer price schedules each trading period to supply power over transmission lines whose energy losses were proportional to the square of energy injected. A valuable lesson from this unpublished research was the ease with which gencos could push up prices against inelastic demands by bulk buyers using a mechanism that did not permit demand-side bidding to implement consumer willingness to have deliveries interrupted conditional on price. This was our first brush with the important principle that competition is compromised in supply-side auctions in which buyers are passive and are unable through the mechanism to enter demand-side bid schedules. The California electricity market is now experiencing this principle in spades, but it was foreshadowed in the experience with privatization in England, and in other spot markets abroad and in the United States. We report experiments below that provide a rigorous demonstration that when the spot auction mechanism in common use around the world is supplemented by demand-side bidding it provides a property right regime that is a remarkably effective antitrust remedy.

Domestically, through the 1980s and into the 1990s, electric power would remain subject to American style rate-of-return regulation, while abroad government owned electric (and other) utilities were under political pressure to explore the use of markets for the management electrical energy allocations. Industry performance was seen as abysmal in the 1980s, causing countries such as Chile, the United Kingdom, and New Zealand to think the unthinkable: decentralization might be preferable to either government planning or direct regulation. But how might it be done?

How Experiments Were Used to Inform Privatization: New Zealand and Australia

Beginning in 1986 we initiated software development and a series of experiments to study mechanism design, industry structure, pricing, transmission and market power issues in electricity markets. (Rassenti and Smith 1986; Backerman, Rassenti, and Smith 1997; Backerman et al. 1997; Denton, Rassenti, and Smith 1998; Rassenti, Smith, and Wilson, 2000.) While this research was proceeding, one of the authors (Smith) consulted for the New Zealand Treasury in 1991 and two of us (Rassenti and Smith) in 1993, and also for Australia's Prospect Electricity in 1993 and National Grid Management Council in 1994. The impetus in New Zealand was our 1985 ACC report that fell unceremoniously on deaf ears in Arizona, but attracted attention abroad.

What Were the Questions?

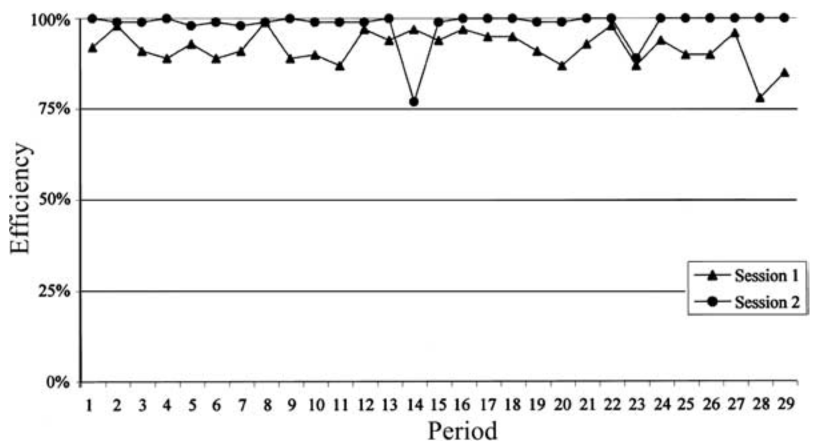
The two following research questions, addressed in laboratory electricity network experiments after 1986, and motivated by our ACC study, provided the primary information base for informing our contribution to the privatization process in electricity down under.

1. Is decentralization feasible and, if so, is it efficient to combine decentralized property rights in energy supply with a computer coordinated spot market and optimization schemes for dispatching generators?
2. How is the answer to question 1 affected by demand-side bidding?

Before the first experimental observations were made it was an open question whether it was feasible to replace engineering cost minimization in large integrated utility hierarchies with independent gencos submitting node-specific asking price schedules, bulk buyers submitting node-specific bid price schedules, and allocations determined by algorithms maximizing the gains from exchange implied by these marginal bid/ask schedules and the physical characteristics (loss characteristics and capacity constraints) of the grid. Engineers and managers to whom we made presentations were overwhelming skeptical—in fact were openly hostile—that such a system could be relied upon. ("You can't control electricity flows with markets—I know, because I'm an engineer.") The conventional wisdom of economists had been stated as follows:

> Generation and transmission are intimately and fundamentally related by the interconnections that the transmission system provides and the associated opportunities for area wide optimization . . . Because of these relationships, decisions either short-run or long-run, made at any point in a power system affect costs everywhere in the system. These effects raise potential externality problems. If a power system's components are owned by more than one firm, it is crucial for the efficiency of short-run and long-run decision making that all owners of parts of the system take into account all effects of their actions, not just the effects on the part of the system they own [Joskow and Schmalensee 1983: 63].

FIGURE 1
EFFICIENCY WITH EXPERIENCED SUBJECTS



Experimental markets, in which all energy sales and purchases were expressed as offers to sell and bids to buy so that allocations were determined simultaneously given the physical properties of the grid, demonstrated that energy market deregulation was eminently feasible. Furthermore, short-run efficiency was high—on the order of 90–100 percent of the maximum economic surplus, or gains from exchange were achieved in markets with very few participants. Figure 1 shows a plot of efficiency for two experimental sessions consisting of a series of 30 trading periods using experienced subjects in a 3-node radial network with 4 bulk buyers and 6 gencos (Backerman, Rassenti, and Smith 1997). Why are there no important efficiency losses due to short-run externalities? The answer resides in the condition that all allocations are determined simultaneously. Power loss on shared transmission lines varies as the square of total power injected. Therefore, genco A suffers higher costs of energy loss if genco B is using the same line. But if optimization is based upon every agent's marginal willingness to pay or to supply, with price and allocations determined simultaneously, then each agent bears the appropriate opportunity cost that his action imposes on all others at the margin. The problem is solved by the simultaneous submission of bid/ask schedules to which are applied algorithms for maximizing the implied gains from exchange taking account of system transmission losses.

But there are many other potential "external effects," besides shared system energy losses, that in principle are or can be internalized via mechanisms that link bid/ask schedules with system constraints through rule governed coordination: (i) voltage "constraints" (as they are so treated, technically, in all operating systems today), requiring "reactive power" to be produced, and therefore priced in the market if such constraints are to be incorporated into the market process;[3] (ii) intertemporal links on both the demand and generator sides of the market historically have implied the need for optimization over time, not just in the current spot market, but as shown by Kaye and Outhred (1989) and Kaye, Outhred, and Bannister (1990) the primary intertemporal coordination requirements can be met by forward markets; (iii) contingency provisions such as generator and transmission reserves to avoid blackouts from unscheduled equipment outages, and to avoid unstable cascades of outages that spread through the network.[4]

Turning to the second question, both regulation and government ownership have produced industries with a strong supply-side orientation. The politics of power yields a system in which (i) there are severe political repercussions if consumers "lose lights" too often, and (ii) consumers making decisions have no means of directly (or indirectly through wholesale markets) comparing the cost of new capacity with the cost of interruptions on peak or in emergencies. Consequently, adequate reserve capacity in generation and transmission requires supply-side investment sufficient to meet all demand, plus a large margin for security of supply. The regulatory and government-owned systems had no incentive to install technologies for relieving load stress by introducing time-of-demand pricing, and voluntary interruptible contracts for customers. For this to occur power users must have the real-time spot market capacity to either directly reduce

[3]Maintaining voltage to avoid "brownouts" requires generators, or special compensating devices, to provide local reactive power. Since generators can produce either reactive or active power (the latter is energy that does work) in variable proportions, (i) is a source of "externality" only if it is not priced, which is the universal practice inherited from centrally owned or regulated systems. We plan experimental designs to price reactive power as just another commodity.

[4]Generator (spinning) reserve can be supplied by a market for standby capacity in addition to the energy market. (See Olson, Rassenti, and Smith 2001 for an experimental study of such simultaneous markets). A simple such market (without network complications) is provided when you rent an automobile: if you use it you buy the gas in a separate energy market; if you do not use it then it is in standby reserve for contingent use. To maintain transmission reserves lines are typically constrained to carry much less than their thermal capacities by engineers whose zeal in minimizing the risk of losing a line, is not necessarily economical. A standard rule, based on $n-1$ analysis, is to set the capacity of each line in a network so that if any one line goes out the remaining $n-1$ lines can carry the peak load; if you want still more security $n-2$ analysis is applied and so on. Of course this approach begs the question of what price security. Can catastrophic insurance principles be applied with a variable premium that increases with monitored capacity utilization?

consumption in response to price increases, or indirectly by contract with the distributor to effect reduced deliveries in response to price increases. As we shall see below, the capability for interruption of energy flows must be expressible in the spot market if prices are to be adequately disciplined.

New Zealand

ESL's consulting work in New Zealand was directed entirely to questions of how a privatized NZ electrical industry, and a wholesale power market, might be structured. Intellectually, in the early 1980s, the sea change in issues of privatization versus government ownership and regulation was so drastic in the direction of economic liberalization that electricity reform seemed certain. The election of a new reform-committed Labour government was followed by a foreign exchange crisis the next day. All government enterprises had performed so poorly, and were such a drain on the Treasury that the country was soured on the "NZ (socialist) experiment." Everywhere in New Zealand, by 1991, were to be found people expressing the "user pays" principle as a slogan of reform.[5] This exuberance, strong in the late 1980s and early 1990s is now much abated, even reversed.

> New Zealand . . . retains large state-owned corporations that are suitable for privatization, but . . . its privatization activity has been muted for much of the 1990s. This decline reflects political perceptions of the privatization act as well as the resolution of property right issues, some of which arise from considerations of industry structure that is suitable for light-handed regulation, and some from the potential settlement of Maori claims on the crown [Evans 1998: 3].

ESL consulting for the New Zealand Treasury in 1991, and later for Transpower, NZ in 1993, created as the state-owned enterprise that maintained and operated the high voltage grid, emphasized privatizing transmission, transmission pricing, and demand-side bidding.

Privatizing Transmission

What might be the incentive and ownership structure that should be implemented for the New Zealand grid, and for the market dis-

[5]The impetus for reform was a drastic reduction in the performance of the NZ economy from 1953 to the late 1970s. New Zealand had the world's third-highest per capita income in 1953 (behind the United States and Canada but tied with Switzerland) and by 1978 had slipped to twenty-second (less than half the per capita income of Switzerland). See McMillan (1998).

patch center that would determine allocations of energy supply among decentralized generator owners who bid into the spot market?

Our recommendations had their genesis in our 1985 ACC study of cotenancy, but the basic idea—a cotenacy property right system—was substantially extended and tailored to fit the special physical properties of electric power flows in interconnected alternating current (AC) networks. Primarily these properties are twofold: (a) flows on individual links in the network cannot be precisely controlled because in AC networks there has not existed anything analogous to the valves on links in fluid and gas pipeline networks; (b) optimization in such networks requires knowledge of willingness-to-pay bid demand values at delivery nodes, offer supply terms at power injection nodes, and the physical properties (loss characteristics and capacity constraints) of all elements of the network. One can then solve simultaneously for the pattern of energy injections and deliveries that satisfy all demands and constraints while maximizing the short-run gains from exchange based on all such information. These two characteristics combined imply that it is not possible to specify well-defined path rights from any source node to and delivery node. The flow on a given path may be optimal at one time, but with a change in the supply and demand pattern, and with different transmission constraints binding, the flow on that path may be much different, even reversed at another time.

We proposed that these characteristics of the electricity industry be supported by a property right regime with the following commensurate features when the system is privatized as a joint (competitively ruled) venture, or cotenancy, owned by all users.

(a) At each energy injection node is connected a set of generators with some specified capacity that has occurred in history up to the time of privatization. That capacity is assumed to reflect the benefits, based on historical utilization rates, and site value of locating the capacity where it resides.

(b) Similarly, each delivery node will have associated with it a capacity to withdraw power.

(c) Rights to inject (or withdraw) power at each node can then be defined and certificated in capacity terms based on historical investment.

(d) Each generator has the right to submit a bid supply schedule indicating the various quantities the supplier is willing to inject at corresponding stated asking prices, where the schedule is restricted not to exceed a total offer of that generator's capacity rights at its connection node. How much of this offer is accepted by the dispatch center, depends on the offer terms of competing suppliers at the same or other nodes, the nodal pattern of demand, and the physical properties of the grid at any time. Stability, security and voltage considerations may require certain key generator offers to be accepted in exception to the general merit order rule that the lowest priced generators have priority over higher priced ones. Such key generators are likely to change with the network load configuration. Thus, each generator merely has a right to offer up to its capacity in units of power, not the right for the offer to be accepted. Such uncertainties are inherent in the nature of the system, and property rights must reflect these contingencies. Technological and institutional innovation may alleviate exposure to these risks, and such developments must be allowed, and have an incentive, to happen.

(e) These capacity rights can be freely traded, leased or rented to others subject only to contract laws applicable to any industry; but as in other industries, electricity may leave its own footprints on the form of those contracts.

(f) Any individual user in this structure, or any group of users forming a consortium, is free to invest in increasing the capacity of any line or lines in the system. Those making the investment will acquire rights, as in (c)–(e) above, to any increase in capacity at individual nodes that is made possible by the investment. Any such increases in capacity will be uncertain, and based on imperfect engineering simulations that are commonly used to evaluate and site capacity expansions.

(g) Finally, since incumbent users may not be well motivated to expand capacity, the cotenants cannot prevent the entry of new investors who invest in line capacity expansion, and acquire rights to the consequent increase in nodal rights to inject (or withdraw) power.

Transmission Pricing

Given the joint ownership structure indicated above, all users share output-invariant operating and maintenance costs in proportion to their respective capacity rights. The primary variable cost of transmission is the energy lost in the transfer of power from source nodes to delivery nodes. This loss (per mile of line) in high voltage lines varies approximately as the square of energy injected—less energy is received than is sent. Hence, if the average loss per unit is A (usually a number between .02 and .2) for a given line, the marginal loss is $M = 2A$. This implies that if the price at an upstream injection node is P, then at any downstream node the price is $P' = P + PM$, i.e. the delivery price is the price at the injection point plus the marginal cost of energy lost in delivery. Note that PM is the true opportunity cost of energy lost in transmission, and all buyers served by remote generators must pay this cost in an efficient energy supply network. On long lines where the average loss at peak demand can be up to 20 percent ($A = .2$), the nodal price difference, $P' - P = 2AP$ can be up to 40 percent of the delivered price.[6]

Demand-Side Bidding

Competition is greatly enhanced if wholesale buyers can bid into the spot market using discretionary demand steps that define price levels above which they are prepared to interrupt corresponding blocks of power consumed. As we shall see, demand-side bidding also reduces price spikes on peak. Moreover, interruptible flows can substitute for security reserves of generation capacity, while reducing the prospect that transmission lines will become constrained.

New Zealand deliberations on structuring the grid continue. However, the functions of the spot market, called the New Zealand Electricity Market (NZEM), have been structured as a ruled-governed joint venture. (For a detailed report see, Arnold and Evans, 2001; also see NZEM 1999). Only three countries have implemented policies requiring the grid users to fund investment expansions: Chile, Peru, and Argentina. In all three cases, however, the multiple owners operate under regulated prices (Kleindorfer 1998: 69). Thus, no country has implemented a completely privatized grid regulated only by property rights, nor is this likely to be achieved in the near future.

Although our fledgling proposals for structuring joint ownership of the grid have not been implemented, and indeed require a lot more intensive work to be operational, the New Zealand spot market implements both the marginal loss pricing of transmission and demand-side bidding. It is important, however, to note that nodal energy pricing in New Zealand does not provide ex ante real-time prices that can be avoided by action of buyers and sellers in the current period. Prices are an ex post cost recovery and distribution scheme, and effect decisions only insofar as events/conditions are repeated and anticipated by decision makers. The same is true for the systems implemented in California and the Middle Atlantic regions in the United States. This is partly the result of industry traditions in which people

[6]As a practical matter, because of the cost of metering and monitoring, network pricing always involves a certain amount of aggregation of subsystems into representative nodes or paths. Hence, the above principles are indeed conceptual, and only imperfectly captured in any actual operating system. Moreover, low voltage distribution systems do not follow the square loss law rule at all well, and losses are commonly averaged across the high density of users.

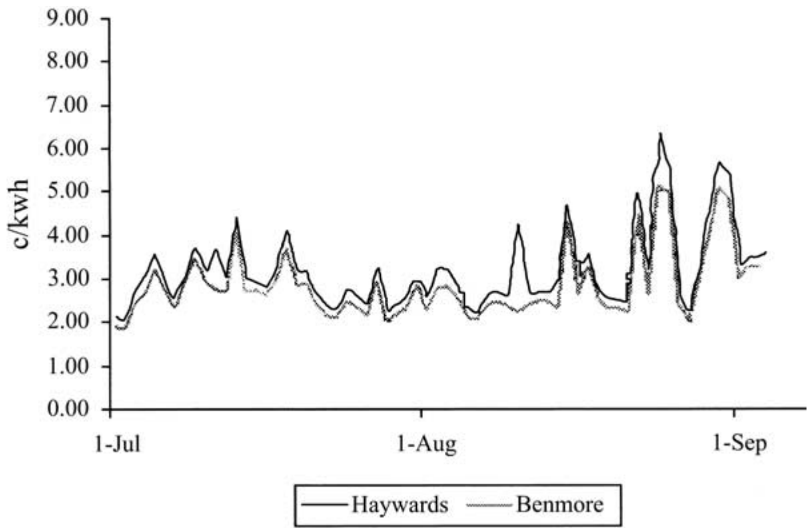
think of prices as cost recovery devices rather than signals of avoidable opportunity costs, and partly a consequence of implementing the appropriate technology and institutional arrangements. New Zealand, however, is moving to implement true avoidable cost pricing as used now in Australia (see below).

Marginal cost pricing of transmission is politically very difficult to implement in democratic regimes—three other countries (Chile, Peru, and Australia) have adopted it (Kleindorfer 1998: 69). Strong political pressures favor averaging transmission losses across all customers. This creates an incorrectly priced external effect that is avoidable by appropriate specification of property right rules, and illustrates one of the many externality problems *created, not solved* by collective action. With minor exceptions averaging losses over all customers was the universal practice in both state owned and American style regulatory regimes, and this practice dies very hard. People do not understand the opportunity cost/efficiency principle here: each agent pays the cost that his consumption imposes on others, thereby eliminating external effects. But collective agreement is necessary to implement the application of this principle to grid pricing. (Note that the principle creates no problem in the airline or accommodation industries, where on-peak prices emerge spontaneously in competition, à la Hayek's 1945 perceptive argument, and collective agreements are not needed. This illustrates one of the many hazards in decentralizing interdependent network industries using some collective agreement process.)

Most of the New Zealand population and electricity demand is on the North Island, while most of the generation capacity is on the South Island. It is some 900 miles from the bottom of the South Island, where the most remote generators are sited, to the top of the North Island, where the largest concentration of population is located (Auckland). Consequently, at peak demand, with no constrained lines causing a further price difference due to congestion, there is a price difference of approximately 33 percent between the two most remotely separated nodes. Figure 2 provides a chart of New Zealand electricity prices at the inter-island link, Haywards and Benmore in the South (not at the two extreme nodes), for the winter months of July and August, when the heating demand for energy is greatest.

Relevant to demand-side bidding the New Zealand Electric Market (NZEM) rules specify that "Each trading day, each Purchaser Class Market Participant will submit to the Scheduler the bids pursuant to which . . . (that Participant) . . . is prepared to purchase Electricity from the Clearing Manager for each trading period of the following trading day" (NZEM 1999: B.2.1). Such bids specify the relevant

FIGURE 2
AVERAGE ENERGY PRICES IN NEW ZEALAND, 2000



SOURCE: Chart was downloaded from www.m-co.co.nz/C2dPricesMonth/000905.htm.

trading periods, the grid exit node, must represent reasonable endeavors to predict demand, and specify up to 10 prices (price steps or "bands") and corresponding quantities. There are no upper or lower limits on prices "The highest price band for each bid will be deemed to start at a quantity of zero" (NZEM 1999: B.2.3). Note that this provision defines the strike price where the Marshallian bid demand schedule intersects the price axis. Since the technology for interrupting flows is limited, these provisions of the NZEM are currently little used (as reported to us in private conversation with Lewis Evans at Victoria University, NZ), but the institutional stage is set for more extensive demand-side bidding as the appropriate technology becomes more available and cheaper. They will become more significant when New Zealand implements real-time pricing.

Australia

We were invited to visit Australia in 1993 by Prospect Electricity (now part of Integral Energy) in New South Wales, the second largest distribution company in that state. Australia, unlike New Zealand (initially), was not committed to privatizing electricity, although the political debate had begun. Rather, the commitment was to decentralization, setting up a national wholesale market. This was the charge of the National Grid Management Council (NGMC). (Privatization if it occurred was the providence of the states, which were the owners of existing power system assets. All generation, transmission, and distribution systems remain publicly owned even today, with the exception of Victoria where all are privately owned, while South Australia has executed 200 year leases of its assets to private entities.)[7] It was during this visit that we learned that the constituency for privatization was made up of bulk buyers—commercial, industrial, and distribution companies—who expressed the belief that the state government-owned electricity industries were producing power at exorbitant cost, and this was hampering the ability of Australia's energy intensive industries to compete in world markets. Primarily our sponsors consisted of the buyer side of the industry, and our task was to supply market information and deliver demonstration technology: give lectures, seminars and conduct experimental workshops with a wide spectrum of industry and government representatives who would participate in our prototype wholesale electricity experiments, demonstrating feasibility, efficiency, and possible structural features for a decentralized wholesale market, with the extent and form of decentralization yet to be determined. These lectures and workshops were well attended, but with understandably more enthusiasm coming from the demand side than the supply side. Such was the political environment as we saw it.

Subsequently, the central government created the National Grid Management Council to plan and oversee a wholesale energy market embracing the states, integrated by a national interconnected grid. This led to a controversial "paper trial" (cost, $2 million) in which participants walked through proposed procedures for bidding and clearing in a spot energy market. Our Australian contacts pressed, and won, approval to conduct laboratory experiments with a prototype for the proposed market. We were consultants on software specifications, and experimental design, but with all development and experiments to be conducted in Australia. This ultimately led to a two-week (7 hours per day) electronic trading experiment using nonindustry participants trained in the exchange procedures, and earning significant cash profits based on induced costs, and demands, and on Australian parameters and grid characteristics. We advised against using any

[7]Based on private correspondence with Hugh Outhred.

industry participants because of their known political biases for or against the impending market reforms.

On December 13, 1998, the National Electricity Market began trading Australian electricity. Prior to that period separate markets traded power in the States of Victoria and New South Wales as early as 1996.

In summary, experimental methods in economics served to facilitate the development of a wholesale electricity market in Australia in the following ways:

1. It provided a pre-1991 experimental database demonstrating the feasibility of using a smart market, price signals to coordinate production and transmission over huge geographical areas, and to help inform the political decision process.
2. Treatment results from specific experimental designs suggested that overall market efficiency, price volatility and the distribution of surplus among the buyers, sellers and the transmission system were significantly impacted by the following: transmission and auction market pricing rules, whether or not there was demand-side bidding, and whether or not transmission line constraints were binding.
3. As noted in communication with Hugh Outhred, the new experiments "at UNSW also demonstrated the importance of forward markets in containing market power" (see Outhred and Kaye 1996).
4. It provided hands-on experience and training for managers and technical staff, and alerted the principal agents involved in the wholesale market to some of the potential design issues in the process.
5. It enabled the Australians to go through the process of market prototype software development, to conduct experiments using Australian grid and generator cost parameters, and to learn much more about how their proposed market system might work prior to actual trading in Victoria and New South Wales.

The wholesale market in Australia has implemented features that make it among the most advanced anywhere from the perspective of reflecting good economic design principles, although it is important to emphasize that those principles are under ongoing review and modification in the light of changing experience and technology. We mention two features central to the issues discussed above that were in the National Electric Code *prior* to their experiments (quoted from personal correspondence with Hugh Outhred, February 2, 2001):

(a) "Network pricing in Australia does incorporate marginal network losses in the following manner: the 'notional interconnectors' between regions include . . . (adjustment for) . . . marginal losses . . . directly into the process for setting five-minute prices; inter-regional transmission loss factors are set annually on the basis of average marginal network losses (the averaging period may be shortened at some future time) . . ." Hence, the loss factors, as such, are not based on current real-time conditions, as are the flows to which the factors are applied.

(b) "The Australian National Electric Market Rules (NEM) . . . (also) . . . incorporate the demand side—both formally as bids . . . and informally as price elasticity. The latter option exists because: half-hourly prices are forecast at least 24 hours ahead and broadcast to all market participants (supply and demand side); participants can change their bids and offers from the time of their original submission (one day ahead) down to the half hour to which they apply; the actual spot price is set in 'real-time' and broadcast to all participants—a consumer can simply reduce demand in response to that price signal and thus avoid paying the price. That facility is now being used in practice, both by a consumer participating directly in the NEM and by retailers backed up by discretionary demand reduction contracts with final consumers." It is evident, however, that "much more development (is) needed" [Outhred 2001: 20].

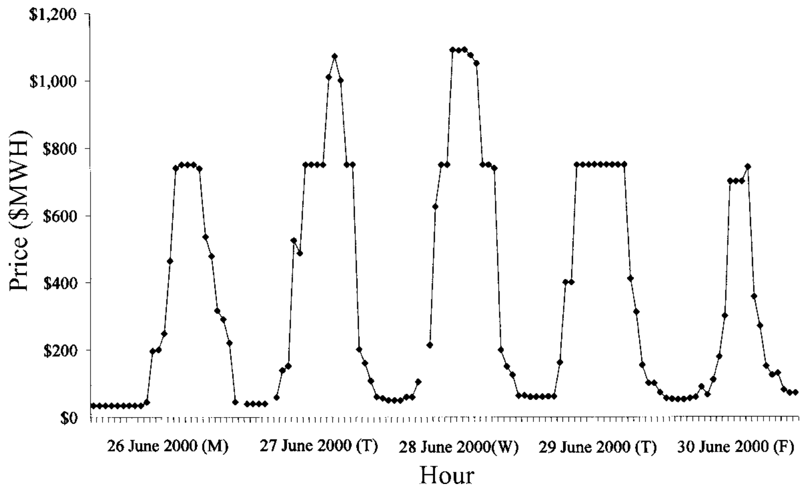
The United States

The deregulation of electricity did not impact the United States until privatization/decentralization reform was well advanced abroad. Viewed from the perspective of those of us interested in market design for deregulation, the U.S. experience has been disappointing, and the design details heavily politicized. At the start, the industry strongly opposed deregulation. Nothing new here, as the same was predominantly true for airline, gas, railroad, and trucking deregulation. But with electricity there was the need for state or regional *collective agreement* on how the industry would be restructured, and what rules would govern market operation since there was clear need for computer coordination of generator loads to meet instantaneous demand on highly interconnected networks. (No need for such agreement in the deregulated airline industry. The routes no longer had to be certificated, the industry was regulated by free entry and exit, and what emerged spontaneously in response to the demand for frequent low-cost service was the hub-and-spoke structure that was anticipated and deliberately planned by no one.) Originally, for example circa 1985 when we finished our ACC report, the industry had argued that deregulation was not technically feasible, but that proposition had been shot down all over the world by decentralization programs none of which had followed American style rate of return regulation. There were various forms of "light-handed" regulation such as price caps on charges for the "wires" business—high voltage transmission or local low voltage distribution—but energy was being priced competitively limited only by technology and the state of learning. No one abroad wanted to use the American model, which was perceived to be broken just as badly as the state owned or dominated models that were being reformed.

In this environment, once the writing was on the wall, the utilities focused not on questions of market design and efficient spot markets, but on lobbying for fixed new monthly charges to cover their alleged "stranded costs." This was price design for revenue protection not *market* design for efficiency. Most economists seemed to accept the need for such compensation, either because it was "fair" for utilities to recover the cost of investments made in good faith under a regulatory regime that was being replaced (Baumol and Sidak 1995), or because it was considered the political price to be paid for utility support for deregulation (Block and Leonard 1998). Since the utilities were already privately owned, had long engaged in bilateral economy energy exchanges, and energy marketers, or intermediaries, had emerged to facilitate such contracts, there was opposition to the very idea of an open spot market. Bilateral interests wanted to report only origin and destination flows to schedulers, with prices remaining proprietary. Ironically, the bilateral special interest groups had been fostered by legislation intended to move the industry toward market liberalization: the Public Utility Regulatory Policies Act of 1978, and the Energy Policy Act of 1992. These initiatives were designed to facilitate transmission access by independent power producers as a step toward fostering the development of wholesale power markets. (Bear in mind that such access was being opposed by some utilities, and federal action was seen as necessary). The bilateral trading model was promoted, partly because of its perceived success in reforming the gas industry, but also because gas marketing intermediaries wanted to expand into electrical energy markets. California followed the bilateral model in restructuring electricity. We long regarded this model as misguided: bilateral bargaining in the electronic age could not provide the foundation for an efficient market model of interdependent (pipeline or transmission) networks.[8] California, however,

[8]For a critique of this trend see Smith (1987, 1996), and for studies of smart computer assisted markets in gas pipeline networks see McCabe, Rassenti, and Smith (1989, 1990), and Rassenti, Reynolds, and Smith (1994).

FIGURE 3
CALIFORNIA PX PRICES



did require the demand of the Investor owner Utilities to be processed through the CalPX, but these demand quantity bids were "at market" (pay whatever is the supply-side asking price that clears the market); they were not price contingent bids implemented by interruptible service contracts.

Thus, in California and elsewhere, the new "wires" utilities succeeded in instituting new fixed monthly charges to cover their stranded costs, and fixed per unit energy charges for retail customers, but no one was preparing for and investing in the technology for demand-side bidding as an instrument to discipline prices in the hourly spot market and to provide incentives for users to reduce demand or switch their time-of-day consumption from higher to lower cost periods. Imagine what would be the consequences to the airlines, and all of their passengers, if, in order to be licensed, airlines were required to charge all passengers an identical regulated monthly access fee and a fixed price per mile traveled*, independent of flight destination, time of day, time of week, season or holidays, and independent of the flier's willingness to pay*!

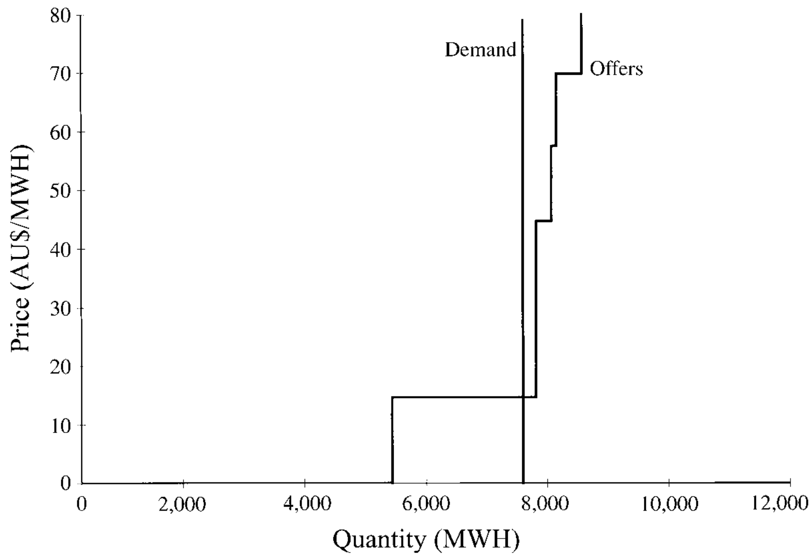
Figure 3 illustrates a typical 24-hour period of price variation on the California PX (their open spot market exchange). Since most of the power was either traded via bilateral contracts at secret prices, not part of the spot market, or through the PX as bids "at market," demand was not price responsive. Observe in Figure 3 that the peak demand and most of the "shoulder" transition demand (between peak and off peak) are at prices above 10 cents per kilowatt ($100 per megawatt), and are therefore far in excess of what local distributors collect from their residential customers. There are numerous other examples of on-peak price spikes of up to 10 or more times the normal energy prices (in the $25–$30 per megawatt range). (See the Bloomberg Daily Power Report, online, Summer 1999 for a report on sharp price spikes in the Midwest and South.) These price differences imply an enormous rate of return on investment in contracts for voluntary selective interruption of energy deliveries, with gains shared by both the distributor and its customers.

Demand-Side Bidding Controls Market Power and Price Spikes

Earlier experimental market research, cited above, used demand-side bidding, and we observed very competitive results. New experiments study this issue much more systematically in the design reported by Rassenti, Smith, and Wilson (2000) comparing prices with and without demand-side bidding. Bulk buyers submit discretionary bid steps reflecting the prices above which they are prepared to reduce demand by invoking their contracts for interrupting deliveries. It is important in a competitive electricity market that bulk energy providers contract for *discretionary* interruption of (suitably compensated) consumers. Why? Because then their bids in the wholesale market cannot be known with certainty by the supply-side bidders, and demand-side bidding can better deter supply-side market power. The problem created by inadequate price responsive demand in a supply-side dominated auction can be illustrated with the chart shown in Figure 4, due to Outhred. In such a market, the clearing price is sensitive to the asking prices submitted by peaking generators in short supply, especially near peaks in demand. Thus, in Figure 4, the price is $15 per MW with demand 7,700 MW, but if demand had been 8,000 MW, the spot price would have been $45 per MW, and at a demand level of 9,000 MW, the price would have been indeterminate forcing the dispatch center to use security reserves or to involuntarily interrupt customers. Unquestionably, many consumers would have been prepared to reduce demand to avoid such a price spike, provided that they had been given the opportunity and incentives commensurate with the savings. In the United States are such conditions to be judged a problem in supply-side market power, or an institutional and incentive failure of the market mechanism to implement responsive demand? The tendency is to blame market power although in another industry—hotel/motel accommodations, or airline

FIGURE 4

PRICE DETERMINATION IN THE AUSTRALIAN ELECTRICITY MARKET



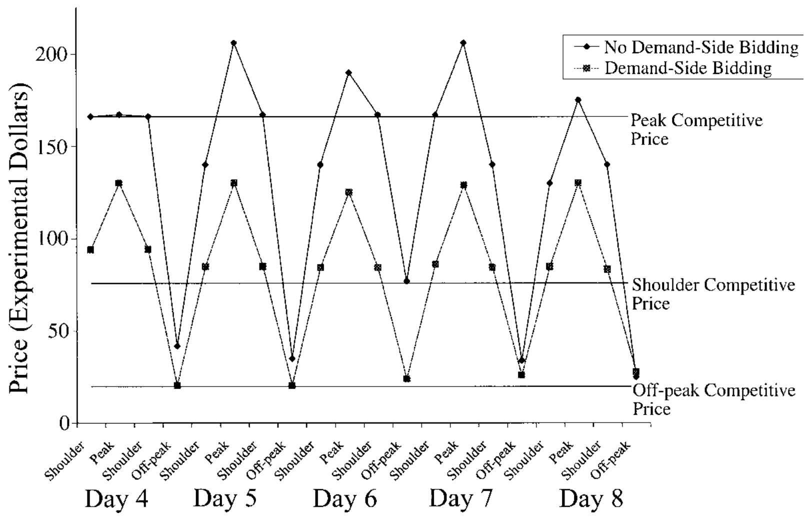
SOURCE: This graph is drawn from Hugh Outhred's presentation entitled "Australia: Spot Trading Results and Implications for Ancillary Services," 5 January 2000. The data are for the 17 May 1996, targeting 2000.

seat pricing, where the product also is nonstorable—demand is strongly responsive to time variable competitive prices.

Figure 5 plots experimental data comparing prices with and without demand-side bidding over the course of 5 "days" of trading. Each day in an experiment consists of a cycle of four demand pricing periods: shoulder, peak, shoulder, and off peak. Hence, the experiments consolidate the shoulder transitions, peak, and off-peak hours (shown in Figure 3) into four simpler time blocks for auction price determination. Note that when there is no demand-side bidding, prices are much increased, well in excess of the controlled experimental competitive prices, especially on the shoulder and peak demand periods. Both generator "market power" and upward price spikes are effectively controlled by the introduction of demand-side bidding leaving all other features of the market unchanged. In these experiments a very modest proportion (16 percent) of peak demand is interruptible by wholesale buyers; most of the on peak demand (84 percent) is what the industry calls firm or "must serve" demand.

FIGURE 5

An Example of the Effect of Demand-Side Bidding

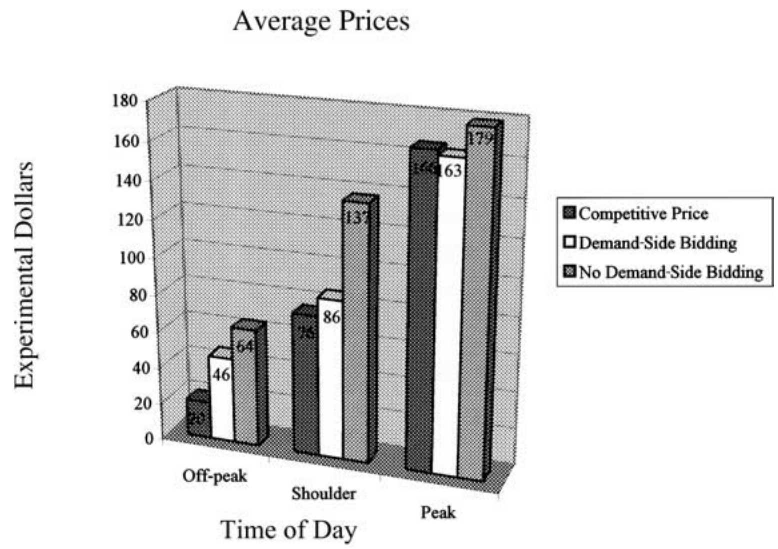


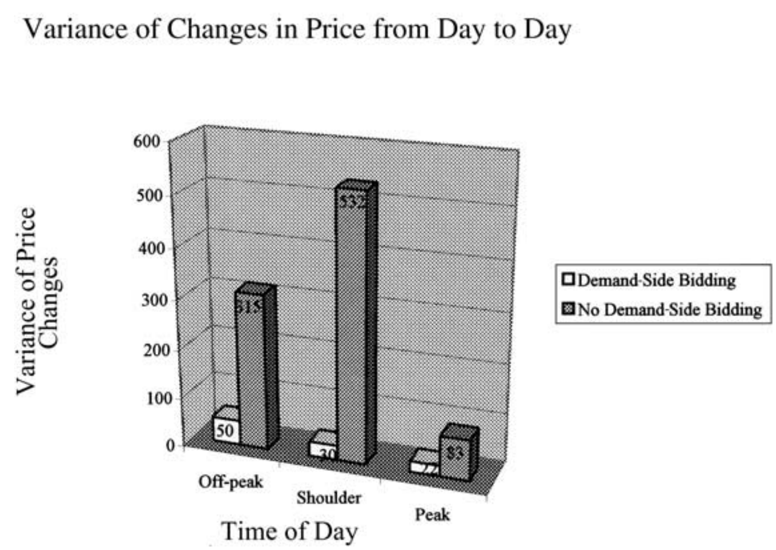
The chart in Figure 5 plots the data from just one of four independent experimental comparisons reported in Rassenti, Smith and Wilson (2000). Figure 6 provides a bar graph summarizing all of the experimental results. With demand-side bidding the average level of prices is reduced in all segments of the daily demand cycle, while the great variability in price changes is nearly eliminated.

Implications for Electricity Deregulation in the United States

The computerization of laboratory market experiments using profit-motivated human subjects in the 1970s unexpectedly revolutionized our thinking about the purpose and uses of experiments. In particular we soon came to recognize that the laboratory could be used to test-bed new electronic trading systems for application to industries traditionally perceived as requiring hierarchical organization and government regulation to achieve proper coordination and control over the resulting legally franchised monopolies. Electricity was a prime example, and we attempted to use our first experience with what we called "smart computer assisted markets" to inform Arizona's cautious and tentative interest in restructuring its electrical industry to rely on markets to regulate the energy segment of the industry. Failing at the time to influence policy, our effort was not

FIGURE 6
PRICES AND VOLATILITY WITH AND WITHOUT DEMAND-SIDE BIDDING





ignored abroad, and we participated as consultants in developing proposals and the use of experiments to help inform some of the key research issues in decentralization, and to serve as a hands-on training tool for those managing the transition. Decentralization required the creation of new property rights: a governance structure and efficient pricing for the grid, generator entry and exit rules, market rules governing messages and contracts in the context of computer controlled coordination, optimization, and communication, but with all outcomes driven by the decisions of dispersed agents whose circumstances of time and place were reflected in market bids to buy or offers to sell.

In the United States the industry was already privatized, but subject to centralized state and national price regulation based on a "fair" return on investment. With the proposed deregulation of electric utility prices and consumption each state or region needed to develop a plan for restructuring their industry and specifying the auction market rules for determining the real-time wholesale price of energy. Without exception, the resulting market designs, hammered out by regulators, consultants, industry representatives, and various power-marketing intermediaries, all employed supply-side bidding mechanisms for the hourly spot market. These spot markets were supplemented with wide ranging freedom for power users, producers, and intermediaries to engage in a variety of bilateral contracts outside of direct price discipline by the spot market. For the spot market this supply-side emphasis meant that any user, regardless of the individual circumstances of that consumer's need for an uninterruptible flow of energy, would be guaranteed that this demand would be served. Bilateral contractors could agree to allow various degrees of firmness of demand to impinge on contract terms. But in this longer-term contract market prices are negotiated and secret, and are not subject to the direct real-time opportunity cost constraints provided by the spot market.

The "must serve" demand policy in the spot market was inherited from a rigid regulatory regime that politicized the reliability of electricity flows to all consumers, whatever the cost. This cost was collectivized by averaging it across all users regardless of individual consumer differences in willingness-to-pay for keeping the lights on. The local utility was expected to maintain service, or restore it quickly, even in inclement weather, spreading the cost of this super-reliability thinly over all customers. This cost included the maintenance of substantial reserves in generation and transmission capacity. Thus system reliability and the capacity to satisfy all retail demand were exclusively a supply-side adjustment problem. In providing this superior service to all, the supply side was always justified in claiming 100 percent cost recovery plus a fair profit. The consequence of this supply-side mindset was uncontrolled cost creep that increased to a gallop and ultimately became part of the political outcry for deregulation. Implicitly, however, the process of deregulation assumed that this built-in supply-side bias did not require fundamental rethinking when it came time to design spot markets for the new world of competition. As always in market institutions, the devil was in the details.

Beginning three years ago in Midwestern and Eastern markets peak prices hit short-run levels of 100 or more times the normal price level of \$20–\$30 per megawatt hour. This was the predictable direct consequence of *completely unresponsive spot demand impinging on responsive discretionary (bid) supply.* More recently the California spot market has been plagued by exorbitant increases in prices as illustrated in Figure 3. This has led to political action to impose price caps on this market, which, of course, can only discourage a positive supply response to the shortages. The move to replace American-style regulation with what may become known as American-style deregulation is in danger of being derailed by these interventions.

Controlled comparisons between markets with and without demand-side bidding, in which only 16 percent of peak demand can be voluntarily interrupted, show that the effect of demand-side bidding can dramatically lower both the level of prices and their volatility.

The public policy implications are evident: wholesale spot markets need to be strengthened institutionally by making explicit provision for demand-side bidding. Distributors need to incentivize more of their customers to accept contracts for voluntary power interruptions, or use time of day meters and load control systems to manage their own price responsivity. Industrial and commercial buyers who already have the capacity to handle interruptible energy supply, but who contract outside the spot market need adequate incentives to participate in the spot market where their more responsive demands can impact public prices. Distributors stand to gain by interrupting demand sufficiently to avoid paying higher peak and shoulder spot prices, and these savings can be used to pass on incentive discounts to customers whose demand, or portions of it, can be reduced or delayed to off-peak periods when supply capacity is ample. In California, news reports indicate that distributors have lost some \$10 billion buying high (Figure 3) and selling at vastly lower residential rates.

The technology and capacity for implementing such a policy already exists and can be expanded. This policy recognizes that adjustment to the daily, weekly, and seasonal variation in demand, and to the need to provide adequate security reserves, is as much a demand-side problem as it is a supply-side problem. The history of regulation has created an institutional environment that sees such adjustment as exclusively a supply responsibility, and views prices as an ex post means of cost recovery. The result is an inefficient, costly and inflexible system that has produced the recent price shocks and involuntary disruption of energy flows. Demand-side bidding and price feedback coupled with the supporting interruptible-service incentive contracts can eliminate unjustified price volatility, price increases and reduce the need for reserve supplies of generator and transmission capacity.

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Simple-Offer versus Complex-Offer Auctions in Deregulated Electricity Markets

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Abstract Previous research of complex-offer auctions designed for deregulated electricity markets finds that offer complexity allows great deal of strategic behavior, which consequently leads to anti-competitive and inefficient outcomes. In these complex-offer auctions, the sellers submit not only quantities and minimum prices at which they are willing to sell, but also start-up fees that are designed to reimburse the fixed start-up costs of the electric power generators. Using an experimental approach, I compare the performance of two complex-offer auctions against the performance of a simple-offer auction, in which the sellers have to recover all their generation costs – variable and fixed – through a uniform market-clearing price. I find that the simple-offer auction significantly reduces consumer prices and lowers price volatility. It mitigates anti-competitive effects that are present in complex-offer auctions and achieves allocative efficiency more quickly.

Keywords *Complex-offer auction, Electricity, Procurement, Efficiency, Two-part pricing, Avoidable fixed cost*

JEL Classification *C72, D4, D61, L94*

1 Introduction

11 billion kilowatt-hours were traded daily in the U.S. wholesale electric power markets in 2006. Average price ranged between a tenth of a mill and 50 cents per kWh[1]. Many of these markets employ auctions that differ from other widely used quantity-price offer auctions in their offer complexity. Besides the quantities and the minimum prices, at

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[1] Energy Information Administration, Form EIA-861, Annual Electric Power Industry Report.

which the electric power producers are willing to sell, the sellers may also declare their technical constraints and start-up fees that are designed to reimburse the fixed start-up costs of the generation plants. The start-up costs are avoidable fixed costs that create non-convex allocation problems. This paper investigates what value is gained from incorporating this complexity into deregulated electricity markets. The generation contracts are allocated daily by a sealed-offer auction that employs a computationally involved market-clearing algorithm. Besides applying a rule for offer selection, a market-clearing algorithm has to ensure that the system demand and reserve requirements are met over a particular time.

Baltaduonis (2007b) compares the performance of two such auctions with regard to consumer prices and efficiency by using a laboratory experiment. The major finding is that the sellers exploit the offer complexity to extract high payments from the buyers. Consequently, the outcomes result in substantial inefficiencies. In this paper, I use a laboratory experiment to contrast the performance of these complex-offer auctions (COAs) against the performance of a simple-offer auction (SOA) where the sellers can recover their generation costs – both variable and avoidable fixed – only through a uniform market-clearing price (MCP). The paper inquires if the SOA could mitigate the anti-competitive behavior that is present in the COAs.

Two COAs differ from each other in their market-clearing algorithms. An offer cost minimization (OCM) algorithm is currently used by independent system operators (ISOs) in the U.S. It relies on the traditional unit commitment approach.[2] The algorithm minimizes the total offered cost of electricity for a given demand as if all selected sellers

[2] For a bibliographical survey on the unit commitment problem see Padhy (2004).

would be paid their offered prices and fees. *Sequentially*, after the offers are selected, a uniform MCP is determined as the highest accepted price for that period. All selected sellers receive their individual start-up fees and the *uniform* MCP for the supplied electricity during that period.

Yan and Stern (2002) point out that the OCM algorithm does not ensure the lowest procurement cost of electricity to consumers for a given set of offers. This motivated Luh et al. (2005) to develop a payment cost minimization (PCM) algorithm that minimizes the actual procurement cost of electricity *simultaneously* determining a MCP as the highest accepted price during that period. As in the OCM auction, the selected sellers would receive their individual start-up fees and the *uniform* MCP for the supplied electricity.

Electrical engineers have studied non-convex optimization problems, similar to the OCM and the PCM algorithms, for many years. Attempts to improve these mechanisms heavily depend on the assumption of complete information about the generation costs of electric power.[3] Baltaduonis (2007b) reports that in both the OCM and the PCM auctions, sellers significantly raise the start-up fees and prices over their true start-up costs and variable production costs even in an environment with many competitors. Such behavior leads to both allocative and production inefficiencies. Thus, the theoretical assumption of truthful production cost revelation seems to be unwarranted.

To analyze the performance of the SOA I hold constant all other characteristics of the system described by Baltaduonis (2007b). The SOA is a less computationally involved auction than the COAs and thus more transparent to market participants. On the other

[3] For a recent work on mechanisms for markets with non-convexities that is motivated by electric power markets see O'Neill et al. (2004).

hand, the exact revelation of production costs is impossible in the SOA. The sellers have to mark up their offered prices to account for the fixed start-up costs or they might incur losses. A higher risk of losses becomes a concern.

Van Boening and Wilcox (1996), hereafter VW, report an experiment in which a continuous double SOA fails to converge and stabilize on 100% efficient allocations in an environment with avoidable fixed costs. Durham et al. (1996), hereafter DRSVW, explore two-part pricing competition in a sealed-offer auction experiment as a means of improving efficiency in the VW environment. DRSVW find that in a setting with experienced sellers and simulated buyers, this institution is effective in promoting full efficiency, however, still not immune to efficiency collapses. In a different environment with both fixed sunk and fixed avoidable costs, Durham et al. (2004), hereafter DMORS, examine the price levels under a SOA by varying the demand elasticity and the experience level of sellers. They observe the pattern of price signaling and responses which despite the presence of fixed costs help to maintain above normal profits. The authors do not comment on the efficiency performance of the auction or the magnitude of observed losses in the market.

All aforementioned studies model the market demand as static. This paper simulates a cyclical nature of the daily demand for electricity. Baltaduonis (2007b) points out that cyclical market demand might be essential in shaping strategic behavior in the COAs. As in Rassenti, Smith & Wilson (2003a, 2003b), hereafter RSW, my experiment allows for strategic behavior, controls for the level of unilateral market power, simulates trading environments with minimal demand elasticity, cyclical demand uncertainties and an absence of significant excess production capacity.

Concerns about market power in the electric power industry abound. One might want to know which trading rules are more effective in suppressing the exercise of market power. In the context of capacity-constrained competitors, Holt (1989) defines market power as the ability to deviate *profitably* and *unilaterally* from the competitive outcome. Baltaduonis (2007b) reports that both the OCM and the PCM auctions produce noncompetitive outcomes even in the treatments with no unilateral market power. Since the SOA reduces the scope of possible strategic behavior, I hypothesize that ceteris paribus, the SOA should increase competitiveness in the market. The COAs' intention to account for the non-convex cost structures of generation plants also opens opportunities to strategize over the different parameters of complex offers. The opportunities are fewer on that regard in the SOA. Baltaduonis finds that in the COAs, the offer complexity and the cyclical nature of market demand create incentives to start-up plants during the higher demand periods. Consequently, the incentives to compete for baseload or shoulder demand units vanish even with the presence of cheap excess production capacity. Opting for a SOA should eliminate these anti-competitive incentives.

An intention of this experimental study is to complement theoretical research of auctions where avoidable fixed costs are an important production characteristic. The study sheds some light on possible strategic behavior in smart markets that are proposed for wholesale electric power markets. The remainder of the paper is organized as follows. Section 2 outlines the market environment in the experiment and describes three auctions. Section 3 presents the experimental design and procedures. Section 4 reports the findings. Section 5 concludes and discusses the implications for public policy.

2 Market Institution, Structure and Environment

To isolate the institutional effects of the strategically complex auctions, I examine a very simple environment relative to actual electric power systems: (i) transmission constraints are negligible; (ii) generators have no physical ramping rates; (iii) security reserves and other ancillary services to protect the system from outages are ignored; and (iv) a trading institution accepts flat offer curves for each generating unit. Such an environment is most comparable to day-ahead wholesale markets of observed power systems. The performance of the SOA is measured against the OCM and the PCM auctions in a stationary supply and cyclical demand environment, controlling for unilateral market power.

2.1 Auction Institution

The sellers privately submit a schedule of offers; that is, plant start-up fees and prices for their production capacity for each pricing period of a day. The buyers submit a schedule of bids. Since active demand-side bidding is often absent in the naturally occurring spot markets for electricity, a computer is used to submit bids that perfectly reveal the demand at any point in time in the experiment[4]. The offers and the computerized bids are then sent to a market-clearing algorithm to allocate the production contracts for the next day. Currently, the dominant practice in the electricity spot markets is to employ uniform price auctions where each seller receives the same market price for the sold megawatts. The market price is usually the highest accepted price per megawatt among all the sellers. I retain these institutional features and put aside the discussion about the "pay-as-offered"

[4] Same as in RSW, DRSVW and DMORS.

discriminatory price auctions.[5] In all experimental treatments, i.e. OCM, PCM and SOA, the sellers get paid *uniform* prices and their *individual* start-up fees. In the SOA, the start-up fees are simply constrained to be zero.

In case of a uniform price auction where sellers ask for fixed start-up fees, the mechanism of distributing these fees across consumers is important. One way to do that is to divide the borne fees equally over the units dispatched during the period for which the extra generation capacity was called. The markup on the highest accepted offered price creates a gap between a uniform price that all sellers receive and a uniform price that all buyers pay. In this experiment, both the OCM and the PCM algorithms employ this method to compute the buyer prices and to determine the corresponding levels of demand. Note that a uniform price that all sellers receive and a uniform price that all buyers pay are the same in the SOA due to the absence of start-up fees.

2.1.1 The OCM Auction

The OCM algorithm minimizes the total offer costs of electricity, as if all selected sellers would be paid their offer prices and fees:

$$\underset{q_i(t),x_i(t)}{\mathrm{Min}} \sum_{t=1}^{T}\sum_{i=1}^{N}\left(c_i(t)q_i(t)+f_i(t)x_i(t)\right)$$

$$\begin{aligned}
\text{subject to } \sum_{j=1}^{M} d_j(t) &= \sum_{i=1}^{N} q_i(t) && \forall t=1,\ldots,T,\\
q_i(t) &\le x_i(t)k_i(t) && \forall i=1,\ldots,N,\\
q_i(t) &\ge x_i(t)l_i(t) && \forall i=1,\ldots,N,\\
x_i(t) &\in \{0,1\} && \forall i=1,\ldots,N.
\end{aligned}$$

[5] For experimental investigations of uniform price versus discriminatory price auctions SOAs see Mount, Schulze, Thomas & Zimmerman (2001), and Rassenti, Smith & Wilson (2003b).

where $i = 1,\dots,N$ indexes the generation plants;
$j = 1,\dots,M$ indexes the buyers;
$t = 1,\dots,T$ indicates the pricing periods during a day;

$$\text{Offers submitted by sellers:}\begin{cases} c_i(t) = \text{price per unit asked for plant } i; \\ f_i(t) = \text{start-up fee asked for plant } i; \\ k_i(t) = \text{max capacity of plant } i; \\ l_i(t) = \text{min capacity of plant } i; \end{cases}$$

$$\text{Decision variables:}\begin{cases} q_i(t) = \#\text{ units produced in plant } i; \\ x_i(t) = \begin{cases} 1 \text{ if plant } i \text{ is chosen to produce,} \\ 0 \text{ if plant } i \text{ is not chosen to produce.} \end{cases} \end{cases}$$

After the offers are selected, a uniform MCP is determined as the highest accepted price for each period *t*:

$$MCP(t) = \max\left\{c_i(t), \forall i \text{ such that } q_i(t) > 0\right\}.$$

All selected sellers receive their individual start-up fees and the uniform MCPs for the supplied electricity.

2.1.2 The PCM Auction

The PCM algorithm minimizes the actual procurement cost of electricity, *simultaneously* determining a MCP as the highest accepted price for each period *t*:

$$\underset{q_i(t),x_i(t)}{\text{Min}} \sum_{t=1}^{T}\sum_{i=1}^{N}\left(MCP(t)q_i(t) + f_i(t)x_i(t)\right)$$

$$\begin{aligned} \text{subject to } \sum_{j=1}^{M} d_j(t) &= \sum_{i=1}^{N} q_i(t) && \forall t = 1,\dots,T, \\ q_i(t) &\le x_i(t)k_i(t) && \forall i = 1,\dots,N, \\ q_i(t) &\ge x_i(t)l_i(t) && \forall i = 1,\dots,N, \\ x_i(t) &\in \{0,1\} && \forall i = 1,\dots,N. \end{aligned}$$

As in the OCM auction, the selected sellers receive their individual start-up fees and the uniform MCPs for the supplied electricity.

In the experiment, both the OCM and the PCM auctions are designed to sell the maximum amount of units where buyers' marginal willingness to pay is higher or equal to a buyer price. Tied offer combinations in the OCM auction are picked in a way that generates lower procurement cost. Tied offer combinations in the PCM auction are selected by giving priority to those sellers whose offer cost is lower. Such tie breaking mechanism gives the best performance chances to both COAs. To achieve similar tie breaking in real life applications would require additional costly computational power and time.

2.1.3 The Simple-Offer Auction

The sellers in the SOA can recover their production costs – both variable and avoidable fixed – only through a uniform MCP. Note that the SOA is a special case of the COAs, i.e. it is a COA where the start-up fees are constrained to be zero. The contract allocations in two COAs are identical when the start-up fees equal to zero. The offer cost minimization becomes equivalent to the payment cost minimization. Hence, either the OCM or the PCM algorithm could be used for the SOA by simply restricting all start-up fees to be zero, i.e. $f_i(t) = 0$ for $\forall i = 1,..., N$. The selected sellers receive the uniform MCPs for the supplied electricity.

In the complex-offer auctions, the suppliers are able to reveal their costs and be reimbursed in a way that the costs are incurred. In the SOA, the sellers have to think how to recover the fixed costs through the offered prices. See Appendix A for a simple numerical example that demonstrates the principles of offer-selection rules for all three considered auctions.

2.2 Environment

2.2.1 Supply & Demand

Each day in the experiment consists of four pricing periods: off peak period (low demand/night), shoulder period (medium demand/morning), peak period (high demand/ afternoon) and shoulder period (medium demand/ evening). Four pricing periods during the day are a simplification of the naturally occurring day-ahead electricity markets where separate prices are instituted hourly. Nevertheless, the cyclical dynamics of the demand are preserved.

Tables 1 and 2 as well as Fig. 1 depict aggregate supply and demand in the experimental environment. The second and third steps of the demand in Table 1 represent interruptible units of demand whereas the units on the first step at 250 are the "must serve" units. The level of "must serve" demand varied among three levels: 1 unit in off-peak periods, 4 units during shoulder periods, and 14 units during peak periods.

The market is comprised of six sellers denoted by an "*S*" and an identification number. The sellers own 13 plants of nine types. The technical characteristics of each plant are presented in Table 2. Fig. 1 presents the ownership of the plants. *S*1 and *S*2 own two low cost (type *A*) plants and two high cost plants (type *H* and *G* respectively). *S*3 and *S*4 own two high cost (type *E*) plants and respectively, one baseload (type *B*) plant and one intermediate cost (type *C*) plant. *S*4 also owns a very high cost (type *I*) peak capacity plant with average total cost (ATC) exceeding even the resale value at the "must serve" level. Each *S*5 and *S*6 own one intermediate cost (type *D*) plant and one high cost (type *G* and *F* respectively) peak capacity plant.

[a]Average total costs at the maximum capacity of a plant.

Fig. 1 Market Structure and Design

Table 1 Demand Schedules

Demand	Quantity (demand values)		
	Step 1	Step 2	Step 3
Off-peak	1 (250)	1 (80)	N/A
Shoulder	4 (250)	2 (230)	1 (160)
Peak	14 (250)	2 (230)	2 (160)

The types and the distribution of ownership of the plants are designed to create a Bertrand-like competition between the marginal plants during each period of a day. In other words, at least two plants with identical production costs on the supply margins exist for each level of demand. In a competitive bidding process, *S*1's plant *A* can be easily replaced by *S*2's plant *A* during an off-peak period and *S*5's plant *D* can be easily replaced by *S*6's plant *D* during the shoulder periods. Five plants with 10 units of total capacity and identical ATC compete to supply six units of peak demand. Some plants have low start-up costs with high production costs per unit, while other plants have high start-up costs but lower production costs per unit. In a competitive equilibrium, the number of supplied units is 2 in off-peak periods, 7 in shoulder periods and 16 in peak periods. The lower quantities of supplied units would be the evidence of allocative inefficiencies. Note that an efficient allocation of production contracts would never include *S*4's plant *I* and *S*1's plant *H*.

Table 2 Average Total Costs (ATC) of Production at Maximum Capacity (Cap.) by Plant Type

Plant Type	Min Cap.	Max Cap.	Start-up Cost	Per Unit Cost	ATC at Max Cap.	Total Cap.
(Quantity)	Units	Units	$	$/Unit	$/Unit	Units
A (2)	0	2	0	20	20	4
B (1)	1	1	10	15	25	1
C (1)	0	1	20	70	90	1
D (2)	0	2	6	93	96	4
E (2)	0	2	120	112	172	4
F (1)	0	2	80	132	172	2
G (2)	0	2	40	152	172	4
H (1)	0	2	0	225	225	2
I (1)	0	2	0	255	255	2
					Total	24

2.2.2 Unilateral Market Power

In the experiment, a seller is said to be able to exert market power if, for a given distribution of capacity ownership, a seller profitably and unilaterally can submit an offer schedule above his plants' costs (or equivalently withdraw some generating capacity) such that the market price rises above the competitive level.

The costs for the units in the marginal plants are 20, 99, 172 and 93 per unit in the off-peak, shoulder 1, peak and shoulder 2 periods respectively. In the SOA, these costs translate into the competitive market prices at which the marginal plants earn zero economic profits. None of the six sellers can benefit from a unilateral attempt to raise the market prices above the competitive level. In doing so, the sellers of intermediate units would jeopardize their profits and the sellers of marginal units would simply lose the contract to his Bertrand-like competitor. The competitive prices correspond to a pure strategy Nash equilibrium in the SOA.

In the COAs, the marginal generators also have incentives to submit offers that are equal to the actual production costs of the marginal units but only if we look at an isolated period of the demand cycle. The asked fees do not necessarily need to be the actual start-up costs but then the offered seller prices need to add up to the actual production costs. Consider the OCM auction for an illustration. Take a shoulder 1 period. Each *S*5 and *S*6 owns a marginal intermediate cost plant that competes to supply the marginal seventh unit to the market. Either plant can generate this marginal unit at a cost of 99 [6+93]. If a seller offers to supply the unit at a cost higher than 99, the other seller would be able to undercut the offer by either lowering the fixed fee or lowering the offered seller price. Therefore, a start-up fee and a price per unit would have to add up to 99 in a competitive offer of *S*5 or *S*6.

Similarly, the competitive marginal offers $[(\text{start-up fee} + \text{price per unit} \times 2) \div 2]$ would have to be 20 during the off-peak periods, 172 during the peak periods and 93 during the shoulder 2 periods.

This illustration disregards the incentives to withhold a plant's capacity during the lower demand periods due to the opportunities to extract bigger start-up fees during the higher demand periods. For instance, *S*6 can decide to delay the start-up of his plant by placing a high offer for shoulder 1 period. Assume that *S*6's peak offer is 340 for the start-up fee and 1 for price. This offer is still cheaper than the competitive offers of the peak plants for 172 per unit $\left(> \left(340 + 2 \times 1\right) \div 2\right)$. In this case, *S*6 makes a significant profit by abandoning competition in shoulder 1 period and by deliberately delaying the start-up of his plant *D* till the peak period. Consequently, *S*5 can now profitably raise her offer above her costs for shoulder 1 period as the competition from her Bertrand-like competitor *S*6 is absent. A competitive outcome becomes practically impossible. By allowing the sellers to submit complex-offers, the market mechanism automatically creates market power. This result holds for both the OCM and the PCM auctions. Note that the additional production capacity would not improve competitiveness in this environment because the suppliers of the additional capacity would have the same incentives to delay the start-ups.

The supply and demand are the same during the two shoulder periods of a day. However, since most plants are generating electricity during the peak period, they do not incur start-up costs and do not receive start-up fees to continue production during the shoulder 2 period, i.e. $f_i(\text{shoulder 2}) = 0 \quad \forall i$ such that $q_i(\text{peak}) > 0$. For this reason, all three examined auctions should perform similarly during the fourth period of a day.

Theoretically, none of the six sellers can benefit from a unilateral attempt to raise the MCP above 93. The competitive price of shoulder 2 corresponds to a pure strategy Nash equilibrium in all three auctions.

3 Experimental Design and Procedures

To compare how the behavior and market performance differ in the complex- and simple-offer auctions, I conducted 12 experimental sessions using undergraduate students at George Mason University. The data from eight sessions of the OCM and the PCM treatments was previously presented by Baltaduonis (2007b). The reported data from four SOA sessions is new. Each session lasted 53 trading days. The dataset discussed in this paper includes a total of 636 trading days. Each session lasted approximately 90 minutes. The subjects in each market were provided with complete information about the market supply structure. Plants' minimum and maximum production capacity, start-up cost, cost per unit and the ownership of all plants were public information. Information about demand, however, was not available to the subjects. The situation was framed as a market for identical product to avoid the use of possibly intimidating or confusing electric power jargon. The instructions informed the subjects that the costs and production capacities for each seller would not change during the experiment, but that the purchased quantities of the product would vary over the course of a day. In particular, the instructions indicated that the computer will purchase "low" amounts of product for the first quarter of a day, "medium" amounts for the second quarter of a day, "high" amounts for the third quarter of a day and "medium" amounts for the fourth quarter of a day. The subjects did not know the number of trading days in advance. The instructions were read aloud in the beginning of each session.

A subject had 75 seconds to submit an offer for each day.[6] An exception was made for the first day offers. The sellers could take as much time as they needed to formalize their initial offers. Once the last seller submitted her offer for the first day, the following trading days were limited to 75 seconds. The offers were automatically filled in with the offer information from the previous trading day. However, a seller could revise her offer at any time within the 75 second period. An offer indicated the prices, start-up fees and quantities of the product that a seller was willing to supply from a particular plant over the course of the following day. The subjects could not alter the minimum and maximum quantities of the offer.[7] These quantities were set equal to the minimum and maximum capacities of a plant. The subjects could still effectively withdraw the capacity from the market by asking extremely high prices for those capacity units. Thus, in a COA, a seller had to decide on the price and the start-up fee for each plant and for each quarter of the upcoming day.[8] In the SOA, a seller had to decide only on the price for each plant for each quarter of the upcoming day, as all start-up fees were set equal to zero. The instructions pointed out that the actual market price may be higher than their offered price and that all sellers would receive the same market price if their offers were selected. The sellers received start-up fees only for the periods when their plant had to be started. In the beginning of each day all plants were idle.

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[6] The chosen time frame is similar to one-minute trading days of the RSW electric power experiments and 75 s trading days of DMORS experiment.

[7] ISOs usually demand an explanation if generators change their offered generation capacity or technical constraints. Thus strategic behavior is somewhat limited with regards to these parameters of an offer.

[8] I am aware that there are various initiatives to regulate start-up cost reimbursement (e.g. limiting the ability to change the start-up fees freely; and partial start-up cost reimbursement) for electric power generators in naturally occurring markets. However, the purpose of the study is to investigate the performance of the two auctions when such interventions into a deregulated market are absent.

At the end of the trading day, all offers were sent to the computerized market coordinator. A market-clearing algorithm was applied and the results of a sealed-offer auction were sent back to the sellers. Each seller could see how many units she sold, what the MCP for each period was and what profit/loss she earned on every owned capacity unit during each period of a day. The screens also displayed a history of the market prices from the past 10 days and the sold quantities during each quarter of the last day. The amount of paid fees was not public information.[9]

Subjects were paid $7 for showing up on time for the sessions. In addition to this show-up payment, the average earnings per subject for the data reported here was $21.55.

4 Results

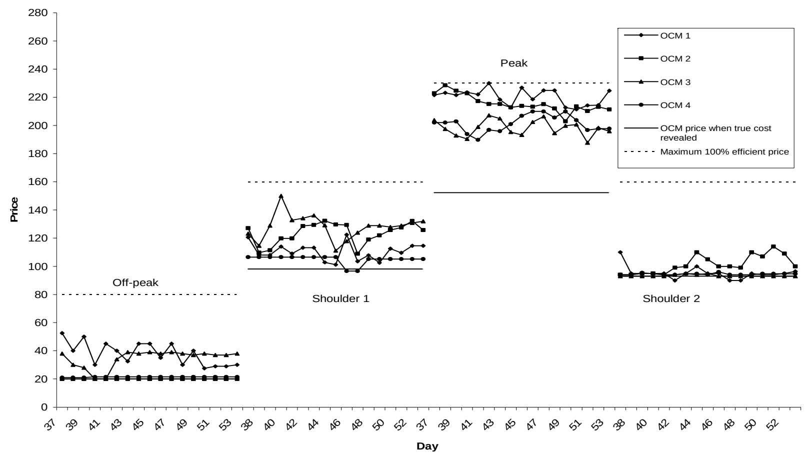
The SOA, OCM and PCM auctions respectively extract on average 93, 92 and 94 percent of maximum total surplus. All three auctions sell on average 32 units a day. Thus, considering that the demand side of the market is perfectly revealed in the experiment, lower levels of allocative efficiency must be attributed to higher degrees of production inefficiency. To present how the captured total surplus is allocated among buyers and sellers and how volatile the allocation is, Fig. 2 depicts the buyer prices in each session of the three treatments. The last 17 days of the data are grouped by level of demand (quarter) then sequenced by how the demand varied over a market day: off-peak, shoulder 1, peak and shoulder 2.

I evaluate the results with respect to a benchmark of true cost revelation. The outcome of true cost revelation is particularly interesting in electricity markets because the design

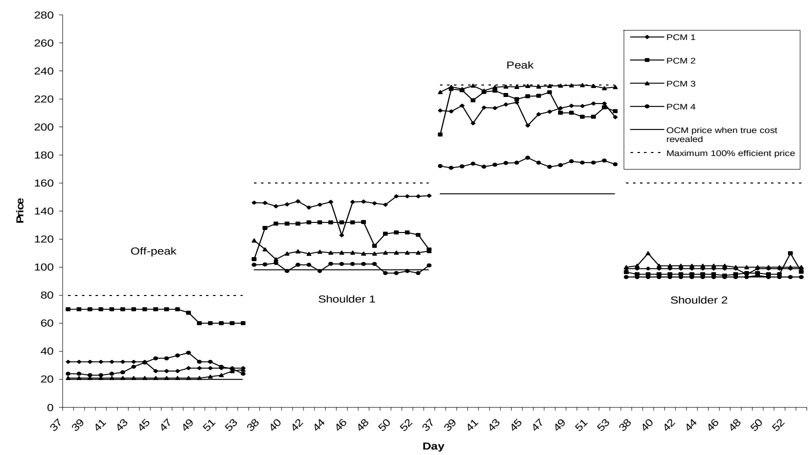
[9] See Appendix B for the experimental instructions and Appendix C for an example of a subject screen during the experiment.

and the engineering of these complicated market systems often start with the assumption of the true cost revelation. In Fig. 2, the outcome of the perfectly revealed costs is shown as a solid line. The dotted line represents the value of the nearest unit of interruptible demand. The prices up to the dotted line are 100% efficient with respect to allocation. As an attempt to control for the convergence of the bidding behavior, I focus on the last 17 market days (1/3 of all days) in each session unless referred otherwise.

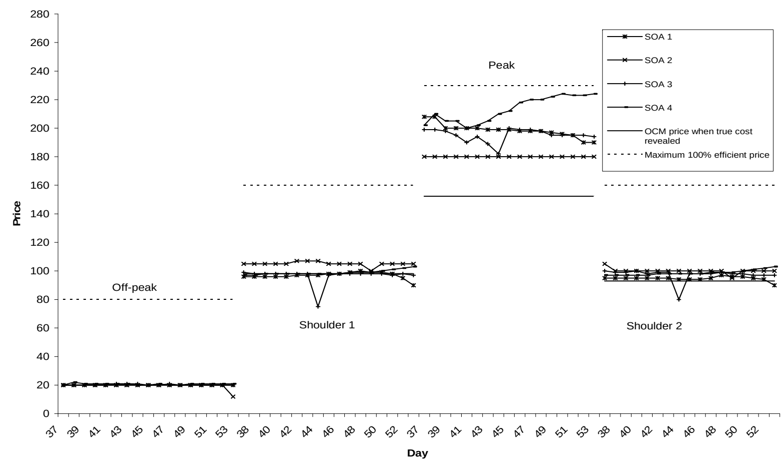
In Fig. 2, the SOA is more likely to approach the true cost revelation outcome than either of the two COAs. Both the OCM and the PCM auctions tend to deviate significantly from the outcome of perfectly revealed costs with shoulder 2 periods being an exception. In the SOA, the buyer prices substantially depart from the competitive outcome only during the peak periods. During shoulder 2 periods, all three auctions result in competitive outcomes. The conformity is not accidental since the fixed costs are absent in this period and, therefore, all three offer selection rules are identical as the start-up fees equal to zero.



(a) OCM



(b) PCM



(c) SOA

Fig. 2 Buyer Prices by Level of Demand for the Last 17 Market Days in Each Session

In what follows, the experimental results are summarized as a series of six findings. In addition to the qualitative results displayed in the figures, I analyze the data using a mixed-effects model for repeated measures on each of several sessions using different subjects. The results from estimating this model for the buyer prices by level of demand are given in Table 3. The dependent variable in this case is the difference between the observed buyer price (*Price*) and the buyer price from the OCM auction when production costs are perfectly revealed by the sellers, P^t. In the regressions, the SOA is used as a benchmark institution to allow for its straightforward comparison against the OCM and the PCM auctions. The treatment effects (*OCM* and *PCM*) are modeled as (zero-one) fixed effects, whereas the sessions are modeled as random effects, e_i. As mentioned above, the experimental days are divided into three equal groups to capture effects like learning over time. In the model, the data from the *First* and *Second* groups (days 1-18 and 19-36, respectively) are identified by (zero-one) dummy variables. Specifically, the estimated model is as follows:

$$Price_{ij}\text{-}P^t=\mu+e_i+\beta_1 OCM_i+\beta_2 PCM_i+\beta_3 First_i+\beta_4 Second_i+\beta_5 OCM_i\times First_i+$$
$$\beta_6 OCM_i\times Second_i+\beta_7 PCM_i\times First_i+\beta_8 PCM_i\times Second_i+\varepsilon_{ij};$$

where the sessions are indexed by i=1,…,12 and the repeated market days by j=1,…,53. $e_i \sim N(0,\sigma^2{}_1)$ and $\varepsilon_{ij} \sim N(0,\sigma^2{}_{2,i})$.

Finding 1. *Ceteris paribus, the SOA institution significantly lowers buyer prices relative to the COAs in the periods when start-up costs are relevant. Buyer prices are not significantly different in shoulder 2 periods when no new plants need to be started and no start-up fees need to be paid.*

Support: Fig. 2 clearly illustrates that both the OCM and the PCM auctions can produce higher buyer prices than the SOA in all three periods where new plants need to be started, that is, in off-peak, shoulder 1 and peak periods. Except for peak periods, buyer prices in the SOA settle very close to the competitive equilibrium, i.e. 20, 99, 172 and 93, during the respective quarters of a day. SOA prices for peak periods do not come close to the expected competitive level of 172. My speculation is that the incentives to undercut the competitors' offers are weaker in the peak periods because winning a marginal contract and setting a lower uniform market price also means smaller profits for the low or/and intermediate cost plants that the seller owns. On the other hand, no discernible separation exists among three auctions in shoulder 2 prices. Since most of the plants are operating during the peak periods, no new plants need to be started when market demand falls. The absence of start-up fees makes the three offer selection rules identical which consequently should lead to similar outcomes.

These qualitative observations are supported by estimates from the mixed-effects model in Table 3. The SOA significantly reduces prices by 19.5 (*p-value*=0.0077) and 17 (*p-value*=0.0744) experimental dollars in the shoulder 1 and peak periods when compared to the OCM auction. The SOA significantly reduces prices by 18.2 (*p-value*=0.0417), 17.4 (*p-value*=0.0127) and 20 (*p-value*=0.0418) experimental dollars respectively in the off-peak, shoulder 1 and peak periods when compared to the PCM auction. The prices in shoulder 2 periods are not significantly different across all three auctions (*p-values*=0.1615, 0.4404 for OCM and PCM, respectively).■

Table 3 Estimates of the Linear Mixed Effects Model of Treatment Effects for the Buyer Prices

$$Price_{ij} - P^t = \mu + e_i + \beta_1 OCM_i + \beta_2 PCM_i + \beta_3 First_i + \beta_4 Second_i + \beta_5 OCM_i \times First_i + \beta_6 OCM_i \times Second_i + \beta_7 PCM_i \times First_i + \beta_8 PCM_i \times Second_i + \varepsilon_{ij},\ \ e_i \sim N(0,\sigma^2_1) \text{ and } \varepsilon_{ij} \sim N(0,\sigma^2_{2,i})$$

	Estimate	Std. Error	Degrees of Freedom	H_a	t-statistic	p-value
Off-peak						
μ	**-1.21**	**5.41**	**618**	**μ>0**	**-0.22**	**0.8227**
OCM	**8.58**	**7.70**	**9**	**$\beta_1 \neq 0$**	**1.12**	**0.2935**
PCM	**18.23**	**7.68**	**9**	**$\beta_2 \neq 0$**	**2.37**	**0.0417**
First	-1.66	0.40	618	$\beta_3 \neq 0$	-4.19	<.0001
Second	-0.36	0.40	618	$\beta_4 \neq 0$	-0.92	0.3584
OCM×First	-5.06	1.28	618	$\beta_5 \neq 0$	-3.95	0.0001
OCM×Second	-2.35	1.28	618	$\beta_6 \neq 0$	-1.84	0.0669
PCM×First	-0.81	0.89	618	$\beta_7 \neq 0$	-0.90	0.3664
PCM×Second	-1.31	0.89	618	$\beta_8 \neq 0$	-1.47	0.1434
Shoulder 1						
μ	**-1.13**	**3.99**	**618**	**μ>0**	**-0.28**	**0.7771**
OCM	**19.53**	**5.71**	**9**	**$\beta_1 \neq 0$**	**3.42**	**0.0077**
PCM	**17.36**	**5.60**	**9**	**$\beta_2 \neq 0$**	**3.10**	**0.0127**
First	-9.02	1.80	618	$\beta_3 \neq 0$	-5.02	<.0001
Second	1.96	1.80	618	$\beta_4 \neq 0$	1.09	0.2760
OCM×First	1.05	2.82	618	$\beta_5 \neq 0$	0.37	0.7102
OCM×Second	-3.57	2.82	618	$\beta_6 \neq 0$	-1.27	0.2054
PCM×First	16.74	2.11	618	$\beta_7 \neq 0$	7.93	<.0001
PCM×Second	-0.31	2.11	618	$\beta_8 \neq 0$	-0.15	0.8832
Peak						
μ	**40.15**	**5.98**	**618**	**μ>0**	**6.71**	**<.0001**
OCM	**17.02**	**8.44**	**9**	**$\beta_2 \neq 0$**	**2.02**	**0.0744**
PCM	**19.98**	**8.43**	**9**	**$\beta_2 \neq 0$**	**2.37**	**0.0418**
First	9.25	1.82	618	$\beta_3 \neq 0$	5.09	<.0001
Second	2.88	1.82	618	$\beta_4 \neq 0$	1.58	0.1137
OCM×First	-11.42	2.59	618	$\beta_7 \neq 0$	-4.41	<.0001
OCM×Second	1.47	2.59	618	$\beta_8 \neq 0$	0.57	0.5710
PCM×First	-17.87	2.48	618	$\beta_7 \neq 0$	-7.21	<.0001
PCM×Second	-6.24	2.48	618	$\beta_8 \neq 0$	-2.52	0.0121
Shoulder 2						
μ	**3.12**	**1.18**	**618**	**μ>0**	**2.65**	**0.0083**
OCM	**-2.29**	**1.50**	**9**	**$\beta_2 \neq 0$**	**-1.53**	**0.1615**
PCM	**-1.31**	**1.62**	**9**	**$\beta_2 \neq 0$**	**-0.81**	**0.4404**
First	-0.44	1.12	618	$\beta_3 \neq 0$	-0.40	0.6924
Second	2.29	1.12	618	$\beta_4 \neq 0$	2.04	0.0415
OCM×First	-0.07	1.16	618	$\beta_7 \neq 0$	-0.06	0.9539
OCM×Second	-2.61	1.16	618	$\beta_8 \neq 0$	-2.25	0.0248
PCM×First	10.87	1.65	618	$\beta_7 \neq 0$	6.57	<.0001
PCM×Second	1.07	1.65	618	$\beta_8 \neq 0$	0.65	0.5191

Note. The linear mixed-effects model is fit by maximum likelihood with 636 original observations and 12 sessions. For purposes of the brevity the session random effects are not included in the table.

Finding 2: *Ceteris paribus, markets in the SOA treatment quickly stabilize at the competitive equilibrium quantity at all levels of demand, whereas the COAs continue to interrupt market demand throughout the experiment, especially during the peak periods.*

Support: On only 18 occasions (out of possible 848 = 53 days × 4 quarters × 4 sessions) the SOA exchanged an allocative inefficient quantity. 17 of these occasions happened during the peak periods. The last inefficient allocation was observed during the twelfth trading day in session 2. The OCM (PCM) auction experienced 55 (24) allocative inefficient exchanges, with the latest observation being during the 44th (53rd) trading day. 44 (19) or 80% (79%) of these inefficient exchanges happened during the peak periods. In Fig. 2, the last 17 days in all sessions resulted in 100% efficient buyer prices. However, this does not necessarily mean that all OCM sessions supplied the efficient quantity to the market during all those days. In fact, the demand had to be interrupted on five occasions (out of possible 272 = 17 days × 4 quarters × 4 sessions), because the price for the efficient amount exceeded buyers' maximum willingness to pay. Similarly, the demand was interrupted on four occasions in the PCM sessions.■

Failure to supply the efficient amount of units is not the only source of possible inefficiencies. The total surplus might also be reduced by production inefficiencies, i.e. the situations when higher cost plants produce while lower cost plants are idle.

Finding 3: *Ceteris paribus, the COA and SOA treatments exhibit similar degrees of production inefficiency.*

Support: Fig. 3, the estimates from the mixed-effects model in Table 4 and the statistics of the non-parametric Mann-Whitney U test in Table 5[10] report evidence that in all periods, the COA and SOA treatments are not significantly different from each other. The dependent variable in the mixed-effects model is the difference between the observed production cost (*ProdCost*) and the minimum production cost for the exchanged quantity, $ProdCost^{*}$.[11] The treatment effects are insignificant for all periods[12].

Some of the production inefficiencies in the COAs stem from frequent occasions when the very high cost generators of H and I types are called to produce. The owners of the most inefficient plants (type H and I) are able to win contracts and profitably supply to the market by offering low prices and recovering their variable costs through high start-up fees. During the last 17 days of the OCM sessions, these plants are selected and make positive profits during 42 days [out of possible 68 = 17days× 4sessions]. The same plants sell profitably during six days in the PCM sessions and never in the SOA.■

Since the deregulation of electricity markets, inflated and volatile wholesale electricity prices have been a concern.

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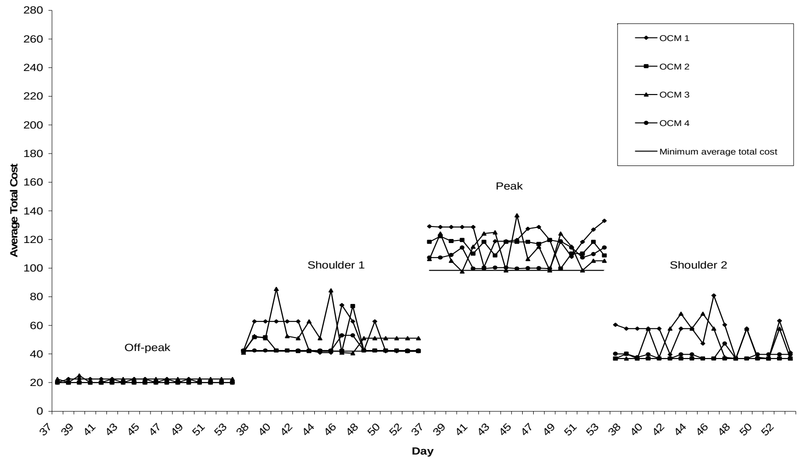
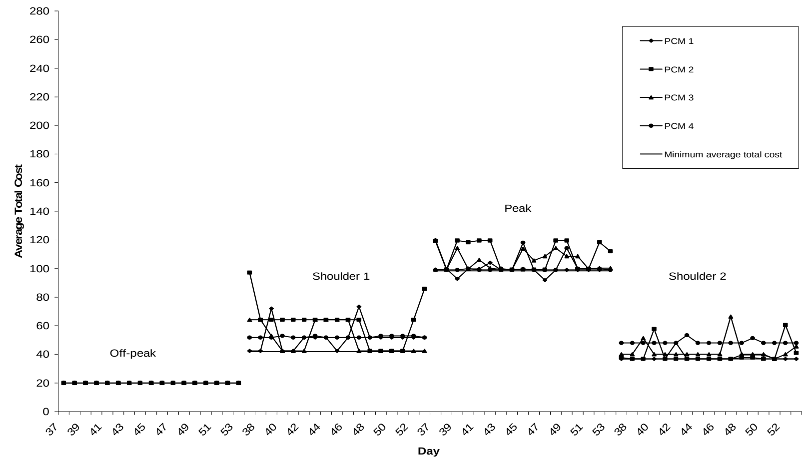
[10] Due to the lack of normality in the distribution of the estimated errors for the linear mixed effects model, I also applied the non-parametric Mann-Whitney U test to the average production costs for the last 17 market days.

[11] An interpretation of the regression results might be problematic if the exchanged quantity fluctuates across the days. However, this problem does not arise here since during the last 17 days of the experiment, the demand had to be interrupted only on 5 occasions (out of possible 272 = 17 days × 4 quarters × 4 sessions) in the OCM treatment, and on 4 occasions in the PCM treatment.

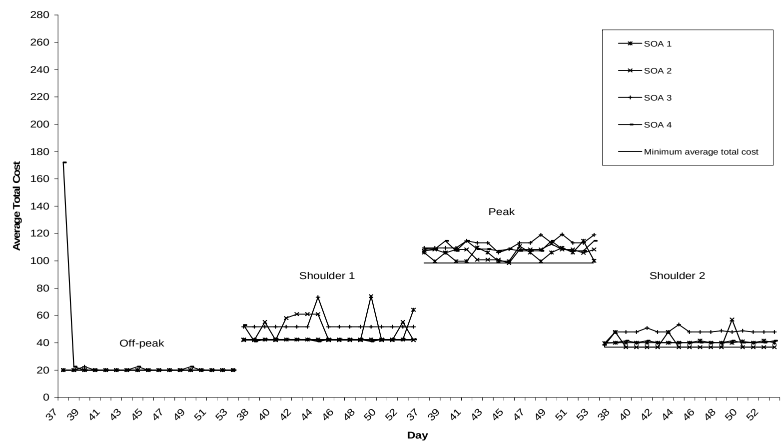
[12] The estimated mixed-effects model suggests that in peak periods, the SOA treatment raises production costs above the PCM level by 83.3 experimental dollars (*p-value*=0.0298); on the other hand, the Mann-Whitney U test finds this difference in costs statistically insignificant (*p-value*=0.1143).



(a) OCM



(b) PCM



(c) SOA

Fig. 3 Average Total Costs by Level of Demand for the Last 17 Market Days in Each Session

Table 4 Estimates of the Linear Mixed Effects Model of Treatment Effects for the Production Costs

$$ProdCost_{ij} - ProdCost^{*} = \mu + e_i + \beta_1 OCM_i + \beta_2 PCM_i + \beta_3 First_i + \beta_4 Second_i + \beta_5 OCM_i \times First_i + \beta_6 OCM_i \times Second_i + \beta_7 PCM_i \times First_i + \beta_8 PCM_i \times Second_i + \varepsilon_{ij},$$
$$e_i \sim N(0,\sigma^2_{1}) \text{ and } \varepsilon_{ij} \sim N(0,\sigma^2_{2,i})$$

	Estimate	Std. Error	Degrees of Freedom	H_a	t-statistic	p-value
Off-peak						
Due to the lack of variability of the dependent variable, the model cannot be estimated for the off-peak periods. Treatment averages and standard deviations are presented instead.						
	Average	Std. Dev.				
SOA	**4.76**	**36.85**				
OCM	**1.69**	**2.38**				
PCM	**0.00**	**0.00**				
Shoulder 1						
μ	**47.96**	**17.63**	**618**	**$\mu>0$**	**2.72**	**0.0067**
OCM	**-10.94**	**24.92**	**9**	**$\beta_2\neq0$**	**-0.44**	**0.6711**
PCM	**31.44**	**24.92**	**9**	**$\beta_2\neq0$**	**1.26**	**0.2389**
First	120.28	14.75	618	$\beta_3\neq0$	8.15	<.0001
Second	5.71	14.75	618	$\beta_4\neq0$	0.39	0.6986
OCM×First	-6.28	21.04	618	$\beta_7\neq0$	-0.30	0.7653
OCM×Second	31.00	21.04	618	$\beta_8\neq0$	1.47	0.1412
PCM×First	-64.65	20.70	618	$\beta_7\neq0$	-3.12	0.0019
PCM×Second	18.45	20.70	618	$\beta_8\neq0$	0.89	0.3731
Peak						
μ	**165.52**	**21.61**	**618**	**$\mu>0$**	**7.66**	**<.0001**
OCM	**57.34**	**33.18**	**9**	**$\beta_2\neq0$**	**1.73**	**0.1180**
PCM	**-83.30**	**32.32**	**9**	**$\beta_2\neq0$**	**-2.58**	**0.0298**
First	-18.28	16.70	618	$\beta_3\neq0$	-1.09	0.2742
Second	-15.04	16.70	618	$\beta_4\neq0$	-0.90	0.3683
OCM×First	-47.65	29.11	618	$\beta_7\neq0$	-1.64	0.1022
OCM×Second	-35.60	29.11	618	$\beta_8\neq0$	-1.22	0.2218
PCM×First	72.55	27.92	618	$\beta_7\neq0$	2.60	0.0096
PCM×Second	61.60	27.92	618	$\beta_8\neq0$	2.21	0.0277
Shoulder 2						
μ	**58.95**	**18.92**	**618**	**$\mu>0$**	**3.11**	**0.0019**
OCM	**-13.81**	**26.98**	**9**	**$\beta_2\neq0$**	**-0.51**	**0.6208**
PCM	**-17.44**	**26.66**	**9**	**$\beta_2\neq0$**	**-0.65**	**0.5293**
First	65.63	10.53	618	$\beta_3\neq0$	6.23	<.0001
Second	7.68	10.53	618	$\beta_4\neq0$	0.73	0.4663
OCM×First	51.16	16.11	618	$\beta_7\neq0$	3.18	0.0016
OCM×Second	21.09	16.11	618	$\beta_8\neq0$	1.31	0.1912
PCM×First	-4.42	16.06	618	$\beta_7\neq0$	-0.28	0.7830
PCM×Second	6.40	16.06	618	$\beta_8\neq0$	0.40	0.6903

Note. The linear mixed-effects model is fit by maximum likelihood with 636 original observations and 12 sessions. For purposes of the brevity the session random effects are not included in the table.

Finding 4: *Ceteris paribus, the variance of buyer prices in the SOA is same or lower than in the COAs.*

Table 5 Mann-Whitney U test on the Average Total Production Costs for the Last 17 Market Days

Period	SOA vs. OCM		SOA vs. PCM	
	$U_{4,4}$	p (two-tailed)	$U_{4,4}$	p (two-tailed)
Off peak	8	1.0000	12	0.3429
Shoulder 1	10	0.6857	13	0.2000
Peak	12	0.3429	14	0.1143
Shoulder 2	8	1.0000	8	1.0000

Support: Fig. 2 presents the dynamics of buyer prices in the auctions. Fig. 4 provides averages of the price variances for the 12 sessions presented here. Table 6 summarizes the results of the Mann-Whitney U test comparing the variances of the COAs against the variances of the SOA. The evidence suggests that in all periods the SOA attains at least as low volatility of prices as the COAs. Price volatility is significantly higher in shoulder 1 periods of the OCM auction (*p-value*=0.0571) and off-peak periods of the PCM auction (*p-value*=0.0571).■

Table 6 Mann-Whitney U test on the Buyer Price Variances for the Last 17 Market Days

Period	SOA vs. OCM		SOA vs. PCM	
	$U_{4,4}$	p (two-tailed)	$U_{4,4}$	p (two-tailed)
Off peak	9.5	0.6857	15	0.0571
Shoulder 1	15	0.0571	14	0.1143
Peak	12	0.3429	9	0.8857
Shoulder 2	9	0.8857	10	0.6857

Fig. 4 Buyer Price Variances by Treatment for the Last 17 Market Days

The above findings implicate that the SOA outperforms the COAs with respect to allocative efficiency, buyer prices and price volatility. On the other hand, a concern was raised that the SOA might increase a risk of short-term losses to the sellers. Finding 5 addresses this issue.

Finding 5: *Ceteris paribus, plants experience more short-term losses in the SOA than in the COAs; however, the relative size of occasional losses compared to accumulated profits is small.*

Support: The total amounts of experienced losses in the OCM, PCM and SOA sessions are respectively 24346, 11679 and 38192 experimental dollars. The losses substantially decline towards the end of the sessions. The amounts of losses during the last 17 days of the experiment are respectively 562, 973 and 1966 experimental dollars. These losses represent 0.3, 0.6 and 1.3 percent of market profits. Fig. 5 summarizes the total amounts of experienced losses by quarter of the day. Table 7 presents the results of the Mann-Whitney U test comparing the losses of the SOA against the COAs. One-tailed tests suggests that the SOA accumulates significantly higher losses than the COAs during the off-peak and shoulder 1 periods (*p-values*=0.0571). The differences during the peak and shoulder 2 periods are statistically insignificant.[13]■

[13] Interestingly, the amount of experienced losses in the SOA are almost perfectly correlated with the efficiency levels of the plants. The plants that are more costly are more likely to experience bigger short-term losses.

Fig. 5 Total Losses by Treatment for the Last 17 Market Days

Table 7 Mann-Whitney U test on the Total Experienced Losses for the Last 17 Market Days

	SOA vs. OCM		SOA vs. PCM	
Period	$U_{4,4}$	p (one-tailed)	$U_{4,4}$	p (one-tailed)
Off peak	14	0.0571	14	0.0571
Shoulder 1	14	0.0571	12	0.1714
Peak	10	0.3429	8	0.5571
Shoulder 2	9	0.4429	9	0.4429

Finding 6: *Ceteris paribus, outcomes in the SOA are more competitive than in the COAs during the periods when avoidable fixed costs are relevant.*

Support: The SOA always transacts competitive equilibrium amounts while as mentioned above, two COAs come short on number occasions especially during peak periods. Buyer prices in the SOA are significantly lower than the prices in two COAs (Finding 1). Average economic profits of the marginal plants are lower in the SOA than in two COAs during all but shoulder 2 periods (Fig. 6). The Mann-Whitney U test suggests that differences are significant during off-peak, shoulder 1 and peak periods (Table 8: one-tailed *p-values*=0.0571, 0.0286 and

0.0286 respectively for the OCM auction; *p-values*=0.0143 and 0.0571 for off-peak and peak periods in the PCM auction).■

Fig. 6 Average Profits of Marginal Plants by Treatment for the Last 17 Market Days

Table 8 Mann-Whitney U test on Average Profits of Marginal Plants for the Last 17 Market Days

	SOA vs. OCM		SOA vs. PCM	
Period	$U_{4,4}$	p (one-tailed)	$U_{4,4}$	p (one-tailed)
Off peak	13.5	0.0571	16	0.0143
Shoulder 1	15	0.0286	12	0.1714
Peak	15	0.0286	14	0.0571
Shoulder 2	13	0.9000	10	0.6571

5 Conclusions

In a dynamic trading environment that models wholesale electric power markets, the SOA reduces prices to consumers, lowers price volatility and achieves allocative efficiency more quickly than either of two COAs. These gains come at the cost of higher risk of short term losses. The short term losses, however, are rather small relative to the accumulated profits in the described environment.

A frequent critique is if we can learn anything about complex electric power markets from the undergraduates submitting offers in a computer laboratory over the course of 90 minutes. As Fig. 2 shows, prices collapse to the competitive levels in the SOA. The so-called unprofessional undergraduates leave no room for professional commodity traders to be more competitive. On the other hand, the groups of random students in the COAs succeed in raising prices to levels observed in an environment with structural market power. Hence, undergraduates with no professional experience to a COA mechanism extract almost maximum profits during a 90 minute period of trading. The competitive forces are clearly weaker in two COAs relative to the SOA.

The SOA has less room for strategic behavior. Consequently, the SOA is able to mitigate anti-competitive effects that are present in the COAs, such as the incentive to withhold the lower cost production capacity for the higher demand periods and the ability to sell higher cost units by manipulating the combination of offered fees and prices. It seems that two noteworthy forces exist affecting the performance of COAs. First, the incentive to compete in a COA is weak. And second, a difficulty exists in identifying what offers could displace the offers of competitors since the information about relative structure of two-part priced offers is not public. Shoulder 2 periods are a good example how simpler and more transparent these markets could be if avoidable fixed costs did not exist. The outcomes are relatively competitive in all three auctions since most plants are not eligible for start-up fees in shoulder 2 periods. It is clear that allowing the sellers to recover their variable and avoidable fixed costs separately does not enhance the transparency and competition in the market.

These results implicate that auctions which adopt non-convex optimization mechanisms might be neither necessary nor constructive remedy dealing with non-convex production technologies. After all, many industries with fixed costs successfully operate in the competitive markets with price-per-quantity trades.

For policy makers the lesson is clear: keep market institutions simple. Allowing market participants to reveal more information and trying to make use of that information also creates more opportunities to act strategically. If a way to strike it rich exists within the institutional rules of trading, the market participants find it.

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Appendix A An Example of a Simple Wholesale Electricity Market

To highlight the differences of the market-clearing rules in question, consider a three-supplier market examined by Knoblauch (2005) and Baltaduonis (2007a). Say we have an electricity market for one hour. The demand is inelastic and equal to 2 units. Supplier 1 (*S*1) and Supplier 2 (*S*2) are identical. They incur 6 dollars of fixed costs to start up their plants and 93 dollars of variable costs to generate one unit of electricity. Each of them can supply 0, 1 or 2 units of electricity. Supplier 3 (*S*3) has start-up cost of 20 dollars and variable cost of 70 dollars per unit. She can supply 0 or 1 unit of electricity.

For the purpose of this example suppose that all suppliers submit offers that reflect their true production costs. Since the fees are constrained to be zero in the SOA, the suppliers would incur losses unless they recover their fixed costs through the prices. Therefore, in the SOA, the fixed cost can be evenly distributed over the variable cost at the full capacity level of a plant. In this case, *S*1 and *S*2 would submit offers of 96 (=93+6÷2) dollars per unit and *S*3 would submit an offer of 90 (=70+20) dollars per unit. Given these offers the three auctions would generate the following outcomes.

A.1 The OCM Auction

The OCM algorithm minimizes the total offered cost of electricity, as if all selected sellers would be paid their offered prices and fees. Given the offers, an ISO calculates the minimum offered cost in two cases: 1) buying two units from $S1(S2)$ or 2) buying one unit from $S3$ and one unit from $S1(S2)$:

$$\text{Min}\{Price_{1,2}\times 2+Fee_{1,2}\ ,\ Price_{3}+Fee_{3}+Price_{1,2}+Fee_{1,2}\},$$

$$\text{Min}\{93\times 2+6,\ 70+20+93+6\}=70+20+93+6=189.$$

The auction chooses to buy 1 unit from $S3$ and 1 unit from $S1(S2)$. After the offers are selected, a uniform MCP is determined as the highest accepted price for that period; the MCP is 93 (=max{70, 93}). All selected sellers receive their individual start-up fees and the uniform MCP for the supplied electricity during that period; the total procurement cost of electricity is 212 (=93×2+20+6). The uniform market price that all buyers pay is 106 [=93+(20+6)÷2)]. Notice that this contract allocation is production efficient since no way exists to generate two units of electricity cheaper than the chosen suppliers do.

A.2 The PCM Auction

The PCM algorithm minimizes the actual procurement cost of electricity, simultaneously determining a MCP as the highest accepted price during that period. An ISO calculates the minimum procurement cost in two cases: 1) buying two units from $S1(S2)$ or 2) buying one unit from $S3$ and one unit from $S1(S2)$:

$$\text{Min}\{Price_{1,2}\times 2+Fee_{1,2}\ ,\ \max\{Price_{3}\ ,\ Price_{1,2}\}\times 2+Fee_{3}+Fee_{1,2}\},$$

$$\text{Min}\{93\times 2+6,\ \max\{70,\ 93\}\times 2+20+6\}=93\times 2+6=192.$$

The auction chooses to buy two units from $S1(S2)$. The MCP is 93. As in the OCM auction, the selected sellers receive their individual start-up fees and the uniform MCP for the supplied electricity. Both the total procurement cost and the total production cost are equal to 192 (=93×2+6). The market price for buyers is 96 (=93+6÷2). This contract allocation is not production efficient since $S3$'s plant with relatively lower average total cost is idle.

A.3 The Simple-Offer Auction

The sellers can recover their production costs – both variable and avoidable fixed – only through a uniform MCP in the SOA. Notice that the SOA is a COA where the start-up fees are constrained to be zero. The contract allocations in two COAs are identical when the start-up fees equal zero. Hence, either the OCM or the PCM algorithm could be used for the SOA by simply restricting all start-up fees to zero. In the discussed example, an ISO considers two options: 1) buying two units from $S1(S2)$ or 2) buying one unit from $S3$ and one unit from $S1(S2)$:

$$\mathrm{Min}\{Price_{1,2}\times 2\ ,\ Price_3+Price_{1,2}\},$$

$$\mathrm{Min}\{96\times 2,\ 90+96\}=90+96=186.$$

The auction chooses to buy 1 unit from $S3$ and 1 unit from $S1(S2)$. The MCP is 96. The selected sellers receive the uniform MCP for the supplied electricity. The total procurement cost of electricity is equal to 192 (=96×2). This contract allocation is production efficient, since no way exists to generate two units of electricity cheaper than the chosen suppliers do. However, this outcome is problematic because $S1(S2)$ is not able to recover all production costs and incurs a loss of -3 (=96-93-6). Since this outcome can not be sustained in the long run, $S1(S2)$ would be forced to increase the offer in order to recover the fixed cost even when she sells only one unit of energy. The minimum sustainable offer is 99 dollars per unit. In this case, the outcome is as follows:

$$\text{Min}\{99\times 2, 90+99\}=90+99=189.$$

The auction chooses to buy one unit from $S3$ and one unit from $S1(S2)$. The MCP for both buyers and sellers is 99. The total procurement cost of electricity is equal to 198 (=99×2). The contract allocation is production efficient.

In the presented example, given the assumption of truthful production cost revelation, the PCM auction produces the lowest procurement cost of electricity. It slightly outperforms the SOA and more significantly the OCM auction. On the other hand, the PCM auction is the only one to yield a production inefficient allocation. The SOA case shows that the sellers might face a risk of short-term losses.

Appendix B Experimental Instructions

<page 1>

Welcome

This is an experiment in the economics of decision-making. If you read the instructions carefully and make good decisions, you may earn a considerable amount of money that will be paid to you in CASH at the end of the experiment.

The experiment will take place through the computer terminals at which you are seated. If you have any questions at any time, please raise your hand and a monitor will come to assist you.

In this experiment, owners of plants sell an identical product to a computer buyer every day. Each day lasts 75 seconds. You are an **owner** of #yourNumberOfPlants# plants. There are #numberOfSellers# sellers and #numberOfPlants# plants including yours. Each seller owns between 1 and 4 plants.

<page 2>

Each day is divided into 4 quarters. Each quarter is represented by a line in the table at the top of your screen. The computer will purchase varying quantities of the product over the course of a day: Low, Medium, High and Medium amounts.

Sellers submit offers to sell. An offer indicates the prices and quantities of the product that you are willing to sell during the course of the following day. All quantities are measured in number of units.

<page 3 OCM and PCM>

You as a seller are able to decide:

Price/unit is the price per unit you are willing to sell at during that quarter from that plant. This is the minimum price at which you are willing to sell. The actual market price may be higher depending on the demand of the product. Each seller receives the same market price for sold units during the quarter. The market price is the highest accepted Price/unit among all of the sellers. If you sell the product you also incur a cost per unit sold. This cost is listed on the right side under the table and must be paid for each unit you sell.

Start-Up Fee is a fee that is paid to you for turning on your plant. The fee is paid to you only if the plant was not operating during the previous quarter. When your plant is turned on, you also must pay the start-up cost, which is listed on the right side under the table.

You will be able to make this decision for each quarter of the upcoming day for each plant that you have.

<page 3 SOA>

You as a seller are able to decide:

Price/unit is the price per unit you are willing to sell at during that quarter from that plant. This is the minimum price at which you are willing to sell. The actual market price may be higher depending on the demand of the product. Each seller receives the same market price for sold units during the quarter. The market price is the highest accepted Price/unit among all of the sellers. If you sell the product you also incur a cost per unit sold. This cost is listed on the right side under the table and must be paid for each unit you sell.

You will be able to make this decision for each quarter of the upcoming day for each plant that you have.

<page 4 OCM and PCM>

To switch between plants click on the tabs at the top of your screen. To enter the values select the appropriate cell in the table and double click.

Some offer values are automatically filled in for you:

Min Qty is the minimum number of units you are willing to sell during that quarter from that plant. Min Qty must be ≥ Minimum Capacity, which is specified under the table. This will be filled with that plant's Minimum Capacity.

Max Qty is the maximum number of units you are willing to sell during that quarter from that plant. Max Qty must be ≤ Maximum Capacity, which is specified under the table. Max Qty must also be ≥ Min Qty. This will be filled with that plant's Maximum Capacity.

<page 4 SOA>

To switch between plants click on the tabs at the top of your screen. To enter the values select the appropriate cell in the table and double click.

Some offer values are automatically filled in for you:

Min Qty is the minimum number of units you are willing to sell during that quarter from that plant. Min Qty must be ≥ Minimum Capacity, which is specified under the table. This will be filled with that plant's Minimum Capacity.

Max Qty is the maximum number of units you are willing to sell during that quarter from that plant. Max Qty must be ≤ Maximum Capacity, which is specified under the table. Max Qty must also be ≥ Min Qty. This will be filled with that plant's Maximum Capacity.

When your plant is turned on, you also must pay the start-up cost, which is listed on the right side under the table. You will not receive the **Start-Up Fee** for turning on your plant.

<page 5 PCM>

Offers are sent to the computerized market coordinator when you click the Submit button or when the day is over. Your offer from the previous day will be automatically submitted for you if you choose not to make any changes during the course of a day.

The computerized market coordinator accepts those offers that satisfy the market demand during the day at the *lowest total procurement cost*, simultaneously determining the market price as the highest accepted Price/unit for that quarter.

If your offer has not been accepted, it means that other offers were able to satisfy the market demand at a lower or equal cost. The results are displayed on the right side of the table; you may need to scroll to the right to see them. Once you have reviewed the results of the previous day enter your offers for the next day for each plant and submit.

The right side of the table is filled in after everyone has submitted their offers. Your profit during each quarter of a day is:

(Units Sold × market price + Start-Up Fees collected) – (Units Sold × Cost/unit + Start-Up Costs incurred)

<page 5 OCM>

Offers are sent to the computerized market coordinator when you click the Submit button or when the day is over. Your offer from the previous day will be automatically submitted for you if you choose not to make any changes during the course of a day.

The computerized market coordinator accepts those offers that satisfy the market demand during the day at the *lowest total offered cost*. After the offers are selected, the market price is determined as the highest accepted Price/unit for that quarter.

If your offer has not been accepted, it means that other offers were able to satisfy the market demand at a lower or equal cost. The results are displayed on the right side of the table; you may need to scroll to the right to see them. Once you have reviewed the results of the previous day enter your offers for the next day for each plant and submit.

The right side of the table is filled in after everyone has submitted their offers. Your profit during each quarter of a day is:

(Units Sold × market price + Start-Up Fees collected) – (Units Sold × Cost/unit + Start-Up Costs incurred)

<page 5 SOA>

Offers are sent to the computerized market coordinator when you click the Submit button or when the day is over. Your offer from the previous day will be automatically submitted for you if you choose not to make any changes during the course of a day.

The computerized market coordinator orders offered Prices/unit from lowest to highest for each quarter of the day. Market's bids to buy the product are ordered from highest to lowest. These two sorted lists will cross. The offered Price/unit where these lists cross becomes the market price during the quarter. The market coordinator accepts all offers with Prices/unit lower than the market price. If there is more than one offer exactly equal to the market price, then as many of those offers will be accepted as it is enough to satisfy the market demand during that quarter of the day.

If your offer has not been accepted, it means that other offers were able to satisfy the market demand at a lower or equal cost. The results are displayed on the right side of the table; you may need to scroll to the right to see them. Once you have reviewed the results of the previous day enter your offers for the next day for each plant and submit.

The right side of the table is filled in after everyone has submitted their offers. Your profit during each quarter of a day is:

(Units Sold × market price) – (Units Sold × Cost/unit + Start-Up Costs incurred)

<page 6>

A history of the prices from the past 10 days and the sold quantities during each quarter of the last day are displayed in the bottom portion of your screen.

Information about all plants (including yours) is available to all sellers by clicking on the Technology and costs button.

Plants are restarted at the beginning of each day, meaning that during the first quarter of each day you receive your start-up fee and incur the start-up cost if you sell the product.

At the end of today's session, your 'computer dollars' will be converted into cash at a rate of #exchangeRate# computer dollars to US$1. If you have any questions please raise your hand. Press Start when you are ready to begin.

Even if you decide to keep your offer from the previous day, click the Submit button. The experiment will advance to the next day after everyone has clicked on the Submit button.

Appendix C Sample Screen Shot

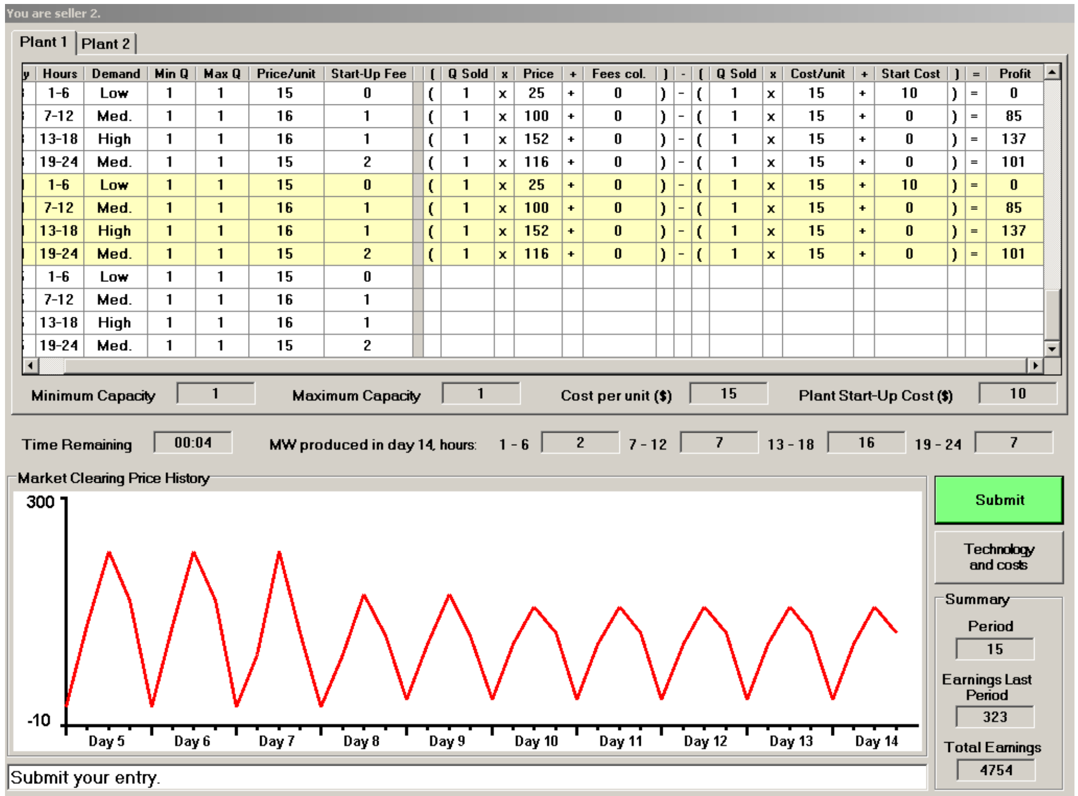

Fig. 7 Sample Screen Shot.