Mitigating Market Power in Deregulated Electricity Markets

*By Seth Blumsack and Lester B. Lave**

Abstract

Conventional measures of market structure used by economists, such as the Herfindahl Hirschman Index (HHI), give a misleading picture of the competitiveness of electric power markets, since these metrics do not consider the special properties of electricity as a commodity. The notion of a "pivotal supplier" is better-suited to the electric power industry; one or more players are pivotal if they have the ability to blackout an area by withholding generating capacity. Our analysis of pivotal oligopolies in California, PJM, and New York finds that all three of these markets are far less competitive than their HHIs would suggest. Even without explicit collusion, groups of suppliers are able to influence prices through strategic bidding behavior. We also evaluate five candidate market-power mitigation systems within the context of these three power systems. The cost of capacity expansion, either through new generation or transmission, will increase costs past the point of efficiency savings from restructuring. Additional transmission will also be ineffective without competitively-priced imports. Price caps and forced divestiture will likely decrease system operating efficiency. Long-term contracts will not mitigate market power unless the contract terms are sufficiently long and can be structured to efficiently distribute risk. We also find that different mitigation schemes have very different cost and effectiveness implications for different power systems; no one solution should be applied to every operating area.

Introduction

All competitive markets are free markets, but not all free markets are competitive. Markets where one or more firms have the ability to raise price and profit are unlikely to yield benefits for consumers when regulation ends. The experience of California and Pennsylvania, the two U.S. pioneers in electric restructuring, could not have been more different. Most observers saw California's energy crisis as a "perfect storm" in which drought, high demand, and fuel supply issues converged to raise prices. A deeply flawed market design exacerbated these effects. An uncompetitive market structure certainly received some blame for California's power woes, but the conventional wisdom maintained that minor modifications to the market rules, together with a respite from the perfect storm, would produce a competitive electricity market that would serve consumers far better than the regulated system.

This paper summarizes results from Blumsack, Lave, and Perekhodtsev (2002) and Blumsack and Lave (2004). California, PJM, and New York are shown to have market structures far less competitive than conventional metrics would suggest. Mitigating the market power of the largest suppliers in each system will raise costs, thus eroding what little savings have been gained thus far from deregulation. Further, each mitigation option has very different cost, effectiveness, and efficiency implications for a given system; different mitigation schemes will work best in different systems.

Structure of the California, PJM, and New York Electricity Markets

Most analyses of California's power crisis are performance-based – the salient question is the amount of market power actually exercised.[1] Borenstein, Bushnell, and Wolak (2000) and Joskow and Kahn (2002) find that electricity prices exceeded competitive levels for a large number of hours during the summer of 2000, even after accounting for fundamentals such as the Northwest drought and natural gas supply disruptions.

In contrast to the analyses of market performance, our emphasis is on measuring the structure of bulk power markets. The conventional tool used by economists to measure market structure is the Herfindahl-Hirschman Index (HHI); the sum of the squared market shares of every firm in the market. The HHI ranges from zero (a perfectly competitive market) to 10,000 (monopoly). The HHI has few underpinnings in economic theory, but remains the generally accepted measure of the potential for market power. After deregulation and divestiture by the state's investor-owned utilities, California's HHI was 664. The HHI in PJM is 1,160 and 637 in the New York ISO. U.S. antitrust regulations define a concentrated market as one with an HHI exceeding 1,800 (DoJ/FTC 1997), so proponents of electricity deregulation could argue persuasively that these markets would be competitive.

In markets for electricity, however, the HHI is a poor measure of market structure and has been shown to be a poor predictor of market performance (Williams and Rosen 1999); an HHI less than 1,800 does not indicate that deregulation will lead to a competitive market. Since electricity demand and supply must balance at each second, the largest supplier can disrupt this balance by withholding generation capacity from the market during peak periods, resulting in price spikes or blackouts. FERC refers to such a firm as a pivotal supplier.[2] Previous work (Blumsack, Lave, and Perekhodtsev 2002), has argued that FERC's pivotal supplier designation does not go far enough, since two or more suppliers acting together could be pivotal. Coordinated withholding by multiple generators would violate the Sherman Antitrust Act, but withholding without communication is not illegal. The potential for implicit collusion is shown in Perekhodtsev, Lave,

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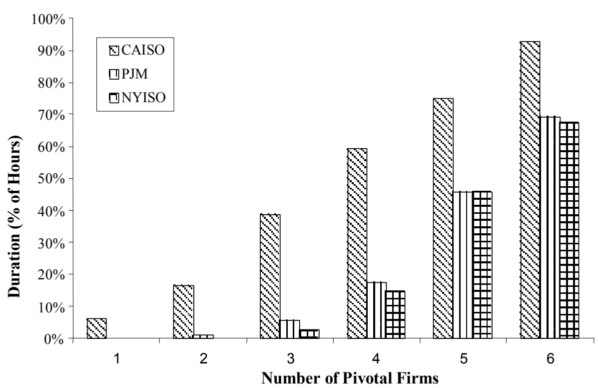
[1] See footnotes at end of text.

and Blumsack (2002), who model electricity auctions as Bertrand-Edgeworth competition with a capacity constraint. The Nash equilibrium is not a single-price bid for each firm, but rather a distribution in which the probability of bidding above marginal cost is greater than zero. They show that power prices in California decrease as the size of the pivotal group grows. Simulations by Talukdar (2002) provide further evidence that suppliers in hourly auctions can learn quickly to bid as oligopolists, even with no communication between bidders.

Since market power depends on both the demand and supply sides of the market, the load-duration curve can be used to indicate during which hours one, two, or more suppliers acting together would have market power. A group of *n* firms is said to form a pivotal oligopoly in a given hour if the surplus system capacity in that hour is less than the combined generation assets of the *n* firms. The surplus system capacity (as well as generation ownership) is based on demand and a residual measure of supply which excludes committed power and inflexible (must-run) generation resources such as nuclear and geothermal.[3]

Figure 1
Pivotal Firm Duration Curves for California, PJM and New York



The Pivotal Firm Duration Curve calculated for California over the period of high prices (a one-year period between June 2000 and June 2001) is shown in Figure 1. California's deregulation scheme was unique in that the state's utilities were not allowed to engage in long-term contracting, reducing the amount of data needed to calculate the number of pivotal firms in a given hour. Pivotal Firm Duration Curves are also calculated for PJM and the New York ISO over the same period. The curves for PJM and New York overstate market power since long-term contracts are not factored in to residual demand and supply.

The Pivotal Firm Duration Curves in Figure 1 imply that electric power markets in California, PJM and New York are far less competitive than conventional measures would suggest. For example, in California during the crisis period, an oligopoly consisting of three or fewer firms could have set the market price 40% of the time. PJM and New York appear more competitive than California, but far less competitive than their HHIs would suggest.

Mitigation Options

In most markets, holding inventories is sufficient to guard against the exercise of market power. In electricity markets, large-scale storage is too expensive; we examine some other options for mitigating market power.

FERC's Solution: SMD and SMA

In June 2001, FERC effectively halted electricity deregulation in the West by imposing cost-based price caps on the entire Western Interconnect. FERC's Standard Market Design Order demands that grid operators implement a "hard cap" at all times of the year, with additional cost-based bid caps during times of high prices.[4] Under cost-based bid caps, in which price is constrained to equal variable cost, the fixed costs of a new generating plant can be recovered only if its variable costs are lower than the market price. Determining the profitability of new plants would require knowledge of how often the market price would exceed the variable cost of the new plant. This in turn would require the generator to know the marginal cost curve of every plant in the system, and how the system-wide marginal cost curve would change with the addition of new capacity. FERC would need to know the same information in order to determine the "correct" cap on the market price. In other words, cost-based mitigation is a higher-cost version of regulation. FERC would replace the regulated system, with its high costs and certain profits, with a similar high-cost system with uncertain profits.

Another of FERC's proposals (the Supply Margin Assessment, or SMA) would apply price caps only to pivotal suppliers.[5] While SMA is certainly an improvement over widespread price caps, the screen currently proposed by FERC overestimates the ability of suppliers to be pivotal, since monthly or annual average loads would be used in place of the actual load duration curve.[6] The FERC proposal would treat a supplier as pivotal over an entire month or year, even if they were pivotal in only a few hours. Further, the SMA will only screen for pivotal monopolies; the Pivotal Supplier Duration Curves in Figure 1 suggest that regulators should also be concerned with pivotal oligopolies.

Capacity Expansion

Market power in electric power systems can be reduced by constructing excess generation or transmission capacity. The appeal of capacity expansion as a market-power mitigation strategy depends on how much is needed, since the investment will raise costs, as shown in Table 1.[7] For example, mitigating pivotal duopoly in California would require generation investments amounting to 3.5 GW, or between \$2.4 billion and \$4.8 billion. Electricity costs would rise by between 13 and 27 cents per kWh in order to mitigate pivotal duopoly.

Mitigating market power through capacity expansion is socially beneficial if the costs are offset by other benefits of deregulation, such as increased operating efficiency or new services which benefit consumers. California's failure to mitigate market power has cost the state dearly in terms of rolling blackouts and much higher prices. However, expanding generation capacity to prevent a pivotal duopoly would have cost between 13 and 27 cents per kilowatt hour and would not have completely mitigated a pivotal group of three firms or more. In Pennsylvania, prices have remained stable with deregulation (partially due to mandated rate freezes); PJM too would see costs rise if it were to mitigate market power through capacity expansion.

Figures from Hirst (2001) and Blumsack, Lave, and Perekhodtsev (2002) suggest that the cost of mitigating pivotal duopoly through transmission expansion would be about one cent per kWh; clearly a lower-cost solution than new generation. Further, siting generation in California has historically been difficult; expanding transmission capacity may be easier if additional lines can be added to existing towers. In general, however, the effectiveness of building transmission is limited by the extent of competitively-priced imports. If neighboring systems experience coincident peaks, import power will not be available at competitive prices, and investment in transmission would largely be wasted. Table 2 shows how monthly loads are correlated between selected Western states and Eastern NERC Regions. The negative correlations between California and the Northwest suggest noncoincident peaks; California could easily draw on surplus Northwest hydropower to combat the exercise of market power. Monthly loads in the East, however, are highly correlated; building transmission to solve the system-wide pivotal supplier problem would run into competition for neighboring imports during peaking periods (as well as native-load constraints on availability), and large line losses from more distant resources.

Increased Demand Response

Making demand responsive to price is a worthy goal, but by itself is unlikely to eliminate pivotal suppliers, since a monopolist can still exercise market power when the demand curve is downward-sloping. Sweeney (2002) asserts that small amounts of demand response could curb the exercise of market power. Table 3 shows the amount of demand response needed to mitigate all pivotal oligopolies of a given size in California and PJM between June 2000 and 2001. Smaller amounts of demand response will mitigate pivotal suppliers at some times but not others. The price elasticity of demand would have to range between -0.1 and -1.55 to mitigate pivotal suppliers in California (Blumsack and Lave 2004); the best estimates of short-run elasticity are around -0.3 (Houthakker 1951, Caves and Christensen 1980). If suppliers are pivotal in a small number of hours, demand response may be preferable to capacity expansion.

Table 2
Demand Correlation Matrices for Western States and the Eastern Interconnect

Western States

	AZ	CA	NM	OR	WA
AZ	1				
CA	0.90	1			
NM	0.93	0.80	1		
OR	-0.10	-0.04	0.10	1	
WA	-0.48	-0.41	-0.33	0.77	1

Eastern Interconnect

PJM	1				
NYISO	0.92	1			
ECAR	0.90	0.78	1		
SERC	0.87	0.83	0.88	1	
NEPOOL	0.91	0.86	0.84	0.74	1

Divestiture

Prior to the opening of California's deregulated electricity market, the state's investor-owned utilities were required to divest many of their generation assets. Regulators believed that without divestiture, incumbent utilities would have tried to influence the state's electricity auction. Given that regulators acknowledged the likely pivotal status of the utilities, their willingness to let individual suppliers control substantial shares of capacity is surprising. We infer that regulators focused on market share data and concluded that the resulting market would be competitive, as the HHI indicated. From the breakup of Standard Oil to the threatened breakup of Microsoft, divestiture has long been a favorite tool of an-

Table 1
The Cost of Mitigating Market Power Through New Generation

Pivotal Group Size		California		PJM		NYISO	
	System Capacity (GW)	54		60		38	
	Capital Cost ($/kW	$600	$1200	$600	$1200	$600	$1200
1	Additional Capacity Needed (GW)	10.5		0.0		0.0	
	Required Investment ($billion)	7.12	14.24	0.00	0.00	0.00	0.00
	Marginal Cost (cts/kWh)	35.25	70.51	0.00	0.00	0.00	0.00
2	Additional Capacity Needed (GW)	3.5		5.4		0.0	
	Required Investment ($billion)	2.40	4.81	3.67	7.34	0.00	0.00
	Marginal Cost (cts/kWh)	13.44	26.88	196.27	392.54	0.00	0.00
3	Additional Capacity Needed (GW	3.3		5.4		4.0	
	Required Investment ($billion)	2.24	4.49	3.66	7.32	2.73	5.46
	Marginal Cost (cts/kWh)	5.68	11.37	38.73	77.46	83.66	167.31
4	Additional Capacity Needed (GW	3.2		4.0		2.9	
	Required Investment ($billion)	2.15	4.31	2.74	5.48	1.95	3.90
	Marginal Cost (cts/kWh)	3.73	7.46	12.55	25.11	15.11	30.22
5	Additional Capacity Needed (GW	3.0		3.6		2.5	
	Requited Investment ($billion)	2.01	4.02	2.46	4.92	1.70	3.4
	Marginal Cost (cts/kWh)	2.95	5.90	4.82	9.64	4.81	9.63
6	Additional Capacity Needed (GW	2.9		3.6		2.3	
	Required Investment ($billion)	1.96	3.92	2.46	4.91	1.57	3.14
	Marginal Cost (cts/kWh)	2.39	4.78	3.20	6.40	3.28	6.57

titrust regulators. In the context of electricity markets, divestiture seems appealing; if firms are permitted to hold only small amounts of capacity, they may cease to become pivotal.

The appeal of divestiture increases as excess system supply decreases. Table 4 recalculates the Pivotal Firm Duration Curves for California and PJM under various divestiture scenarios, assuming that inflexible generation (nuclear and geothermal) is not divested. As the maximum generator size shrinks to 1 GW, the hours when firms were pivotal falls below 10% in PJM. The frequency of a six-member pivotal oligopoly falls from 93% of hours between June 2000 and June 2001 to 8% of hours. Divestiture is effective in limiting the incidence of pivotal firms in California, but since surplus capacity is higher in PJM, proportionally more divestiture would be required in California.

Table 3
Mititating Pivotal Suppliers Through Demand Response

Pivotal	CA Demand Response		PJM Demand Response	
Group Size	MW	%	MW	%
1	4840	12%	5395	15%
2	3534	10%	5395	15%
3	3296	10%	5381	18%
4	3165	12%	4030	16%
5	2951	12%	3617	16%
6	2877	13%	3611	19%

The effectiveness of divestiture as a market power mitigation strategy is limited by economies of scale in generation. Systems dominated by large plants are less amenable to market-power mitigation through divestiture. For example, the largest plant in Arkansas represents 20% of the state's capacity. Ownership of large plants can be broken up into smaller shares, but control must still remain in the hands of a single party. The incentives of a private ownership group and the ISO are likely to be incompatible, with owners desiring to maximize joint profits and the ISO seeking to maximize system reliability at low cost.

Table 4
Pivotal Firm Duration Curves in California and PJM Under Divestiture Scenarios

Divestiture in California

	PFDC Under Capacity Ownership Limit (%Hrs)				
Number of Pivotal Firms	No Limit	4GW	3GW	2GW	1GW
1	6%	5%	4%	3%	3%
2	16%	13%	8%	5%	3%
3	39%	32%	20%	8%	4%
4	59%	55%	41%	14%	5%
5	75%	70%	60%	26%	6%
6	93%	88%	75%	41%	8%

Divestiture in PJM

	PFDC Under Capacity Ownership Limit (%Hrs)				
Number of Pivotal Firms	No Limit	4GW	3GW	2GW	1GW
1	0%	0%	0%	0%	0%
2	1%	1%	0%	0%	0%
3	6%	6%	2%	0%	0%
4	18%	17%	6%	1%	0%
5	46%	45%	16%	4%	1%
6	69%	69%	42%	10%	2%

For California or PJM, total demand is many times larger than the efficient generation size, so technical economies of scale are not an issue (Christensen and Greene 1976, Johnson 1960). However, there may be important economies of scale in management. A single large combined cycle natural gas generator might use only a fraction of the time of a pollution control specialist, personnel manager, and gas purchaser.[8] While these services could be supplied by consultants, the costs might be higher or the quality of service lower.

Recent consolidation in the nuclear industry suggests that managerial economies may be important. In addition to operating at lower costs, skilled or better-trained operators appear to deliver higher availability times and higher capacity factors for their plants.[9] Table 5 shows the progress of capacity factors for nuclear power plants between 1993 and 2002. While the firm-wide capacity factor has increased since 1993 for all firm sizes, larger firms have seen greater gains. The average nuclear capacity factor for firms with only one nuclear plant grew by 15% between 1993 and 2002; during the same period the average nuclear capacity factor for the industry's largest firm grew by 27%.

Long-Term Contracts

California's deregulation scheme has been widely criticized for prohibiting long-term contracts. Sweeney (2002) suggests that encouraging forward contracts in the three-to-five year range would greatly reduce the ability of generators to exercise market power. Such contracts were signed *en masse* at the end of California's power crisis; the contract prices were lower than the prevailing spot prices at the time the contracts were signed, but far above the prices prevailing in the regulatory era or the post-crisis period.

Frequent auctions encourage implicit collusion (Talukdar 2002, Perekhodtsev, Lave, and Blumsack 2002). Reducing the frequency of trading through long-term contracts would discourage this sort of collusion. Contracts in and of themselves will not cure the pivotal supplier problem; the structure of the contracts must reduce the incentive of suppliers to charge high prices. The only way to achieve this is for the buyer of the contract to have some outside option as a bargaining chip (Laffont and Martimort 2002) in case the contract price offered by the supplier is too high. The bargaining power of a buyer such as an ISO comes from the ability to build new generation; such an outside option of building new capacity implies that the contracts market must support contracts longer than the three- to five-year deals signed by California, possibly as long as life-of-plant contract. A generator seeking capital for a new plant is unlikely to attract lenders without a guarantee that they will be repaid. Similarly, public utility commissions are unlikely to allow utilities to include the cost of new plants in the rate base unless the utility is actually earning money from the plant. Capacity built for the sole purpose of deterring market power (while the utility actually serves load through the spot or shorter-term contract markets) will erode efficiency gains from deregulation, as discussed in the section on Capacity Expansion.

Long-term contracting will successfully deter market

Table 5
Consolidation and Performance in the Nuclear Power Industry, 1993 - 2003

1993

# of Plants	Number Of Firms	Mean Capacity Factor	Median Capacity Factor	Standard Deviation
1	35	0.669	0.713	0.166
2	9	0.644	0.710	0.212
3	2	0.660	0.660	0.096
More than 3	1	0.635	0.635	0.000

1997

No of Firms	Number of Plants	Mean Capacity Factor	Median Capicty Factor	Standard Deviation
1	35	0.673	0.748	0.240
2	8	0.733	0.829	0.181
3	3	0.758	0.768	0.065
More than 3	1	0.540	0.540	0.000

2000

# of Plants	Number Of Firms	Mean Capacity Factor	Median Capacity Factor	Standard Deviation
1	33	0.742	0.824	0.221
2	9	0.802	0.841	0.131
3	3	0.814	0.861	0.096
More than 3	1	0.883	0.883	0.000

2002

No of Firms	Number of Plants	Mean Capacity Factor	Median Capicty Factor	Standard Deviation
1	29	0.823	0.863	0.166
2	8	0.842	0.852	0.085
3	3	0.875	0.884	0.017
More than 3	1	0.911	0.911	0.000

power only if the contract is structured such that the incentives of the buyer and seller coincide. Imperfect information and uncertainty lead to moral hazard, since the buyer cannot observe how the generator is running the contracted plant. If the contract specifies a fixed price per MWh, with a take-or-pay clause and a fuel pass-through, the generator has little incentive to bargain for the lowest fuel price. Further, moral hazard issues arise in the staffing and operations of the plant specified in the contract (and its construction costs, if the plant is new). The buyer wants the generator to exert a high level of effort in keeping costs down and reliability high. Meanwhile, the generator wants to do as little as possible while satisfying the terms of the contract.[10]

The multi-task nature of electricity contracts can also give rise to diseconomies of scope. Each task required of the generator (purchasing fuel, maintaining the plant, and so on) imposes an additional moral hazard problem (Laffont and Martimort 2002). The marginal cost of resolving an additional incentive incompatibility may be larger than the marginal expected benefit from having the generator perform an additional task.[11] The generator's decreasing marginal utility of consumption implies that additional effort must be compensated with a more-than-proportional increase in the contract price. If such diseconomies exist, it may be a lower-cost solution for the buyer to assume some of the responsibilities normally given to the generator.[12]

Conclusion

Restructured electricity markets in California, PJM, and New York may be free, but they are far less competitive than conventional market-power metrics would suggest. The fact that supply and demand must balance at all times gives monopoly power when demand is sufficiently high to allow pivotal oligopolies to threaten blackouts by withholding supply. Pivotal firms as large as six groups could have set the price in a majority of the hours of the year in all three systems. Large pivotal oligopolies can be easily formed without explicit communication.

California taught the U.S. that transforming regulated electricity markets into competitive markets is far more difficult than was assumed. FERC's counterparts in Europe and Asia would do well to heed this same lesson. Regulators need to more carefully assess whether a combination of actions exist that would control market power while still offering savings to consumers. FERC's attempt to control this power by controlling price would prevent new capacity, since fixed costs would not be reimbursed. FERC's solution would target only single pivotal suppliers, but we show that larger pivotal groups also had potential to exercise market power. Expanding generation capacity is promising but prohibitively expensive. Expanding transmission capacity is attractive only if capacity is available for export, which may be true in the West, but not in much of the Eastern Interconnect. Forcing suppliers to divest assets would reduce their market power, but would also raise costs due to economies of scale in management. Making demand more responsive to price holds promise for preventing the extreme high prices that prevailed in California. With sufficiently long time horizons, long-term contracts could prevent market power if the difficulties of moral hazard and risk distribution could be surmounted.

Footnotes

[1] The conventional measure of market performance in economics is the Lerner Index, defined as the percentage by which price exceeds marginal cost (also known as the price-cost markup). Using the Lerner Index to assess the performance of electricity markets has been widely criticized; see Borenstein, Bushnell, and Kittel (1998).

[2] See, for example, FERC Supplier Margin Assessment Order, 97 FERC ¶ 61,219 at 61,967.

[3] The calculation of the Pivotal Firm Demand Curve is discussed in more detail in Blumsack, Lave, and Perekhodtsev (2002). They calculate two sets of Pivotal Firm Duration Curves, with and without must-run energy. The sets of curves are similar for California and New York, but the inclusion of must-run energy (mostly nuclear power) in the duration curve for PJM results in two- or three-firm pivotal oligopolies during every hour of the year.

[4] FERC Notice of Proposed Rulemaking, Docket No. RM01-12-000, ¶317,318,398 – 410.

[5] FERC Supplier Margin Assessment Order, 97 FERC ¶ 61,219 at 61,967. Whether this Order would supplant market-power mitigation discussed in the Standard Market Design has not yet been resolved.

[6] FERC Supplier Margin Assessment Order, Staff Paper on Supply Margin Assessment and Alternatives, Docket PL-02-8-000.

[7] The figures in Table 1 assume capital costs of between $600/kW and $1,200/kW, with anly used to prevent the exercise of market power; its costs are therefore only charged to those hours with a pivotal group of a given size. A detailed example of the cost calculations can be found in Blumsack and Lave (2004).

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