November 15, 2002

Office of the Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

RE: Docket No. RM01-12-000

Attached, please find a comment on the Commission's proposed Standard Market Design. The comment was written by Seth Blumsack, Dmitri Perekhodtsev, and Lester B. Lave of the Carnegie Mellon Electricity Industry Center (CEIC) at Carnegie Mellon University, Pittsburgh, PA.

CEIC (www.cmu.edu/electricity) is one of several Sloan Industry Centers. Established in 2001 with grants from both the Sloan Foundation and EPRI, the mission of CEIC is to work with companies, labor, regulators, the financial community, consumers, and technologists to make the electricity industry more competitive and its systems more reliable and secure, to create wealth, and to serve the public interest better by enhancing human resources, speeding organizational learning, improving its regulatory environment, and expediting new approaches to the generation, transmission, distribution, marketing, and use of electricity. CEIC's goals are to foster change in the industry, its regulation, and the way that industry stakeholders think about it by opening new business opportunities and bringing new insights to public policy. To accomplish this ambitious goal, the Center has embarked on a large program of interdisciplinary education and research, bringing together scholars from engineering, economics, public policy, and other areas.

The enclosed comment reflects the views of its authors, and is not necessarily intended to reflect the views of CEIC or its grantors. We hope the Commission will find our insights useful as it seeks to reform energy markets in the United States.

Seth Blumsack

Carnegie Mellon Electricity Industry Center

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Remedying Undue Discrimination	)	
Through Open Access Transmission Service	)	Docket No. RM01-12-000
And Standard Electricity Market Design	)	

INITIAL COMMENTS OF
SETH BLUMSACK, LESTER B. LAVE, AND DMITRI PEREKHODTSEV
ON THE STANDARD MARKET DESIGN NOPR
November 15, 2002

I. Introduction and Executive Summary

This comment seeks to address two issues in the Commission's Standard Market Design Notice of Proposed Rulemaking (NOPR), specifically in the areas of market power mitigation and analysis of market structure in regional electricity markets.

The Commission has recommended that the market monitoring committee of each Independent Transmission Provider (ITP) conduct a competitiveness analysis of their ITP's operating area. We agree with the need for such analysis, but disagree that the competitiveness of an ITP operating area can be accurately measured using a market-share metric. Measures of market structure based on market share were designed for use in industries where inventories are cheaply maintained and demand is elastic. Electricity is unique as a commodity in that is satisfies neither of these properties. We propose instead the use of a market structure metric based on the difference between the excess capacity of an ITP system and the generating capacity of firms within the system (in the spirit of the so-called *pivotal supplier* concept).[1]

[1] Much of this comment is based on Seth Blumsack, Dmitri Perekhodtsev, and Lester Lave, "Market Power in Deregulated Wholesale Electricity Markets: Issues in Measurement and the Cost of Mitigation," *Electricity Journal*, November 2002 (hereafter referred to as BPL), and Dmitri Perekhodtsev, Lester B.

When this methodology of assessing market structure is applied to several existing power pools or ISOs, they appear to be far less competitive than conventional, market-share measures would indicate, implying that mitigation measures would need to be put in place more often than conventional wisdom might suggest.

The mitigation measures proposed by the Commission in the NOPR consist primarily of bid caps, mandatory offer requirements, an increased role for demand response, and resource adequacy requirements. The first two mitigation measures are inherently problematic, in that the combination of mandatory sell requirements combined with price caps may amount to a "taking," in which the federal government obliges a firm to sell a good at a fixed price, a price which may not represent fair compensation to the firm. Such a mandatory offer requirement can only be made compatible with the takings clause of the U.S. Constitution if compensation is made on an average cost basis, a decision that brings the Commission squarely back to the regulated era it is trying to escape.

Even demand response, which we agree is vital (and we applaud the Commission for emphasizing in the NOPR), cannot be relied upon to mitigate the effects of market power. In many ITP systems, the amount of excess capacity would be sufficiently small relative to the generation capacity of a few large firms that increased responsiveness by consumers could solve only part of the problem, at best.

The resource adequacy requirement also may not go far enough in some ITP systems. In order to fully insure against the exercise of market power, the ITP would need to invest in enough generation to strip pivotal generators of their ability to be pivotal. Our calculations suggest that this is a very costly strategy, and may erode many of the (still uncertain) benefits that deregulation would hope to provide.

Lave, and Seth Blumsack, "An Application of the Theory of Pivotal Oligopoly to Electricity Markets," Working Paper, Carnegie Mellon Electricity Industry Center, Carnegie Mellon University (hereafter PLB), available at http://wpweb2k.gsia.cmu.edu/ceic/showResearch.asp?id=16.

INITIAL COMMENTS OF SETH BLUMSACK, LESTER B. LAVE, and DMITRI PEREKHODTSEV[2] ON THE STANDARD MARKET DESIGN NOPR

II. The Market Structure Metric Proposed In The Commission's NOPR Is Flawed

While the Commission correctly recognizes the need to measure the competitiveness of any given regional electricity market, the methodology proposed (NOPR ¶439) is likely to misrepresent the structure of the region's market. Metrics based on market share (such as the Herfindahl-Hirschman Index, or HHI) have few theoretical economic underpinnings, aside from the notion that highly concentrated markets are unlikely to yield competitive outcomes. Despite the lack of grounding in economic theory, market structure measurements like the HHI are generally regarded as acceptable for industries in which inventories exist (or are at least possible), demand is elastic, and barriers to entry cannot be erected by individual firms.

Unfortunately, none of these three features characterize the electric power industry, the Commission's attention to demand response in this NOPR notwithstanding. Therefore, measuring a market's competitiveness using market shares is inappropriate for regional bulk power markets.[3]

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[2] Seth Blumsack and Dmitri Perekhodtsev are PhD candidates in the Graduate School of Industrial Administration at Carnegie Mellon University, Pittsburgh, PA, and researchers in the Carnegie Mellon Electricity Industry Center (www.cmu.edu/electricity). Lester B. Lave is a University Professor and the Harry B. and James H. Higgins Professor of Economics and Finance in the Graduate School of Industrial Administration at Carnegie Mellon University, and co-director of the Carnegie Mellon Electricity Industry Center. The research underlying this comment was supported by a grant from the Sloan Foundation and EPRI. The opinions expressed in this comment belong to the authors, and are not necessarily those of the grantors, or of the Carnegie Mellon Electricity Industry Center or Carnegie Mellon University.

[3] See BLP, as well as Severin Borenstein, James Bushnell, and Christopher Kittel, "Market Power in Electricity Markets: Beyond Concentration Measures," University of California Energy Institute POWER Working Paper PWP-059, 1998.

Market structure analyses in the electric power industry must be based on the relationship between a system's supply/demand balance (or equivalently, its excess capacity) and the generating capacity of the firms operating within the system. Due to the unique nature of electricity, any such metric must have a *time* component in addition to the conventional *supply/demand balance* component. Consider the following simple example. Suppose that total generation capacity in a market is 100 units, and that firm *M* controls 18 units. Further assume that the ISO announces that demand in a certain hour is 90. Generating capacities of all plants, demand, and (often times) outages are known by all market participants. In this situation *M* knows that if it bids high prices for its units, the bid price on the 10th unit will be the market-clearing price (unless another generator bids an even higher price for its units). If the ISO does not buy at least 10 units from *M*, blackouts will occur. Cutting off power to all customers is unthinkable; blacking out an area of the city or instituting rolling blackouts is extremely painful. Thus, *M* knows that it has monopoly power.

Furthermore, *M* knows that the demand curve is vertical. The price that *M* bids for its 10th unit is limited only by its conscience, up to the point where the ISO is willing to institute rolling blackouts rather than pay that price. If every other firm in the market had less than 1% of market share, the HHI for this market would be 324, indicating an extremely competitive market. Instead firm *M* has monopoly power during these peak demand periods, with an implied HHI of 10,000.

The California ISO has recognized this situation and refers to the firm with monopoly power as a *pivotal firm*. The Commission has also responded to this problem through its Supplier Margin Assessment test for market-based ratemaking authority.[4] Throughout these comments, we will use the term "pivotal firm" to refer to a generator whose capacity exceeds the excess capacity of the system during a given time frame.

[4] See FERC Order in Docket Nos ER96-2495-015 et al., 97 FERC 61,219 [2001].

However, just as important as it is for the Commission to recognize the superiority of measuring market structure using a pivotal firm analysis, it is equally important to recognize that the potential exists for multiple firms, colluding either explicitly or implicitly, to act as a *pivotal oligopoly*. Consider again the fictional electricity market mentioned above. Total capacity is once again 100 units, and demand is again 90 units. Suppose that the largest two firms each had 8 units of capacity. Neither firm has monopoly power, although the two could act together to assert monopoly power. If no other firm had as much as 1% of capacity, the HHI would be only 212, but this is equivalent to a duopoly with an implied HHI of 5,000.

Note that such pivotal oligopolies can easily arise even in the absence of explicit collusion. PLB describes the evolution of pivotal firms and oligopolies in uniform-price auctions with no communication between bidders (and hence no opportunity for explicit collusion). Our model, which accounts for many of the salient features of auctions for electric power, predicts that bidders (even when the number of bidders is high) will occasionally stick their toes in the water, and bid uncompetitively (above marginal cost). As a result, in some instances enough capacity may be bid above the marginal cost to drive the market-clearing price above marginal cost. The resulting market-clearing price is shown to be dependent on both the market concentration in conventional terms and on the number of firms in the pivotal oligopoly. It is also shown that the number of firms in a pivotal oligopoly has much stronger effect on the expected market-clearing price.

Analyzing market structure based on the ability of pivotal firms or pivotal oligopolies to set the market price or cause blackouts can yield very different results from analyses based on the HHI. Measuring market structure conventionally would yield an HHI of 664 for California and would suggest a highly competitive market structure. Conversely, Figure 1 shows our pivotal oligopoly analysis for California for the period June 2000 to June 2001.[5] For every hour of the year, we calculated the minimum number of firms that, acting together, could set the market price. The

[5] Figures 1 through 4 are attached as an Appendix to this comment.

market shown in Figure 1 cannot be regarded as competitive. A pivotal monopoly existed during nearly 10% of the hours considered. For almost 50% of the time during the period considered, three or fewer firms acting in concert could have set the market price. A pivotal oligopoly of six or fewer firms existed nearly every hour of the year.

Figures 2 and 3 present the same analysis for PJM and the New York ISO. For reference, we calculate the conventional HHI for PJM to be 1,160 and the conventional HHI for New York to be 637. As can be seen from the figures, PJM appears more competitive than California, although far less competitive than the conventional HHI would suggest. New York appears more competitive than either California or PJM, though transmission and generation constraints in Long Island and Manhattan may give generators localized market power in those areas. The Commission has recognized this with its suggestions that such local load pockets be documented in analyses of regional market structures (NOPR ¶439).

Figure 4 illustrates that the pricing behavior during California's crisis is consistent with the predictions of pivotal oligopoly theory. The vertical axis in the figure represents the hourly price-cost margins normalized by the difference between the price cap and the estimated marginal cost in a given hour. This normalized price-cost margin is lies between zero and one (it equals zero if the price in a given hour is equal to the estimated marginal cost in that hour, and equal to one if the market-clearing price is equal to the price cap). The figure suggests that the prices will significantly exceed marginal costs when the pivotal oligopoly is made up of between one and six firms, as was often the case when we examined California, PJM, and New York.

Several analyses have suggested that long-term contracts provide an effective way to guard against market power.[6] Since spot markets, particularly for electricity, are fundamentally volatile, such a move would likely have the impact of reducing the volatility of prices faced by customers. However, given the current incentive

[6] See, for example, James Sweeney, *The California Power Crisis*, Hoover Institution Press, 2002.

structure in electricity markets, we question whether the broad use of long-term contracts would result in customers seeing competitive prices. Why would a pivotal firm offer to sell a long-term contract at average cost when it can get a higher price in the spot market? California's experience signing long-term contracts following the power crisis illustrates what we perceive as problems with the market's incentive structure. We do not know exactly what prices were paid by the California Department of Water Resources for long-term power, but given the renegotiation efforts certainly underway, these prices were certainly far above the average cost of operating a generating unit.

III. **The Commission's Bid Cap Requirement Will Re-Introduce Regulatory Inefficiencies That Deregulation Was Designed To Eliminate**

In its market mitigation plan, the Commission recommends the use of bid caps, combined with obligations to offer power in the face of high demand periods or uncompetitive market scenarios (NOPR ¶¶418 – 427). The Commission is correct to suggest that bid caps based purely on operating costs provide insufficient opportunity for capital recovery by investors in new generation, reducing incentives to expand capacity. However, the Commission's use of a flat adder (NOPR ¶¶420 – 421) as a form of compensation for risk or as a mechanism for capital recovery is inappropriate. Such flat adders, which do not account for uncertainty, changing capital markets, or other regulatory risk, may result in an unfairly low level of compensation for generation owners. The government cannot constitutionally order firms to provide goods or services at unfair prices, and the combination of mandatory offer requirements and flat bid cap requirements may result in such a "taking."

The only bid cap requirements that would be compatible with the takings clause of the U.S. Constitution would have to be based on a generating unit's average cost of generation, not its marginal cost. However, such bid cap requirements would simply result in the Commission having to face all of the regulatory complications that were left to State PUCs during the regulated era. A major challenge under regulation was determining the capital costs of a generating unit, as well as its operations and maintenance costs. A major attraction of deregulation was being able to move away from a system in which generators first had to receive permission to build new capacity, and then prove their costs to regulators so that the proper price could be fixed.

Furthermore, paying the total cost of each unit removes the incentive to build low-cost generation, since owners of new units would automatically be compensated. Furthermore, the Commission would have to review each proposed generation addition, and then authorize its construction, since otherwise an investor could build vast excess capacity knowing that he would be fully compensated. In other words, setting price caps is a potential trap that leads back to the regulation that the Commission and states have been trying to eliminate.

IV. The Market Structure Of Many Regional Electric Systems Is Not Amenable To Competition

Analysis of the California market using the conventional HHI suggests a highly competitive market structure, and provides evidence to validate the "perfect storm" hypothesis of the California power crisis. The perfect storm hypothesis states that California's electricity woes (blackouts and high prices) were caused by an unfortunate confluence of fundamentals. A severe drought in the Pacific Northwest arrived just at the same time as California's capacity margins were being pushed to their limits by load growth, both in Silicon Valley as well as in other Western areas, as well as transmission constraints which limited the amount of power that could be shipped to load centers. Poor market design simply exacerbated the effects of this unfortunate confluence of events (which was unlikely to occur again in the near future), implying that minor changes to the California ISO's markets could guard against high prices in the future, and that deregulation in California could still provide consumers with net benefits.

Conversely, the pivotal firm analysis discussed in these comments suggests exactly the opposite. California's power crisis was first and foremost caused by a highly uncompetitive market structure, in which a small number of firms were given a large number of opportunities to set arbitrarily high market prices. The problems associated with an inherently uncompetitive market were simply magnified by the coincident drought and load growth. Simply tinkering with the design of the spot market (as the Commission's NOPR proposes to do) will not fix the market's structural flaws. The only way to create a competitive market for electricity is to greatly reduce the number of hours in which the market sports a pivotal oligopoly consisting of a small number of firms.

However, it is not clear that the approach taken by the Commission will be sufficient to yield a competitive market structure. The Commission has placed great emphasis on improving demand response in the face of restructuring. We agree that this is vital and has not been given sufficient attention in restructuring efforts to date. However, particularly in the face of a pivotal oligopoly whose capacity greatly exceeds spare capacity in the system, demand response can only go as far as to reduce the ability of the oligopoly to set prices; it cannot fully eliminate this ability. Similarly, we applaud the Commission's recognition of local load pockets as a potential source of market power. This recognition, however, simply underscores the point that structural problems cannot be mitigated away, as the Commission would hope (see NOPR, ¶439, note 216).

The Commission's resource adequacy requirements (NOPR ¶¶457 – 550) represent one possible solution to the structural problems faced by would-be competitive regional electricity markets. Simply building more generation (probably owned by the ITP) could reduce the ability of pivotal oligopolies to set market prices by expanding the system's excess capacity. However, the investments required would in many cases be far larger than the figures suggested in the Commission's resource adequacy plan. For example, in California, the two largest generators control 12.5% and 10.5% of capacity, respectively. Therefore, the state would need to expand generating capacity by at least 25% to protect itself against a pivotal duopoly being able to set the market price. BLP calculates that this could add around one cent per kWh to electricity costs in the state. Whether the benefits from deregulation would outweigh those costs remains to be seen, but the evidence thus far has not been encouraging.

V. Appendix– Supporting Graphics

Figure 1: Pivotal Firm Duration Curve for California (June 2000 – June 2001)

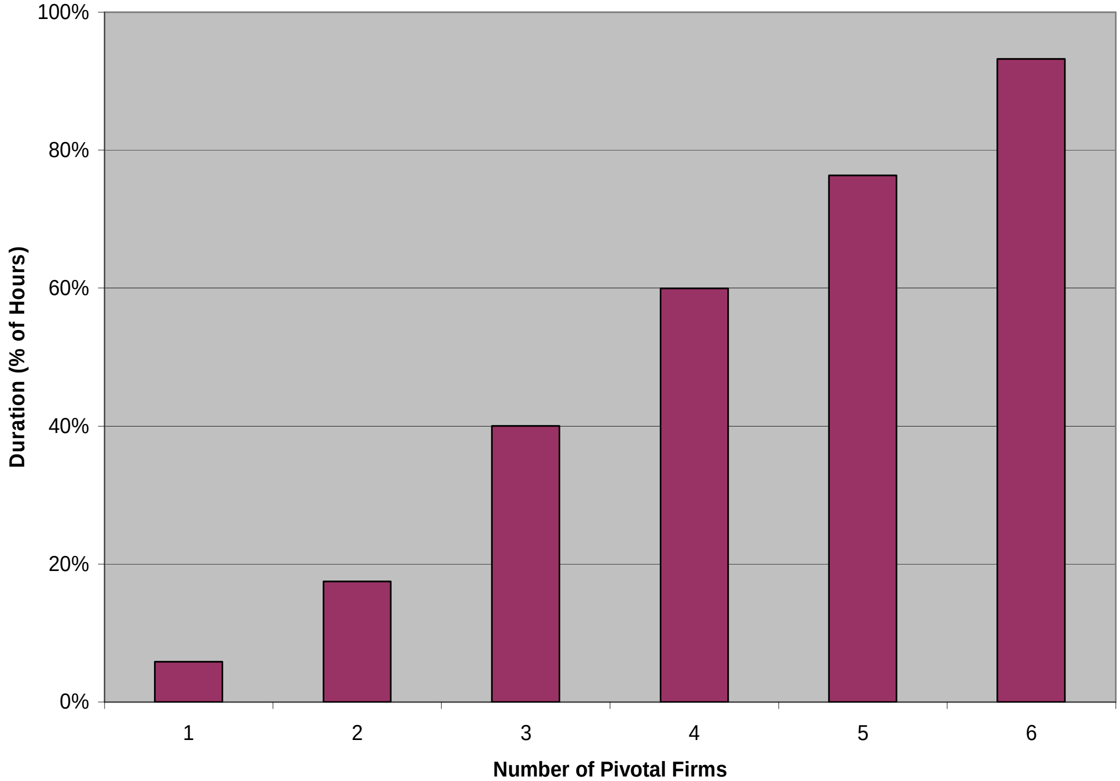

Figure 2: Pivotal Firm Duration Curve for PJM (June 2000 – June 2001)

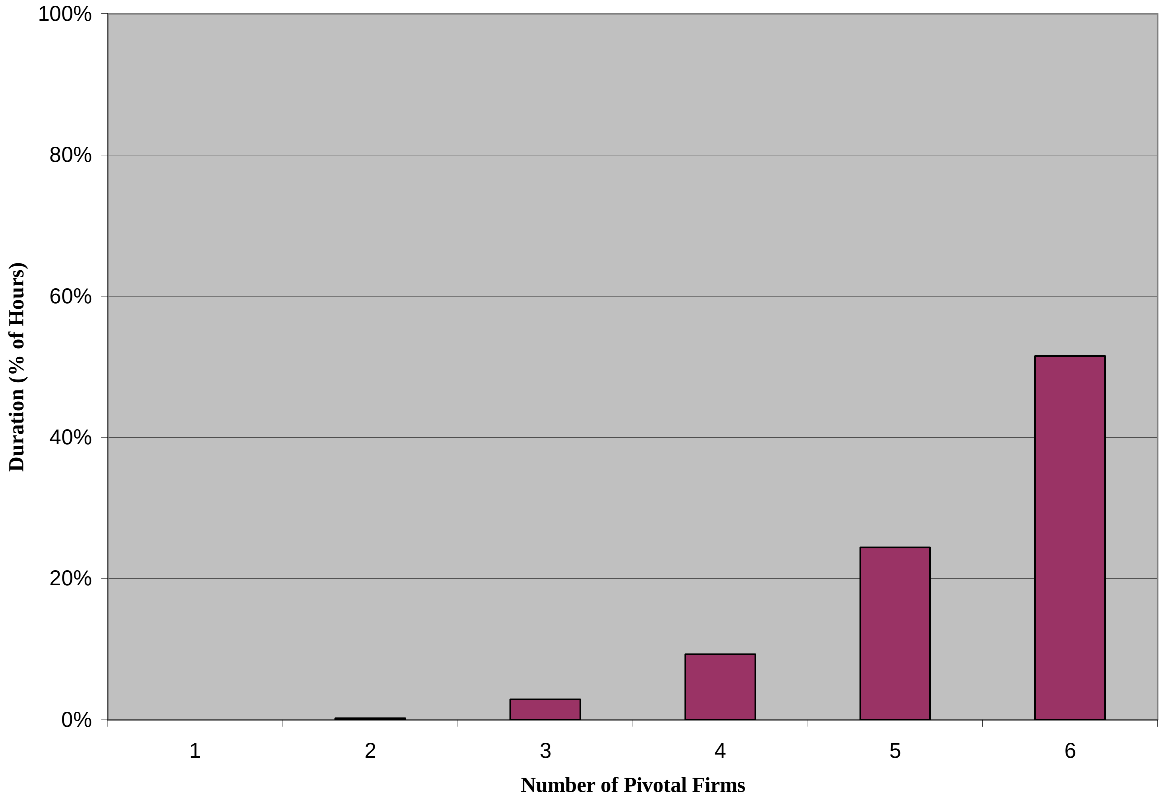

Figure 3: Pivotal Firm Duration Curve for New York (June 2000 – June 2001)

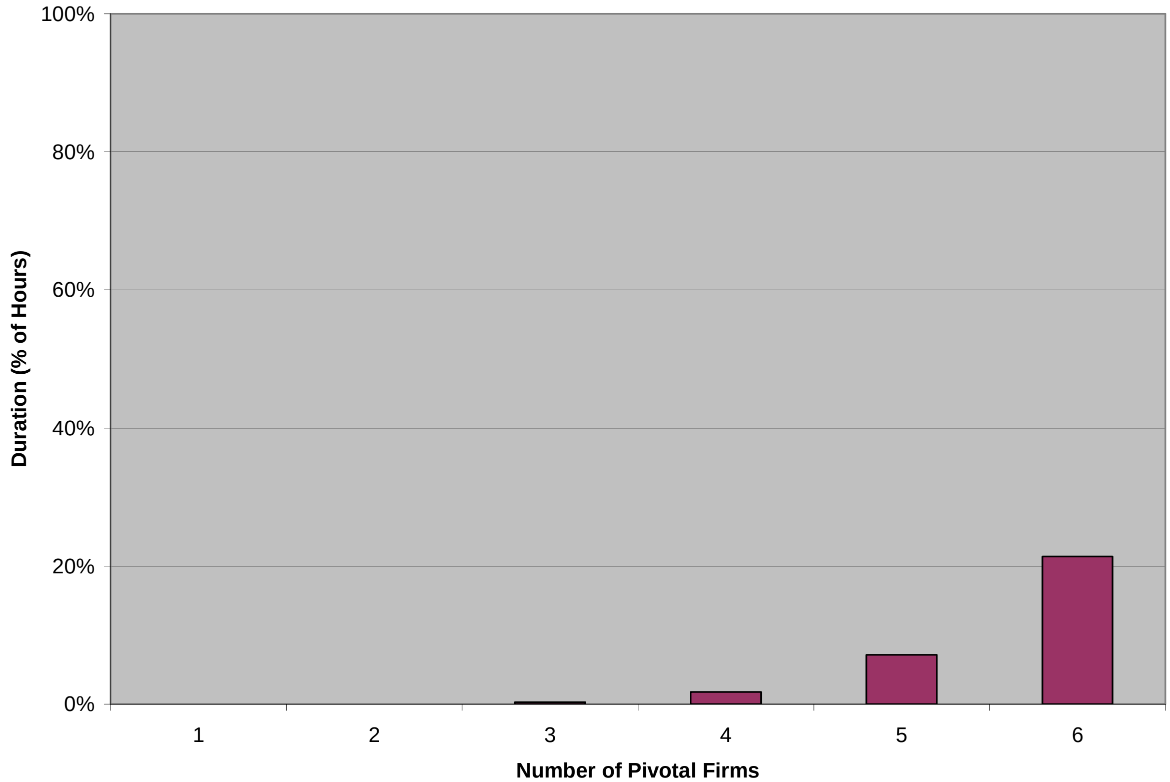

Figure 4. Normalized Prices in California and the Number of Pivotal Firms