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MARKET POWER ANALYSIS OF THE ELECTRICITY GENERATION SECTOR

William H. Hieronymus
J. Stephen Henderson
*Carolyn A. Berry**

The issue of market power in the electricity industry is becoming increasingly important as traditional cost-of-service regulation is being replaced by markets and competition. At the federal level, the Federal Energy Regulatory Commission (FERC or Commission) is continuing the transition to market-based approaches in wholesale power markets that it began about ten years ago. At the retail level, several states now allow retail customers to choose their own electricity supplier, although under terms and conditions that will provide considerable protection against risks that otherwise would occur in a totally deregulated market. Other states remain interested in deregulation, but recently have adopted a more cautious approach in light of the 2000-2001 California experience where wholesale prices increased ten-fold between December 1999 and December 2000.[1] Most observers expect that deregulation of retail electricity

* William Hieronymus is Vice President, Charles River Associates, Inc. RA) and has been an economic consultant for thirty years, working on electricity restructuring internationally for the last 15 years. He has a Ph.D. from University of Michigan, 1969. Steve Henderson is Vice President, CRA and has been an electricity economist for twenty-five years. He served on the FERC staff from 1989 to 1996 and has a Ph.D. in Economics from the University of Wisconsin, 1975. Carolyn Berry has consulted on a wide range of issues in the electric industry. She served on the FERC staff from 1994 to 2000 and holds a Ph.D. from Northwestern University. Each of the authors has conducted market power analyses on behalf of clients that have been filed at the Federal Energy Regulatory Commission. The positions of the authors advanced in this paper reflect their own views and do not necessarily reflect those of CRA or its clients. This paper has not been supported through any outside funding.

1. *See generally* Paul Joskow & Edward Kahn, *A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market During Summer 2000: The Final Word* 10 (Feb. 4, 2002), *available at* http://econ-www.mit.edu/faculty/pjostow/files/Jostow-K.pdf. Given the volume of papers reviewing the California pricing experience, the paper assuredly will not be the "Final Word." Other examples of this literature are Joskow & Kahn, *A Quantitative Analysis of Pricing Behavior in* California's Wholesale Electricity Market During Summer 2000, Nat'l. Bureau of Econ. Res. (NBER) Working Paper 8157 (Mar. 2001), *available at* http://www.nber.org/papers/w8157; Joskow & Kahn, *A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market During Summer 2000* (July 5, 2001), *available at* http://econ.www.mit.edu/faculty/pjoskow/papers.htm; Scott Harvey & William Hogan, *On the Exercise of Market Power Through Strategic Withholding in California* (Apr. 24, 2001) (on file with author); Harvey & Hogan, *Further Analysis of the Exercise of Market Power in California* (Nov. 21, 2001), *available at* http://ksghome.harvard.eud/~.whogan.cbg.ksg/Further%20

markets will resume after the lessons of California have been learned and can be incorporated into market designs. The ongoing restructuring of the electricity industry raises interest in market studies not only in conjunction with deregulation, but also in the context of mergers and other asset transfers as market participants position themselves for success in the still-developing competitive power market. The market power implications of such asset transfers are subject to scrutiny by both the FERC and the Federal Trade Commission (FTC), as well as a number of state regulatory agencies.[2] As a result, federal and state regulators and federal and state antitrust officials have an interest in understanding the market power implications of particular deregulation programs and particular asset transfers.

This multiple jurisdiction over market power issues in electricity is partly a historical relic but also reflects the fact that electricity is a product that is "imbued with the public interest." Despite that it has been available to consumers for more than 100 years, it is regarded as an essential product and has been tightly regulated, not only in terms of price but also in terms of the reliability and conditions of supply. As politicians and regulators move to reduce their direct control over the sector, there is a valid concern that outbreaks of market power (or of market dysfunction for whatever cause) will cause the public to reject deregulation despite the general societal belief that competitive markets are inherently superior to regulated ones. There is a consensus within the industry that "one more California" will bring the process of industry restructuring to an abrupt halt.

This paper discusses various approaches for conducting prospective market power analyses in the electricity industry. The depth of the inquiry appropriately depends on the context. The two primary contexts are, first, mergers and acquisitions and, second, the granting by the FERC of the right to sell at essentially unregulated market prices instead of regulated cost-based prices. The paper does not explore market power analysis that arises in the context of an after-the-fact investigation into allegations of actual antitrust violations, such as price fixing or collusion. It also does not address vertical market power concerns as might arise from the ownership of gas pipelines or electric transmission—important topics that have their own quite different regulatory context and procedures. As such, this study's subject matter is hypothetical exercises of market power and the

Analysis%20of%20Exercise%20of%20Mkt%20Pwr%20in%20CA%2011-21-01.pdf; FEDERAL ENERGY REG. COMM'N, *Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities* (Nov. 1, 2000), *available at* http://www.ucei.berkley. edu /ucei/Recent_Presentations/Staff_Report_on_Western_Markets.pdf.

2. Until March 5, 2002, the Department of Justice (DOJ) and FTC shared responsibility for reviewing energy mergers. On that date, the agencies announced a new sharing of review responsibilities under which the FTC will review mergers in the energy area, including electricity. FEDERAL TRADE COMM'N & DEPT. OF JUSTICE, *Memorandum of Agreement Between the Fed. Trade Comm'n and the Antitrust Div'n of the U.S. Dept. of Justice Concerning Clearance Procedures*, *available at* http://www.ftc.gov/opa/2002/02/clearance/ftcdojagree.pdf (last visited Mar. 14, 2002) [hereinafter *Memorandum of Agreement*].

development of indicators that are useful in anticipating potential areas of concern that may arise in the course of replacing cost-of-service regulation with competition.

Prospective market analysis of the sort discussed here cannot be expected to identify a market power problem in advance with 100% accuracy. Instead, the best that can be achieved is to devise indicators that can provide early warnings so that additional study or protections can be provided. Any prospective study has a risk of committing either of the two errors common to the science of economic prediction. In particular, a prospective indicator of market power concerns may incorrectly identify a market-power concern where none exists (a false positive indication), or it may incorrectly indicate the absence of any market power concern where a problem does exist (a false negative indication). A false negative screening indicator presumably carries more risk than its false positive counterpart because, as a screening indicator, additional review potentially could reveal and correct for false positive indications, but such additional review presumably would not be undertaken (or undertaken with a lower frequency) in the case of a negative screening indicator that turns out to be false. For this reason, it is customary and appropriate to choose screening statistics that provide conservative indications. Accordingly, it is commonplace for regulators and antitrust authorities to use relatively low thresholds for concentration measures (or changes in concentration measures) in the first review step. Such thresholds serve to screen out cases clearly not likely to need additional review, in the expectation that additional review focused on fewer, more important cases will be able to eliminate the false positives.[3]

Screening thresholds or similar review criteria are needed regardless of the analysis employed in the development of prospective indicators. Two broad types of analyses are used. First, structural analysis is used to develop measures of market concentration, such as market shares or Herfindahl-Hirschman Indices (HHIs).[4] Second, behavioral analysis is used to estimate profitable price increases from hypothetical strategic behavior (such as a withholding strategy) in order to measure a supplier's market position or to gauge the competitive impact of a merger. Review criteria (*i.e.*, "safe harbor" limits) are generally available for structural analysis but not for behavioral studies. This is unfortunate because behavioral studies, although complex and expensive to conduct, have certain advantages over structural approaches. A recurring theme of this paper is that review criteria for behavioral studies are needed, if such studies are to be used by regulators or antitrust authorities, for the same reason they are needed for

3. Nonetheless, an important and explicit purpose of guidelines is to inform potential transactors how an agency is likely to judge the transaction. A too-cautious screen will have a chilling effect on transactions. Moreover, as discussed below, applicants' desire to avoid the delay and uncertainty of a contested hearing causes them to treat the screen as the "final word" on the FERC's review of a merger, offering mitigation to cure any screen failures.

4. An HHI is the sum of squared market shares for all suppliers in a market, and is a number from zero (atomistic competition) to 10,000 (monopoly).

structural studies—to avoid false positive indications. The paper explores possible review criteria, but acceptable criteria will need to be developed through a broad public comment process, such as the Notice of Proposed Rulemaking (NOPR) process that can be conducted by the FERC.

This paper is organized into seven sections. The next section discusses the various contexts in which market analysis arises in the electricity industry, followed by a brief discussion of the recent history of mergers and market pricing in this industry. The third section summarizes the review process used by the FERC and the antitrust agencies, and the fourth section discusses merger analysis—current practice and some possible alternatives. The fifth section focuses on market pricing in wholesale power markets and the ongoing change in FERC regulation of this important area. The sixth section addresses the monitoring and mitigation of market power and FERC's growing reliance on Regional Transmission Organizations (RTOs) to assist in this task, while some concluding observations and suggestions are offered in the final section.

I. CONTEXT OF MARKET ANALYSES

The way in which electricity markets are studied prospectively for market power is influenced substantially by the role and historical context of the agency addressing the issue, recent events coloring the review (such as the California experience), and the existence of detailed data on the electricity industry that allows analytical approaches not feasible in other industries. Moreover, market power studies in this industry reflect several unique characteristics that distinguish electricity markets from others. Electricity cannot be stored, and so aggregate supply and demand must be in equilibrium at all times. As electricity markets are deregulated, more and more of the real-time balancing function is no longer performed by traditional utilities that absorb the costs and recover them on a rolled-in basis under cost-of-service regulation, but instead is performed by independent generators that must be compensated directly for the service. The importance of spot markets for electricity will grow as a result, and thus the potential for exercising market power in such emerging markets is an increasing policy concern. Moreover, most end-users have simple energy-only meters that accumulate electricity use over a month (or the period between meter readings), and cannot be used to convey price information over a shorter interval, such as a particular hour or the peak period within a day when wholesale prices are higher. This lack of metering does not allow demand to respond to price.[5] Individual utilities in the industry have been nurtured for almost 100 years within geographically compact franchise service territories, the legacy of which is a series of locally concentrated markets that can be expected to become less concentrated under de-

5. This is commonly referred to as a condition of "inelastic demand." In actuality, demand is not totally inelastic, although the elasticity may be small. Rather, the existing set of price-responsive demands is not confronted with prices that reflect hourly market conditions due to the lack of necessary metering.

regulation, but only after several years.

Apart from industry characteristics, the agency addressing particular market power issues can make a difference because the FERC and the antitrust agencies (Department of Justice (DOJ) in particular) appear to study mergers differently.[6] In broad theory, the approach used by the federal agencies is quite similar. FERC has adopted the DOJ/FTC *Horizontal Merger Guidelines* as a general matter.[7] As a result, all of the agencies define relevant product markets, define relevant geographic markets, and use HHIs indicators as a screen.[8] In practice, however, the FERC and the DOJ appear to differ in how the *Guidelines* are implemented. The FERC screen relies on structural analysis of market shares and HHIs that are developed using a so-called delivered price test, as discussed later.[9] The delivered price test abstracts from all uses of electricity except those in a narrowly defined destination market, which ignores several important realities of electricity markets. In comments filed with the FERC, the DOJ has expressed disagreement with some aspects of this implementation of the guidelines. More substantially, despite being a sponsor of the *Guidelines*, the DOJ's primary approach to mergers has been behavioral, asking questions about the ability and incentive to increase prices rather than simply structural questions.[10] Moreover, the agency recently has begun to focus on formal behavioral analysis in evaluating at least some mergers and acquisitions in the Hart-Scott-Rodino (HSR) process. This involves the use of simulation modeling in order to estimate the impact of a merger on profitable price increases achievable through strategic behavior. The FERC expressed an interest in behavioral modeling through a notice-and-comment procedure in 1998, but has not yet adopted any modeling requirements in its filing regulations.[11]

Apart from mergers, the FERC uses market analysis in evaluating requests by public utilities for authority to sell power in wholesale markets at

6. We refer here to the antitrust agencies even though the FTC will review electricity mergers in the future. *See generally Memorandum of Agreement, supra* note 2. Our experience is based on past reviews conducted by the DOJ. Future FTC review may develop differently.

7. Order No. 592, *Inquiry Concerning the Comm'n's Merger Policy Under the Federal Power Act*, F.E.R.C. STATS. & REGS. ¶ 31,044 (1996) [hereinafter *Merger Policy Guidelines*] (adopting the DOJ & FTC *Horizontal Merger Guidelines* (Apr. 2, 1992)). *Horizontal Merger Guidelines* are available at http//:www.ftc.gov/bv/docs/horizmer.htm.

8. The DOJ/FTC *Horizontal Merger Guidelines* provide for the following thresholds in evaluating horizontal mergers. If the post-merger HHI is less than 1,000, the merger is not considered likely to create a competitive concern and additional review typically would not be needed. If the post-merger HHI is between 1,000 and 1,800 (a moderately concentrated market), additional review would not be needed if the change in HHI is less than 100 points. If the post-merger HHI exceeds 1,800 (a highly concentrated market), additional review may be needed if the change in HHI is greater than 50 points. *Supra* note 7.

9. *See generally infra* note 33.

10. Based on past practice at the DOJ, not necessarily to be continued at the FTC.

11. Notice of Request for Written Comments and Intent to Commence a Technical Conference, *Inquiry Concerning the Commission's Policy On the Use of Computer Models in Merger Analysis*, F.E.R.C. Docket No. PL98-6-000 (Apr. 16, 1998).

a market-based rate. The FERC has not deregulated wholesale power markets, but rather has broad discretion under section 205 of the Federal Power Act (FPA) as to how it should regulate such sales.[12] Generally, FERC is willing to approve wholesale rate authority on either cost-based or market-based grounds. Cost-based rates typically must be justified on the basis of an applicant's own costs, although the costs of others may serve as a benchmark in some cases. Market rates must be justified by a showing that the seller lacks market power, which is not the same as showing that the market-as-a-whole is competitive. A market may include some suppliers with large market shares so that the market might not be viewed as workably competitive, but a particular supplier nonetheless could be authorized to sell at market rates if it lacks market power, *i.e.*, has a sufficiently small market share. Traditionally, the FERC has accepted market shares up to 20% to 30% as evidence that the supplier does not dominate a market and thus lacks market power.[13,14] Unlike the area of mergers and acquisitions, where the FERC shares regulatory responsibility with other federal agencies and often with commissions in the affected states, the FERC has sole authority in regulating wholesale electric rates.

State regulators and legislatures are responsible for retail electricity regulation. Approximately half of the states have either started a deregulation program or are actively considering one.[15] California, of course, was an early pioneer, adopting a retail deregulation program in 1996. Until May of 2000, the market was well behaved, apart from some anomalies that were permitted or even required by market rules that had not yet been fine-tuned. However, beginning in May 2000 and extending through the spring of 2001, wholesale prices in the California market reached unprecedented high levels, increasing from a typical $20 to $50 per megawatt-hour (MWh) to a level that averaged $100 to $300 per MWh, with prices at much higher levels at times. Combined with local supply shortages that forced the California Independent System Operator (ISO) to cut off electricity to wide areas through the implementation of rolling blackouts, these

12. See Farmers Union Cent. Exch. v. FERC, 734 F.2d 1486 (D.C. Cir. 1984) for a discussion of the concept of market-based pricing under the FPA.

13. The FERC's threshold test was initially set at a 20% market share. *See generally Louisville Gas & Electric Co.*, 62 F.E.R.C. ¶ 61,016, at 61,146 (1993). Subsequently, the FERC approved market-based rate applications for entities whose market shares exceeded 20%. *See also Southwestern Power Service Co.*, 72 FERC ¶ 61,208, at 61,966-67 (1995) (25% market share for installed capacity); *Southern Co. Services, Inc.*, 72 F.E.R.C. ¶ 61,324, at 62,405 (1995) (affiliated public utility had a market share for installed capacity somewhat above 20% in thirteen of the fifteen markets examined); *USGen Power Services, L.P.*, 73 F.E.R.C. ¶ 61,302, at 61,845 (1995) (affiliate's market share was above 20% for installed capacity in seven out of eight markets with a maximum of 26%) and *Vantus Energy Corp.*, 73 F.E.R.C. ¶ 61,099, at 61,315 (1995) (affiliate's market share was above 20% for installed capacity in seven out of eight markets with a maximum of 26%).

14. This standard was established in the context of the so-called hub-and-spoke approach, which does not necessarily define a proper antitrust market (narrower in some instances, broader in others). *See generally* discussion *infra* note 58.

15. For a summary of state deregulation activities, see U.S. Dept. of Energy, Energy Info. Admin., *Electric Power Industry Restructuring and Deregulation, available at* http://www.eia.doe.gov/cneaf/electricity/page/restructure.html (last visited Mar. 14, 2002).

high prices have forced a re-examination of the state's deregulation commitment. In the near term, California will return to a regulated retail market in which state agencies will assume much of the power supply responsibility formerly assigned to the regulated utilities. A consequence of the California experience is that many other states that were considering deregulation programs of their own have now reconsidered and have delayed, in some cases indefinitely, the introduction of competition. At the FERC, these events (in conjunction with other motivations) have caused the agency to change course in the way that market power is analyzed in support of market rates for sales of wholesale power. As discussed later, the FERC has replaced its traditional hub-and-spoke analytical approach with a Supply Margin Assessment (SMA) as an interim matter.[16] In the longer term, the FERC is considering how best to revise its analytical requirements.

Another important element that influences market analysis in the electricity industry is the wealth of data that is publicly available. These data can support substantially more complex analyses than typically can be conducted for most industries in the United States. Because electric utilities were regulated monopolies, they lacked the usual commercial sensitivity concerning the release of detailed data. The regulatory process made such data public, often in conveniently summarized form. Information on the size and characteristics of power plants, area-by-area consumption on an hourly basis, the variable cost of generation, the rate for transmission service to deliver power, and transmission network connections and limits can be used to support market power analyses ranging from simple structural models to complicated simulation models of hour-by-hour behavior. Much of this dataset can be expected to remain in the public domain for some time in the future, although some of it is commercially sensitive and may become confidential over time. Even if data are withdrawn, the system changes sufficiently slowly that data already in the public domain can be used for years. In any case, the availability of such information supports, and indeed invites, the construction of complex market models.[17] Much can be learned from such models, but they remain merely models—abstractions of reality that must be tempered by judgment when assessing the likelihood of future market power abuses.

The topic of market power is also related to the FERC's efforts to restructure the transmission portion of the electricity industry by encouraging (some would say coercing) public utilities to form and join an independent RTO. While the primary purpose of these RTOs is the provision of transmission service in an open, non-discriminatory, and standard way,

16. *See generally* discussion at *infra* note 60.

17. A typical market study assumes that a generator's variable running costs are its short-run marginal costs. This assumption becomes the benchmark against which market performance is measured. The correct measurement is short-run marginal opportunity costs, which would involve the value of some inputs, such as water and pollution credits, that must be rationed over time. Such considerations are well known but almost impossible to address in a market study performed using only publicly available data.

these organizations also will have a responsibility to monitor the performance of wholesale markets and to discipline behavior through market mitigation actions, both under the watchful eye of the FERC itself.[18] The monitoring and mitigation functions of an RTO will be overseen in the first instance by an independent monitor, who will report to the FERC and be supported by the RTO's internal monitoring staff. These monitoring and mitigation protections can be expected to be a feature of wholesale markets for the foreseeable future, although as wholesale markets mature the need for such protections eventually may wane because of responsive demand and geographically dispersed ownership of generation. In the meantime, it seems clear that the FERC will rely to some extent on the RTO monitoring and mitigation function to provide a measure of discipline in wholesale markets. This, in turn, reduces, but does not eliminate, the need for the FERC to devise market screens that prevent all potential abuses of market-based pricing authority. With the RTO monitoring and mitigation function in place, the FERC can more confidently move away from cost-based pricing and its attendant inefficiencies to a market-based regime in which prices that cannot be disciplined completely by the existing state of competition nonetheless can be expected to remain at reasonable levels.

The FERC's current emphasis on RTO market monitoring, and its plan to backstop such monitors with its own new fifty-person monitoring unit, signal several important aspects of the Commission's current posture. First, market power concerns have assumed a much-heightened priority since the California debacle, blamed by the state's officials and others on alleged market power abuse and weaknesses in FERC oversight.[19] Second, the emphasis on market monitors rather than a traditional reliance on complaints to deal with allegations of misbehavior may reveal an intent to micro-regulate behavior. Further, it is expected that market power mitigation features in the "standard market design," a template for RTOs to be released later this year, will be intended to prevent, rather than simply detect, behaviors judged inconsistent with the public interest.

Finally, it is clear that electricity regulators, especially the FERC, view market power more broadly than actions covered by the antitrust laws.[20] Under the antitrust statutes, it is not generally illegal to engage in unilateral behavior that raises market prices if the firm's market position has been obtained legally. That is, it is illegal to monopolize through certain actions, such as price fixing or predatory pricing, but a monopoly position that is achieved by legal means, such as by being more efficient than com-

18. Federal Energy Reg. Comm'n Staff, Working Paper on Standardized Transmission Service and Wholesale Electric Market Design, F.E.R.C. Docket No. RM01-12-000 (Mar. 18, 2002).

19. Letter from Economists to President George W. Bush (May 25, 2001) (signed by Roger Bohn, Severin Borenstein, James Bushnell, Peter Cramton, Alfred Kahn, Paul Joskow, Alvin K. Klevorick, Robert Porter, Carl Shapiro, and Frank A. Wolak), *available at* ftp://zia.stanford.edu/pub/papers/economists.let.pdf.

20. Sherman Act, 15 U.S.C. §§ 1-2 (1982); Clayton Act, 15 U.S.C. § 14 (1982).

petitors, can be used to charge higher than competitive prices.[21] A FERC Staff Strawman Paper indicates that the FERC would include antitrust violations as examples of illegal market power but would not stop there.[22] The FERC Staff Strawman asserts that unilateral withholding (either physical or economical) would result in prices that would not be just and reasonable under the Federal Power Act (FPA).

It is not surprising that the FERC would adopt such a strict position given its traditional role in regulating wholesale prices and its broad authority over conduct. Moreover, it faces an industry structure that evolved without any anticipation of competition. As of the mid-1990s, the industry was composed of roughly 100 major utility companies (and hundreds of much smaller ones), each of which owned substantially all of the generation in its service area. Transmission was built primarily for reliability purposes, not to serve as a highway for wide-area competition. The FERC has little direct power to modify that structure. While entry by merchant generators and voluntary or state-mandated divestitures of generation have created competitive market structures in some areas, this is far from universal.

The experience of the past decade indicates that there are no fundamental technical or economic barriers to creating a competitive generation market structure. Moreover, the pattern of entry has been substantially deconcentrating. With a few notable exceptions, the existing utilities have not sought to restrict entry into their historic service areas. The structure of the entrants themselves has thus far been consistent with an evolving competitive market structure. Their assets are, in the main, widely dispersed and none of them controls more than a small percentage-point share of generation nationally, or in any area. The state regulators and legislators who have primary control over the introduction of competition to serve the customers in their states have, for the most part, been sensitive to the need to first ensure a competitive market structure. The FERC policy is predicated on its belief that the industry will evolve, in a relatively short period of time, into a structure that is consistent with very light-handed regulation of wholesale markets.

In this context, the FERC's priorities can be summarized as follows. First, create a market context that is consistent with competition. This means, in particular, ensuring that transmission is not an impediment to entry and to fair competition. It also means creating structures that allow economies of scale and scope in system operation to be maintained in the

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21. United States v. Grinnell Corps., 384 U.S. 563, 570-71 (1966) (The offense of monopoly under Section 2 of the Sherman Act has two elements (1) the possession of monopoly power in the relevant market and (2) the willful acquisition or maintenance of that power as distinguished from growth or development as a consequence of a superior product, business acumen, or historic accident).

22. Federal Energy Reg. Comm'n Staff, Strawman Discussion Paper for Market Power Monitoring and Mitigation Panel, Presentation to the Technical Conference on Market Structure and Design, F.E.R.C. Docket No. RM01-12 (Feb. 7, 2002), *available at* http://www.ferc.fed.us/electric/rto/mrkt-strct-comments/mrkt-strct-comments/straw-paper.pdf [hereinafter FERC Staff Strawman].

context of dispersed ownership of generation. The FERC's vehicle for this goal is the policy of forcing utilities into RTOs that will control transmission and operate the electric system. Second, policies on mergers and acquisitions are intended to ensure that the current "urge to merge" will not reconcentrate the industry where it is competitive or slow deconcentration of it where it is not. Third, essentially stop-gap policies to regulate or quasi-regulate prices are intended to ensure that unacceptable outcomes in the near term will not end public and political support for restructuring.

It also is important to recognize that the statutory framework in which the FERC regulates rates has not changed one iota in the past decade. The FERC retains an obligation to ensure that wholesale prices are "just and reasonable" and that the variety of actions that it must approve, including mergers, are consistent with the public interest. Its precedents and such court decisions as are relevant are grounded in a period of rate regulation. A too-lenient attitude toward the outcomes of competition would be subject to challenge, just as the Securities and Exchange Commission (SEC) recently was challenged successfully for its failure to enforce portions of the Public Utilities Holding Company Act that it, and most experts, believe should be repealed.[23]

For these reasons, it is entirely understandable, and even necessary, that the FERC, during the transition from regulation to competition, would have a much more active view of its role in enforcing competitive behavior and a much stricter view of what market behavior is acceptable in comparison with the antitrust laws. This leads to some approaches as to how market power might be analyzed that may appear strange to antitrust practitioners, but are consistent with the FERC's obligations under the FPA. Some practical drawbacks arising from FERC's view of its obligations are discussed in the section on monitoring and mitigation below.

II. RECENT APPLICATION OF ELECTRICITY MARKET STUDIES

The practical importance of accurate assessment of market power in the electricity industry can be gauged by reviewing recent mergers and market-pricing experiences.

A. Electricity Mergers

Prior to the 1990s, mergers among electric utilities were uncommon.[24] With a few notable exceptions (such as AEP's long-delayed completion of

23. National Rural Elec. Coop. Ass'n v. SEC, 276 F.3d 609 (D.C. Cir. 2002), (AEP merger with CSW not shown to satisfy integration requirements of the Public Utility Holding Company Act of 1935 (PUHCA), 15 U.S.C. § 79 (2001)).

24. Early in the history of the U.S. electric utility industry, there was a tremendous wave of consolidation among small utilities that created the checkerboard landscape of the modern utility service areas. This initial consolidation created vast, often geographically disjoint, utility holding companies, spurring a comprehensive inquiry into the industry by the FTC in 1928 and passage of PUHCA in 1935. This led to the breakup of some of these utility holding companies and the ending of this first era of industry consolidation.

its acquisition of Columbus and Southern Electric Co. in the 1980s), the landscape of public utilities was relatively stable since the 1930s. This has changed dramatically since the PacifiCorp merger in 1989 (combining Utah Power & Light with Pacific Power & Light as separate divisions of PacifiCorp so as to avoid designation as a Registered Holding Company under PUHCA). Since that time, the FERC has reviewed about 100 merger applications. Table 1 lists twenty-six of these that involved horizontal mergers of electric utilities, each of which had combined assets exceeding $5 billion. These mergers involved a combined book value of assets of more than $500 billion. Not all of these mergers were completed, such as the PECO-PPL (1995) and Entergy-FPL (2001) proposals.

The other mergers in the industry during the 1990s have involved vertical mergers of electric utilities with fuel supply companies, *e.g.*, natural gas pipeline companies, such as the pending merger of Duke Energy and Westcoast Energy, recently cleared by both the FERC and the FTC. All 100 of the merger applications submitted to the FERC have a combined book value of about $1 trillion.

Apart from the notable increase in utility merger activity that has characterized the 1990s, it is difficult to generalize about the mergers themselves. About half of the mergers were mainly horizontal within the U.S. electricity sector, while the remainder either involved vertical mergers or the acquisition of a public utility by an international company (*e.g.*, Scottish Power acquiring PacifiCorp) or by a non-traditional utility (*e.g.*, AES acquiring Indianapolis Power & Light and Central Illinois Light Co.).

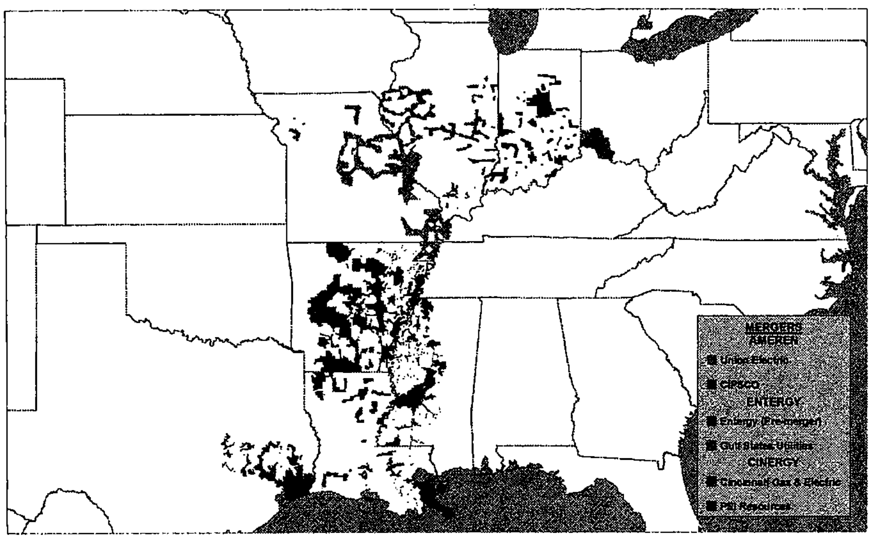
TABLE 1
Electric Utility Mergers
(Book Value Exceeding $5 Billion through November 30, 2001)

Buyer	*Seller/Acquired/ Merged*	*New Company*	*Date Completed*	*Combined Assets ($B)*
Peco Energy Co.	Unicom Corp.	Exelon	23-Oct-00	42.2
FPL Group	Entergy	Not Completed	2-Apr-01	40.9
First Energy	GPU Inc.	First Energy	7-Nov-01	37.2
AEP Resources	Central and Southwest Corp.	AEP	15-Jun-00	33.2
AES Corporation	IPALCO	AES Corporation	27-Mar-01	31.0
PECO Energy	PPL Resources	Not Completed	01-Jun-95	27.2
Consolidated Edison	Northeast Utilities	Consolidated Edison	15-Mar-01	24.8
Northern States Power	Wisconsin Electric & Power	Not Completed	01-May-97	22.6
Entergy	Gulf States Utilities	Entergy	01-Dec-93	21.4
Utah Power & Light	Pacific Power & Light	PacifiCorp	31-Dec-89	19.6
Ohio Edison	Centerior Energy	First Energy	01-Nov-97	19.1

Consolidated Edison	Orange & Rockland Utilities	Consolidated Edison	08-Jul-99	15.7
Northern States Power	New Century Energies	Xcel Energy	17-Aug-00	15.1
Carolina Power & Light	Florida Progress	Progress Energy Inc	30-Nov-00	14.5
PEPCO	Conectiv	Not Completed	26-Sep-01	13.5
Dynegy	Illinova	Dynegy	02-Feb-00	12.9
Allegheny Power	DQE, Inc.	Not Completed	03-Dec-99	11.9
CalEnergy	Mid-American Energy	CalEnergy	12-Mar-99	11.8
AES Corporation	Cilcorp	AES Corporation	18-Oct-99	11.3
Western Res ources	Kansas City Power & Light	Western Resources	03-Jan-00	11.0
Northeast Utilities	PS New Hampshire	Northeast Utilities	01-Jun-92	10.6
Energy East	RGS Energy	Energy East	26-Sep-01	9.6
Union Electric Company	CIPSCO	Ameren Corporation	01-Dec-97	8.6
Sierra Pacific Resources	Portland General	Not Completed	26-Apr-01	8.5
KeySpan	Eastern Enterprises	KeySpan	09-Nov-00	8.3
Cincinnati Gas & Electric	PSI Resources	Cinergy	01-Oct-94	8.1
Energy East	CMP Group, Inc.	Energy East	01-Sep-00	7.2
Utilicorp United	Empire District Electric	Not Completed	03-Jan-01	7.0
National Grid USA/NEES	Eastern Utilities Associates	National Grid USA/NEES	19-Apr-00	6.6
Public Service of Colorado	Southwestern Public Service	New Century Energies	01-Aug-97	6.6
Utilicorp United	St. Joseph Power & Light Co.	Utilicorp United	29-Dec-00	6.3
Northeast Utilities	Fletcher Electric Light	Northeast Utilities	01-Sep-92	6.2
SCANA Corp	PSC Of North Carolina	SCANA Corp	10-Feb-00	5.9
Delmarva Power	Atlantic Energy	Conectiv	01-Feb-98	5.7
Kansas Power & Light	Kansas Gas & Electric	Western Resources	01-Mar-92	5.2
New England Electric System	Nantucket Electric	New England Electric System	01-Mar-96	5.2
Wisconsin Energy	Eselco, Inc.	Wisconsin Energy	01-May-98	5.1
WPL Holdings Inc.	IES Industries	Interstate Energy	01-Apr-97	5.0
			Total	**562.6**

While there are exceptions, the mergers in the early 1990s tended to involve neighboring utilities. This is illustrated in Figure 1 using three examples (Ameren in Illinois-Missouri, Entergy in Louisiana-Texas, and CINergy in Indiana-Ohio).

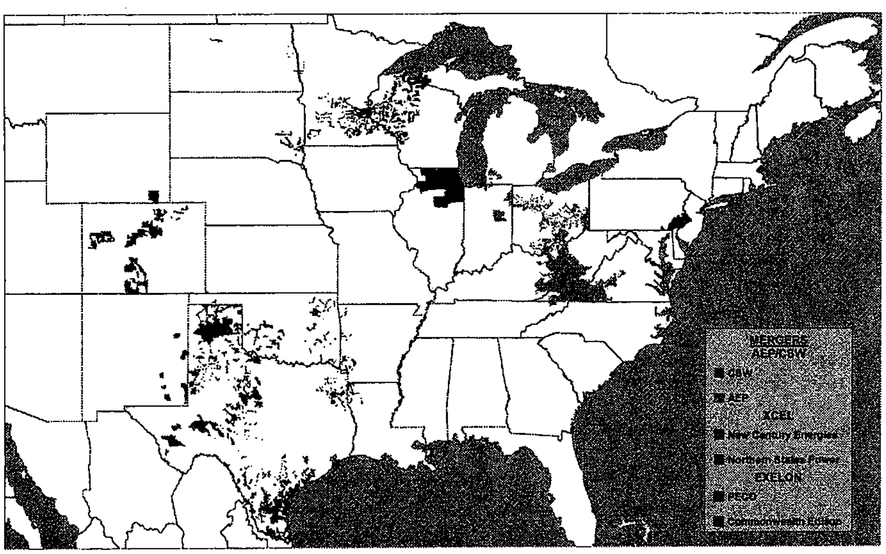
FIGURE 1
Examples of Early Mergers (1991-1995)



Source: RDI/Platts PowerMap, 2001.

In contrast, mergers since 1996 have tended to involve utilities that are separated by an intervening utility. Figure 2 illustrates this using the mergers that formed Xcel (Minnesota-Colorado-Texas Panhandle), Exelon (Chicago-Philadelphia), and AEP (Ohio-Texas).

FIGURE 2
Examples of Recent Mergers (1996-2001)



Source: RDI/Platts PowerMap, 2001.

This may have been partly the result of the FERC adopting its delivered price test in 1996, as discussed below.[25] The test is difficult for neighbors to pass, but relatively straightforward to pass if at least one transmission wheeling transaction over an intervening utility is needed to move power between the merging utilities. Mergers involving more than one wheeling transaction are not common because of the integration requirement of the PUHCA, and even a single wheeling transaction being used to fulfill this integration requirement has recently been challenged successfully in court and sent back to the SEC for additional review.[26] The urge-to-merge has recently slowed, partly because of the economic downturn and perhaps partly because of the need to sort through the implications of the Enron bankruptcy.

B. *Market-Based Pricing Experience in Wholesale Markets*

For the most part, wholesale electricity prices have remained steady through the deregulatory process. There have been certain episodes, however, during which wholesale prices have spiked to unprecedented levels. These price events were largely caused by supply/demand imbalances, but were exacerbated by the rules and procedures governing market operations—and sometimes the design of the market itself.

The Midwest, New England, and California markets each have experienced temporary periods with exceptionally high prices. In each case a convergence of a number of factors—unusually high temperatures, plant outages, low hydro production, transmission constraints, high gas prices, *etc.*—triggered a price spike. The lack of a vibrant demand-side market, which could discipline price spikes caused by insufficient supply, is a primary culprit. However, there are other lessons to be learned from these events that will help in refining the design of markets and the rules that will ensure reasonable prices.

1. Midwest Price Spikes

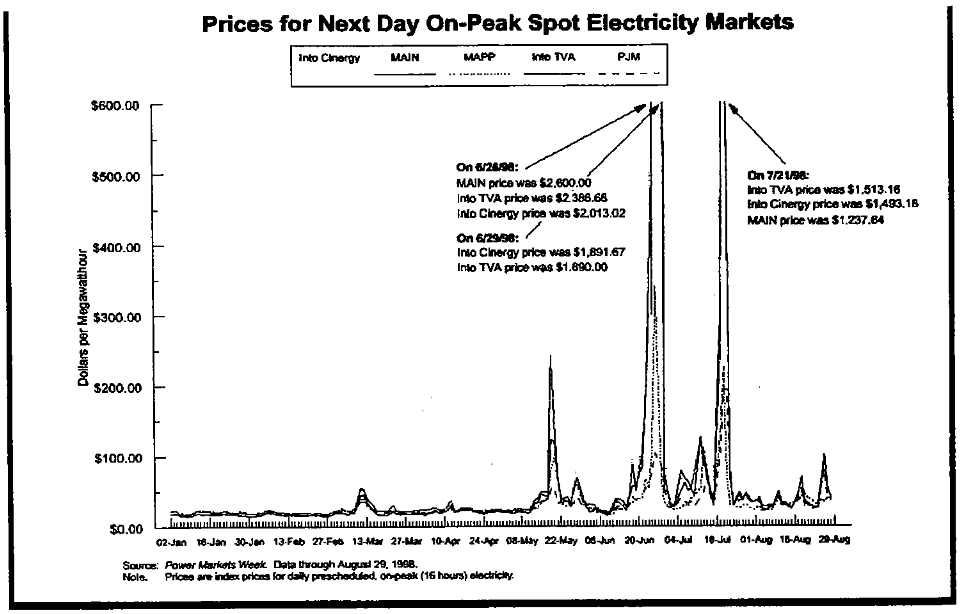
The Midwest had its first experience with price spikes in the latter part of June 1998. On June 26, 1998, as shown in Figure 3, the price in the region encompassing Illinois and portions of Missouri, Wisconsin, Iowa, Minnesota, and Michigan[27] reached $2,600 per MWh (summer peak wholesale prices typically may reach about $100 per MWh by comparison). At the same time, prices into Tennessee Valley Authority (in Tennessee) and CINergy (in Ohio) reached $2,386 and $2,013 per MWh, respectively. On June 29, 1998, and again on July 21, 1998, prices spiked again to more than 15 times historical levels.

25. *See generally* discussion *infra* note 33.

26. National Rural Elec. Coop. Ass'n v. SEC, 276 F.3d 609 (D.C. Cir. 2002). *See generally* 15 U.S.C. § 79j(c)(2) (2001) for the integration requirements of the PUCHA.

27. This region is designated as the Mid-America Interconnected Network, Inc. (MAIN) of the North American Electric Reliability Council.

FIGURE 3[28]



Numerous factors have been identified as contributing to these price events. The Midwest and surrounding regions experienced extremely hot temperatures over a prolonged period. This eroded the usual power-sharing opportunities that generally exist among these areas. Numerous plants and transmission lines were unexpectedly out due to weather-related damages. Transmission constraints, exacerbated by the inter-utility procedures used to manage congestion—Transmission Loading Relief, (TLRs)—reduced the ability to move power through the system, and defaults on contracts reduced trader confidence in the market. In general, good communication of prices and other market information was lacking due to inexperienced market participants and the lack of an infrastructure to allow the exchange of such information.

The FERC staff concluded at the time that there was a need for more real-time operational and market data to be made available to the FERC and to the industry in general.[29] They also concluded that there was a need for more regional coordination in generation and transmission planning as well as operation of the system. Certainly the event was a clear signal to market participants that hedging instruments were a necessary part of the new marketplace. From a regulatory perspective, it could be expected that the incentives of market participants could result in market manipulation during temporary periods of scarcity, although Commission staff con-

28. OFFICE OF THE CHIEF ACCOUNTANT ET AL., Staff Report to the Federal Energy Reg. Comm'n on Causes of Wholesale Electric Pricing Abnormalities in the Midwest during June 1998 (Sept. 22, 1998), *available at* http://www.ferc.gov/electric/mastback.pdf.

29. *Id.*

cluded at the time that the enforcement mechanisms in place were sufficient to remedy any abuses.

2. New England

On May 8, 2000, prices in the market managed by the Independent System Operator—New England (ISO-NE, an agent of the New England Power Pool) reached an unprecedented $6,000 per MWh. Again, as in the Midwest, there was a temperature component in the story, but the ultimate cause in this case was information problems and errors in computer software.[30]

New England and surrounding areas experienced record-breaking temperatures that spring, a season characterized by low levels of demand and large amounts of generation shut down to perform periodic maintenance. Due to weather-related high demand and low generation availability, ISO-NE, on May 8, found itself short of the capacity needed to meet demand plus reserves. ISO-NE, under its operating protocols applicable in such circumstances, was not allowed to purchase operating reserves from outside the system. Thus, ISO-NE was obligated to draw on capacity from within the system; this actually required reducing system output so that ISO-NE units would have spare capacity available if needed. In turn, ISO-NE was required to purchase additional energy from outside.

For reasons peculiar to its rules that are beyond the scope of this paper, the lowest-priced offer that ISO-NE could accept was $6,000 per MWh from a generator in New York.[31] Available to ISO-NE was an offer from New York to supply installed capacity with the energy component (as part of the capacity offer) priced at $6,000 per MWh. For other market rules-related reasons, this accepted offer would become the price of the marginal unit and hence set the price for all spot sales in New England, only if it were justified by its opportunity costs in New York. ISO-NE examined the forecast prices posted on the NYISO's web site and found that some clearing prices were forecast to be as high as $3,387 per MWh. Given this information, ISO-NE accepted the external offer, which set the price in ISO-NE at $6,000 per MWh during four hours. It was found after-the-fact that the forecast prices in NYISO were wrong and should have been closer to $331 per MWh, one tenth of the level actually posted.

Although the price spike was transitory in nature, there were large impacts on certain individual buyers. Bangor Hydro (a small utility in Maine), for example, incurred costs of approximately $2.6 million over the four hours, which it ultimately had to collect from its customers. Other

30. Federal Energy Reg. Comm'n Staff, *Investigation of Bulk Power Markets, Northeast Region* (Nov. 1, 2000), *available at* http://www3.ferc.fed.us/bulkpower/northeast.pdf.

31. While market rules are not the focus of this paper, it is an object lesson that the New York generator intended to offer "capacity" to the New England market, but did not intend to provide energy. However, ISO-NE rules required suppliers of capacity also to offer energy. The $6,000 per MWh price was not an example of an attempt to exercise market power; rather it was set with the intention of assuring that the New York unit would *not* be called to provide energy to ISO-NE.

buyers also suffered from this event, as it caused a dramatic jump in forward prices that took months to settle out of the system. In the wake of this experience, ISO-NE changed its operating protocols to allow it to mitigate energy bids associated with external installed capacity offers during emergency conditions. ISO-NE also adopted a price cap of $1,000 per MWh to apply during the same periods.[32]

3. California

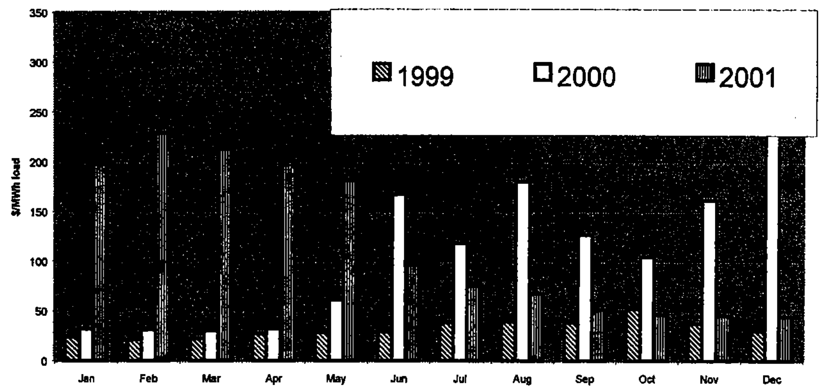
In the early summer of 1998, California experienced a dramatic price run-up in its ancillary services or short-term capacity markets, marked by a $9,999 per MW price in the replacement reserve market. This was a transitional event caused by confusion over the move from cost-based to market-based bidding and a lack of supply in these capacity markets. The ancillary services markets were originally set up under cost-based bidding since there was no assurance at the time that they could operate competitively. In lieu of moving the whole market from cost-based to market-based bidding, the FERC, at the sellers' request, granted market-based rate authority to some participants, while others continued to bid into these markets at cost-based rates or were excluded from them altogether. These markets, which had opened a couple of months before, were thin; participants were just getting used to how they worked. Additionally, market rules prevented suppliers outside the control area from participating. Tight supply, rigid mandatory purchase obligations placed on the ISO, and partial deregulation of bid prices provided a formula for a price event. As in New England, California responded by changing the market rules and adopting price caps.

The most prolonged and damaging episode of high prices occurred in California over a one-year period from approximately May 2000 through May 2001. The lack of precautionary measures, the convergence of a number of infrequent events, and the inability of market and government institutions to respond to the crisis in a timely manner forced the largest publicly owned utility in the state, Pacific Gas & Electric, into bankruptcy; undermined the state-sponsored Power Exchange and forced it out of business; obligated the state to step in and incur billions of dollars in debt in order to secure energy for its residents; and inflicted a severe blow on retail competition and its associated benefits for the indefinite future. Figure 4 shows average monthly wholesale electricity costs in California (including the costs of both energy and ancillary services) for 1999 through 2001.

32. For additional discussion of New England markets, see David B. Patton, Potomic Economics, *An Assessment of Peak Energy Pricing in New England During Summer 2001* (Nov. 2001), ***available at*** http://www.iso-ne.com/special_studies/Summer_2001/Assessment_ by_Independent_ Market_Advisor.pdf.

FIGURE 4

California Wholesale Electricity Costs, 1999-2001



Source: California ISO Department of Market Analysis.

There were numerous causes of the California crisis, setting aside any allegations of market power abuse:

- Above-normal temperatures across the whole western part of the U.S.;
- A reduction in hydro resources from record high previous years to near-record lows;
- Reduced availability of imports and dramatic increases in emissions permit prices;
- Heavy reliance on gas resources and gas prices that rose significantly in the Spring of 2000 and to record high levels starting in late November 2000 and continuing through the first part of 2001;
- A crisis in creditworthiness as the debts of buyers mounted beyond even the vast equity of the state's two large utilities;
- Lack of hedging by the public utilities of power purchases—nearly all their needs were purchased in the volatile spot markets;
- No pass-through of price increases to most retail customers, since their prices were fixed at low guaranteed levels during the transition; and
- Lack of ability to incorporate demand-side price response to discipline market prices.

The market monitors in California were unable to implement protective measures during the crisis. They were caught between the conflicting goals and jurisdictions of the state and federal governments. By their very nature, governmental and regulatory institutions are slow to respond to these types of events. There was little, in any case, that the ISO could do about the underlying fundamentals that created the situation. In particular, with no action taken by state officials to encourage customers to reduce demand until well into the crisis, the ISO could do nothing but buy power at any price on behalf of the utilities in order to keep the lights on.

While many lessons have been learned from the California experience, it is important to recognize that there is no other region of the country where it is likely ever to be replicated. The key distinction between what happened in the West in 2000-01 and the price spikes that have occurred elsewhere was that California prices stayed elevated for an entire year. This is traceable to the fact that so much of western capacity (principally but not solely hydroelectric) is energy limited. That is, the constraint on output is not so much the size of the generating turbines but the amount of water available. Unlike fossil output, hydroelectric output can be moved around in time. Hence, while prices in a fossil system can spike due to a shortage, such spikes are inherently brief. With a hydro system, particularly one that is uncharacteristically short of water, inter-period arbitrage will cause prices to rise during all periods. Operators will, and should, reserve output for high-load, high-price periods. If, as is the case in the West, hydroelectric capacity is a major share of all capacity, the concentration of its availability into only a small share of hours will cause shortages to occur in other hours as well. Thus, by the winter of 2000-2001, prices were at a high and nearly uniform level around the clock.

It is fair to say that the lessons of the California electricity pricing experience will continue to be learned for some time, and that retail deregulation has suffered a setback of at least a few years.[33]

III. REVIEW PROCESS AT THE FERC AND THE DOJ/FTC

A. *Federal Energy Regulatory Commission*

The FERC, under section 203 of the FPA, must approve all mergers of jurisdictional public utilities.[34] The Commission has is a formal review process with well specified filing requirements and guidelines for corporate applications.[35]

Prior to filing a merger application with FERC, merging parties may

33. For additional discussion of the California experience, see Severin Borenstein et. al., Diagnosing Market Power in California's Deregulated Wholesale Electricity Market, Univ. of Cal. Energy Inst. Working Paper PWP-064 (Aug. 2000), available at www.haas.berkely.edu/groups/cps/WPs/99-7-pwp064.pdf; Severin Borenstein et. al., "Price Convergence in California's Deregulated Electricity Market," Presented to the U. of Cal. Energy Institute Conf. (Mar. 2000) (on file with author). *See also* discussion and works cited *supra* note 1.

34. Jurisdictional public utilities are those utilities that own FERC jurisdictional facilities. The FERC has jurisdiction over all facilities, except generating facilities, used in the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce.

35. *See generally Merger Policy Statement, supra* note 7. *See also* Order No. 642, *Revised Filing Requirments Under Pt. 33 of the Comm'n's Regs.*, F.E.R.C. STATS. & REGS. ¶ 31,111 (2000).

seek a pre-filing conference with the FERC staff.[36] Applicants can discuss, on an informal basis, the parameters of the case and the types of issues that may be of particular importance to the Commission. This is the only time that applicants will be able to engage in informal conversations with the FERC staff. Once the application is made, the FERC staff are prohibited from discussing the case privately with any interested party. All post-filing communication must take place in a public forum, either in publicly available written communication and documentation, or in a public gathering to which all interested parties are invited.[37]

The FERC relies heavily on third-party interventions to identify potential anticompetitive impacts of a merger. Parties opposing a merger are free to file their own analyses and opinions regarding anticompetitive effects. All information received from merging parties and intervenors collectively forms the public record in the case.[38]

Once the deadline for interventions has passed,[39] the FERC conducts an internal review of the merger. Staff can issue deficiency letters if additional data or information are needed. Once the application is complete, the Commission typically makes a ruling within four months or so. The Commission can: a) approve the merger; b) approve it with conditions that applicants must either accept or have the merger set for hearing; c) disapprove the merger; or d) set the merger, or a subset of issues in the merger, for hearing before an administrative law judge or in a less formalized process involving a "paper hearing" and/or technical conferences.

In recent years, the Commission has made a stalwart attempt to expedite the merger approval process. Mergers that involve no competitive issues can be approved within as little as four months. Because applicants are fully apprised of approval standards, merger applications are only rarely filed with unmitigated effects requiring a hearing. Mergers that present some issues generally are approved within six months. If a merger is set for hearing, the process can take a year or more. For example, the merger between American Electric Power and Central and Southwest, the first mega-merger involving large (albeit relatively distant) utilities, took more than two years.

B. The Department of Justice and the Federal Trade Commission

In addition to FERC review of mergers, the FTC (previously both the DOJ and FTC), under the various antitrust laws, applies additional scrutiny to electric mergers. Specifically, the HSR process requires a filing at the DOJ and the FTC of proposed significant mergers before the transac-

36. 18 C.F.R. § 35.6 (2002).

37. 18 C.F.R. § 385.2201 (2002).

38. Merging parties can request that certain information remain confidential. 18 C.F.R. § 388.112 (2002).

39. Depending on the notice period established by the FERC, third parties typically have forty-five to sixty days from the filing date of the application to file interventions at the Commission.

tion can be consummated.[40] The requirements of this filing are specified and are essentially the same for all mergers. The purpose of this pre-merger notification and review by the antitrust agencies is to allow effective remedies to be put into place before the transaction is completed. It is difficult and costly to challenge completed mergers in order to restore competitiveness to the market.[41]

There is a thirty-day waiting period (fifteen days in some cases) after a pre-merger notification is filed, during which time the FTC can perform pre-merger analyses.[42] The agency may require additional information not contained in the initial filing. In that case, the agency will ask for it in a "second request" to merging parties. This may be highly targeted or quite general (and perhaps burdensome) in nature. A second request will extend the waiting period another thirty days (ten days in some cases) beyond the date at which applicants have substantially complied with the initial request. On occasion, if the agency is not yet prepared to rule, it may ask an applicant voluntarily to withdraw and refile the application, thereby restarting the thirty-day clock.

Unlike the FERC process, the FTC staff review process takes place informally and behind closed doors. The review process involves continuous interaction between the agency and the merging parties. Third parties can make their concerns known, and the agencies have the power to require information from third parties. As with interventions at the FERC, these informal discussions with customers, suppliers, and competitors (and in the case of utilities, state agencies) are influential in determining whether the agencies will find that a merger or acquisition is problematic.

After the FTC staff completes its analysis, one of three recommendations will be made to the FTC:

- No further action (agency may still seek injunctive relief at a later time if it so desires);
- Injunctive relief (agency files suit in district court); or
- Proposed settlement (staff can negotiate a settlement with merging parties during the investigative stage—a settlement must by approved by the FTC).

One procedural difference between FERC and the FTC is that FERC sometimes will accept a behavioral restriction (*e.g.*, an enforceable code of conduct restricting relations between vertically linked entities), whereas the agencies virtually always have demanded a structural solution to competitive problems (*e.g.*, divestiture). However, this is only a nuance; the

40. Hart-Scott-Rodino Act, 15 U.S.C. § 18 (2001).

41. For a complete description of the merger review process of the antitrust agencies, see PRE-MERGER NOTIFICATION OFFICE, BUREAU OF COMPETITION, TRADE COMM'N, *Introductory Guide I to the Pre-merger Notification Program* (Jan. 2002) (revised), *available at* http://www.ftc.gov/bc/hsr/introguides/guide1.pdf.

42. As mentioned, the current *ad hoc* sharing process between DOJ and FTC has been replaced by a permanent agreement that gives energy mergers to the FTC. *See generally Memorandum of Agreement*, *supra* note 2.

FERC also takes a structural view of mitigating horizontal market concentration arising from mergers, and typically requires structural remedies.

IV. MERGER ANALYSIS

A. *The FERC's Current Approach*

As mentioned, the FERC currently reviews electricity mergers using a delivered price test. Applicants are required to supply an analysis using this test as part of their application. The test is fully specified in the Commission's *Merger Policy Statement*, Order No. 592, issued in December 1996, as incorporated into section 33.3 of the Commission's regulations.[43] Appendix A to that order is a recipe for performing the analysis. Subsequent case law and policy orders have provided further guidance but have not materially modified the delivered price test.

The delivered price test is used to define the relevant geographic market, measure the concentration of supply in that market, and determine the effects of a transaction on concentration. This approach is grounded in the DOJ/FTC *Horizontal Merger Guidelines*. One difference is that the definition of the relevant geographic market generally is pre-specified rather than being a subject for investigation.[44] The market definition begins with a central destination market, typically a control area operated by a public utility. By itself, this can be a large area encompassing the generation assets not only of the control area operator, but also those of smaller embedded entities, such as municipal utilities or power cooperatives. The destination market is one of several control areas that are interconnected by a transmission grid with many branches and parallel paths, with limits placed on the amount of power that can be transferred between and among the control areas. Such power transfers are charged a transmission rate for each leg of the journey, called "wheels."

A supplier can be considered part of the relevant geographic market if it is able to deliver power to the destination market at less than 105% of the prevailing price. For suppliers that are internal to the destination market, this requires that the variable cost of their generation production be less than this target amount. An assessment of variable cost is made for each generating unit owned by internal suppliers. All suppliers that are economical are considered to be part of the relevant geographic market. External suppliers that can deliver power at a price less than the destination market target price, including any applicable transmission rates, are candidates for inclusion in the relevant geographic market in the sense that their supply is economic. The total of external supplies, however, cannot exceed the amount that can be imported into the destination market con-

43. *Merger Policy Statement*, *supra* note 7; Order No. 642, *supra* note 35.

44. There are exceptions to this rule and some applicants have successfully argued for non-standard definitions of relevant geographic markets. However, using a non-standard market definition seriously increases the risk that the merger will be set for hearing, so most applicants simply accept the standard FERC definition.

sidering the limits to the transmission system.

Importantly, under FERC practice, all economical external power is considered to contend for delivery to the destination market. For example, if South Carolina Electric & Gas is the destination market and the target price is $25 per MWh, all economical power in a multi-state area (perhaps as large as the area encompassing Pennsylvania, Illinois, Louisiana, and Florida) would vie for delivery over limited transmission facilities. This aspect of the FERC analysis ensures that transmission imports into the destination market will be constrained (*i.e.*, the transmission pipes will be "filled up") in the market analysis, regardless of whether such constraints are ever reached in reality. This abundance of external power necessarily must be rationed over the limited transmission capacity. Typically, this is done by some type of pro-rata allocation. The FERC's market definition process ensures that all economical internal suppliers are included in the market definition, but that only a portion of all economical external suppliers are included as well. More distant suppliers that pay multiple wheeling charges can qualify only with generation that, inclusive of wheeling charges, still comes under the destination price bogey. While this provides some limit on distant supply, it is generally the case that at least some of the lowest cost supply of distant utilities (the analysis generally is cut off beyond three wheels, although this is an arbitrary limit) will be included in the market definition.[45]

The delivered price test is used to define the relevant geographic market for various time periods reflecting seasonal and time-of-day supply variations. It is typical to use nine to twelve time periods for three seasons (summer, winter and shoulder) and three to five intra-day periods (superpeak, peak and off-peak). The periods are defined to reflect potentially different economic conditions, such as planned maintenance of generating units occurring in shoulder periods and high prices occurring in summer peak periods. The number of such periods studied reflects a concern that market structure may differ by season (*e.g.*, because of the seasonality of hydroelectric output) or by load level (*i.e.*, because only low variable cost capacity competes in low-load periods).

The relevant products studied in the FERC delivered price test are energy and short-term capacity. Energy is an hourly, non-firm product that is sold on a very short-term basis. Short-term capacity can be defined as weekly, monthly or annual capacity. In practice, the short-term capacity market is quite similar to an energy market at the time of highest load and prices, when all capacity would be used to produce energy.[46] Reflecting the

45. A more significant limit on distant power is that proration occurs at each node of the system. Consider a 1,000 MW supplier located in a control area with 20,000 MW of power that would be delivered economically to the destination market. If there is only 2,000 MW of transmission capacity connecting that control area to an adjacent control area that lies between it and the destination market, only 10% of the power reaches the intermediate market. If the facts about the intermediate market are similar (*i.e.*, only 10% of economic capacity can flow to the destination market), then all that remains of the 1,000 MW is 10% of 10%, or 10 MW.

46. Note, however, that such an analysis would not account for operating reserves, which typi-

transition from monopoly service to retail competition, the market and shares within it are measured using two concepts called "Economic Capacity" and "Available Economic Capacity". A supplier's Economic Capacity consists of its owned resources, adjusted for long-term wholesale purchases and sales (other than requirement contracts) that transfer control over the generation among parties and that have variable costs at or below the level required to meet the delivered price test. Available Economic Capacity is a supplier's Economic Capacity reduced by an amount reflecting its native load commitments, such as state-regulated retail load obligations and FERC-regulated wholesale requirement contracts. In concept, Available Economic Capacity is the amount of capacity available to the supplier to sell at wholesale today, while Economic Capacity is the amount that it would have available to sell at wholesale under full retail access.

In summary, the FERC merger screening analysis would consist of a delivered price test conducted for all relevant destination markets (reflecting an overlap of the two merging companies), for nine to twelve time periods, and two product measures. Typically, several hundred model runs are required to comply with the filing requirements.

The data and technical requirements of such an analysis are formidable. The effort requires data on each generating unit over a wide geographic area, a relatively detailed depiction of the transmission system, and all relevant load data. Such data must be updated fairly frequently as a result of new entry and changes in transmission contracts. The analysis itself requires a computer model built for the specific purpose of such analyses, the core of which is a linear program. If the transaction is likely to change transmission flows, a power flow simulation may be necessary to measure the impact of the transaction on the transmission system. The FERC requires that models and databases be made available to intervenor experts and Commission staff for use in performing their own analyses.

B. Issues

A number of issues arise in the implementation of the FERC's delivered price test. These are discussed below.

1. Lack of Opportunity Costs

In concept, competitors in the market for electric power are those who would respond to a small but significant price increase. However, they are unlikely to do so if they have better alternatives elsewhere, even with the elevation in price. The delivered price test has been criticized for not addressing a competing generator's opportunity cost of selling power into the destination market under the FERC test.[47] Any external generator considering such a sale would also consider its alternatives, including the obvious choice of selling within the control area where it is located or

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cally would require that generation capacity equal to about 6% of peak load be "standing by."

47. Mark W. Frankena, FERC's Merger Policy: Reflections on Appendix A, Presentation to Energy Bar Association, Mid-Year Meeting, Washington, D.C. (Nov. 20, 1997) (on file with authors).

in some other direction where wholesale prices are higher. The decision on where to sell depends critically on the prices in the destination market relative to those elsewhere. By ignoring such opportunities, the FERC test potentially makes two mistakes. First, it is possible that some suppliers included within the geographic market would not be available in reality because of more attractive markets elsewhere. If so, the market may be smaller than indicated by the test.

Second, it also is possible that transmission would not be constrained in reality because adjacent markets are clearing at the same price. If so, the market may be larger than indicated by the test because the transmission constraints would not be binding. Consider the example of the Desert Southwest and California. There are very substantial transmission links between the two areas. For most of the year, prices in California are higher and power flows from east to west. It could be objected that if a generator in Arizona sought to raise the Arizona price by 5% or 10%, California suppliers would not respond since the price there still would be higher.[48] However, it generally will be the case that Arizona prices are net-back from California, reflecting transmission rates and losses. Under these circumstances, Arizona is not truly a market. Withholding capacity in Arizona would raise prices in both Arizona and California, by quite similar amounts, and California suppliers unquestionably would respond to a price increase caused by the actions of an Arizona generator.[49]

The obvious answer to both of the above criticisms would be to develop a delivered price test that accounts for interconnectedness of markets and opportunity costs. But this would not be a trivial extension of the test. It would involve the calculation of a multi-area energy trading equilibrium and a determination of which suppliers respond to hypothetical increases in market-clearing prices in destination markets in order to assess which suppliers to include in the relevant geographic market.[50] Our experience with such models suggests that the identification of these suppliers can be uncertain and results highly unstable. Models used for this purpose recompute the multi-area trading equilibrium when inputs are changed so as to increase the price in a particular area. The new equilibrium may or may not be useful in assessing which suppliers would respond to such a hypothetical price increase because it may reflect a substantially different geographical supply pattern than in the base case. This can hap-

48. More accurately, the net-back revenues would be too low to justify shifting from sales in California to Arizona. If transmission losses and charges are 5% between the two areas, and transmission is unconstrained, then the price difference would be 5%, with California higher. Raising the price in Arizona by 5% still would not cause the California generator to sell to Arizona, since it would incur 5% transmission cost to do so.

49. Exports from Arizona to California would be reduced by the withholding in Arizona, which would elicit a response from California suppliers as replacements. The new net-back equilibrium would involve greater supply from rivals within the Arizona control area and from rivals within California.

50. This is a literal implementation of the *Guidelines* method for defining markets to encompass those suppliers who would respond to a small but significant price increase.

pen because the model minimizes multi-area production costs, the solution to which is sensitive to small perturbations in the inputs. Reducing the supply in area A in order to increase the price in area A, for example, may cause some external suppliers to increase their output (as expected) and others to decrease their output (a counterintuitive result). This may reflect a new set of binding transmission constraints, or it simply may be an improved solution, but one that saves only a *de minimis* amount of production costs while involving large shifts in power production between and among the interconnected areas. Such a result can be difficult to capture in structural measures.[51]

We have some experience with such analyses. Typically, we have found that the supply response to withholding capacity is scattered over a very wide area. This is not because generation in, say, Kansas increases to serve load directly in Indiana that is affected by the withdrawal of Indiana generation. Rather, Kansas generation increases to replace Missouri generation that is used to supply load in Illinois that partly was served by generation that now is exported to Indiana.

Moreover, who responds to a withdrawal of capacity is highly dependent on specific circumstances, such as which units are fully loaded and cannot respond (or for short-run analyses are off-line and cannot respond), the status of the transmission system in terms of constraints, and the detail of how changing the loading of one unit affects other flows. In short, no single analysis will provide a complete picture of what generators, or what geographic areas are "in the market" and constrain the behavior of an applicant.[52]

Whatever the virtues of seeking to better specify competing capacity for merger analysis, and in principle they are substantial, it is clear that any serious attempt to do so would result in analysis requirements that are an order of magnitude more complex than the already-complex requirements of a delivered price test. Moreover, the interpretation of results necessarily would involve art and judgment rather than mechanical rules. This eliminates the possibility of improving a screening analysis to incorporate

51. While the suppliers with a positive response should be included in the relevant market, the treatment of the suppliers with a negative response is not so clear. For example, suppose the model reduces an external supplier's capacity from 1,000 MW to 900 MW in response to some distant hypothesized withholding strategy. If only incremental capacity were counted, this supplier would have a negative 100 MW in the relevant market, which would be nonsense, of course. On the other hand, one might argue that all of the capacity of any responding supplier (positive or negative respondents) should be included, in which case, this supplier's 900 MW would be included in the relevant market. This might be appropriate if the supplier's negative response is important in providing the means to relieve an intervening transmission constraint so that some other supplier can make deliveries. But, it might be a spurious rearrangement of supply patterns that has been found by the model where the small cost savings are not likely to reflect any likely market response. Accordingly, some judgment may be needed, which would detract from the usefulness of an opportunity cost model as a screen in market reviews.

52. Of course, difficulty in specifying bright-line definitions of geographic and product markets is not restricted to electricity; it merely is made more apparent by the ability to model the industry so fully.

these effects. However, we note that the modeling requirements for this type of analysis are essentially those required for a behavioral analysis and revisit these issues in that context.

2. Economic Capacity versus Available Economic Capacity

The Available Economic Capacity (AEC) measure is constructed by subtracting native load obligations, such as state-regulated retail service or wholesale requirements contracts regulated by the FERC, from Economic Capacity (EC). AEC is related to the concept of uncommitted capacity, which can be used as a measure of short-term capacity available for sale in the wholesale market. The idea has been that capacity in excess of native load obligations could be sold in the wholesale market for periods of one year or less, but would not likely be available for longer-term sales.[53] In contrast, EC measures a utility's total presence in the market, which may be adjusted in hourly spot markets depending on the wholesale price. Thus, EC has been considered primarily a measure of energy (hourly, non-firm energy, in particular).

Several issues arise with this dichotomy. First, as retail markets are deregulated, it becomes increasingly more difficult to identify native load obligations. Second, merger analysis is forward-looking. For areas transitioning to retail access, the dedication of capacity to native load is only transitory. The FERC has recognized this and tends to place less reliance on the AEC measure in markets where significant retail deregulation is occurring.[54]

Because of its historic relationship to uncommitted capacity, the AEC sometimes is thought of as a valid measure of markets for capacity as a product distinct from energy. However, the distinction between EC and AEC does not actually reflect energy versus short-term capacity. For example, generation running costs are not necessarily indicative of the opportunity cost of a capacity product. Instead, the distinction is driven by a need to capture the somewhat uncertain effects of state retail regulation on behavior in wholesale markets. Under FERC guidance, long-term wholesale contracts have the effect of transferring the control of capacity from the owner of the capacity to the wholesale buyer of the power produced by that capacity. This means that contracts regulated by the FERC have the effect of transferring market share from a wholesale supplier to a wholesale buyer partly based on the theory that energy sold to another party will not benefit from increasing prices, and cannot be used to increase prices. Retail service regulated by state commissions on a cost basis similarly removes capacity from participation in the competitive market. At the not-uncommon extreme, a utility that must buy in the short-term market to meet its retail load requirements at fixed prices is manifestly not interested in withholding its generation capacity in order to increase wholesale prices.

53. Because the AEC does not account for operating reserves, it is sometimes used as a measure of the energy product.

54. *EME Homer City Generation, L.P.*, 86 F.E.R.C. ¶ 61,016 (1999).

Nonetheless, the fact that the FERC transfers commercial contracts away from a supplier but deals with native load through the EC/AEC distinction suggests that the FERC does not regard native load as equivalently reducing the incentive to increase prices.[55] To account for the price discipline that is nonetheless imposed indirectly on wholesale markets through state regulation, the EC versus AEC distinction provides an indication of a utility's market position both in total and in relation to regulated responsibilities. While this distinction has validity in traditional wholesale markets that are dominated by regulated retail needs (where wholesale markets are effectively secondary markets in hand-me-down power not needed for retail load), it will become obsolete as retail deregulation expands and matures. However, the industry and its regulators are less optimistic than they were a few years ago concerning how rapidly this transition will be completed.

3. Ability versus Incentive

The exercise of market power is generally considered to require both the ability and incentive to raise market prices by a significant amount for a sustained period of time.[56] That is, any price increase that could be induced by a supplier would need to be profitable in order to provide an incentive to engage in the action in the first instance.

In the electricity industry, a supplier that controls the availability and dispatch of a generating unit potentially would have the ability to withhold the unit's capacity from the market and thereby influence market prices. The incentive to engage in such behavior would reside in the entity with the beneficial interest in the unit's profits. When the same entity controls the unit and also benefits from its production, it is clear that the unit should be included in that entity's market share.

When the ability and incentive are separated, however, matters are not so clear. Further, such separation is commonplace in this industry. Examples include jointly owned plants, tolling agreements, and long-term contracts that remove short-term incentives through contractual pricing not based on spot prices.[57] Under FERC practice, the generation capacity

55. This uncertainty surrounding which structural measure to use may reflect the view that a utility might seek to raise prices in wholesale markets even if the fruits of its efforts flow to ratepayers rather than shareholders. If so, behavioral modeling of the firm's profit maximizing strategy also would not be able to accurately represent the incentive to raise prices because the alleged ratepayer benefit would not be included.

56. This definition is based on the DOJ/FTC *Horizontal Merger Guidelines, supra* note 7. In contrast, see FERC Staff Strawman, *supra* note 21, defining market power simply as the ability to raise market price above the competitive level. This would appear to conflict with the *Guidelines*, which discusses both incentive and ability, and refers to a "small but significant and nontransitory increase in price." *Horizontal Merger Guidelines, supra* note 7. However, this distinction may be of little practical consequence. The FERC Staff Strawman goes on to suggest that Commission intervention is needed when market power is significant and sustained, and that unprofitable actions are unlikely to be sustained.

57. Non-dispatchable units, such as nuclear units, may also be appropriately considered as providing incentive but not the ability to exercise market power, depending upon the market rules.

associated with such long-term contracts is attributed to the wholesale buyer of the power. This attribution may be reasonable for some contracts but not others. If the contract effectively allows the buyer to control the unit's production (both its availability and dispatch) in exchange for a contractual price not based on spot prices, then the buyer would have both the ability and incentive to potentially raise spot market prices, and it is reasonable to conclude that the unit's capacity should be reported in the buyer's market share, not the owner's, in calculating structural measures of market power.

Many contracts, however, transfer either the ability or the incentive, but not both. When this is the case, the entity to which the capacity should be attributed is not clear. In some instances, it is possible that the correct answer would be that the capacity should not be attributed to either the seller or the buyer, but rather simply omitted from the market. The rationale for such a conclusion would be that no single entity controls both the ability and the incentive associated with a unit, so the unit should be omitted from the market altogether, *i.e.*, it should not be included in the numerator of any market share calculation (the capacity of a particular supplier) and it should not be included in the denominator (total market size). Alternatively, it could be included in the denominator on the grounds that the decoupling of incentive and ability effectively makes it a price taker. In practice, it is difficult to assess such matters without detailed knowledge of the underlying contracts. The practical solution here is to attribute the capacity to the entity controlling the operation of the plant (*i.e.*, the entity with the ability to withhold capacity) in the screening analysis, and revisit the issue as appropriate if additional review is needed.[58] The FERC staff seems to be moving toward this view.

The FERC roughly follows this rationale in addressing generation used to serve native load when it assesses the AEC measure. In this case, a retail regulatory obligation removes the incentive to exercise market power because the generation cannot benefit from higher prices, but the regulated utility retains the ability to withhold the capacity. Given this split, the EC measure effectively assesses markets as if the regulated utility has both the incentive and ability, while the AEC measure removes capacity obligated to native load from the market altogether. The schizophrenia is handled by making both calculations, which is a reasonable way to pro-

58. Note that some contracts transfer the dispatch of a unit to the buyer, but not the maintenance responsibility. Such contracts separate the ability dimension into availability and dispatch and transfer only a portion of ability. Other contracts give the buyer the option to dispatch a plant, but the owner reserves the dispatch right when the buyer chooses not to exercise it. This is an options contract that separates ability and incentive on the occasions when the buyer exercises the option, but not otherwise. In a prospective market study, the buyer would exercise the option when the plant is economical, and so the owner would not have the opportunity to withhold the capacity at any time when such an action could drive up prices. Consequently, incentive and ability are separated in such an options contract and the capacity should not be attributed to the owner, even though the buyer sometimes does not exercise its option. In the real world, it is possible that non-economic factors would cause a buyer to not exercise the option at times when the unit is economical, and then it could be withheld to gain an advantage for the owner. However, such circumstances cannot be modeled in a prospective analysis.

ceed within the context of structural measures.

It is significant that this uncertainty about the proper treatment of power purchase contracts in a structural analysis is not a concern in a behavioral analysis. A behavioral analysis would simulate each supplier's behavior regarding the availability and dispatch of the units it controls and would determine a market-clearing price by equating aggregate supply and demand. In such an analysis, it is possible to model ability and incentive separately. Ability is directly modeled by specifying which units an owner could hypothetical withhold or bid at an asking price higher than marginal costs. Incentive is directly modeled by determining the quasi-profits (revenue in excess of marginal cost) of each owner. This profit calculation can account for contracts directly. For example, a contract to sell power at a fixed contractual price would not be included in any spot market profits resulting from a withholding strategy. The accounting for this could be done in several ways. For example, the contract could be modeled as a contract for differences in which the generator is first paid the spot market price, but then must settle with the buyer at a price equal to the difference between the spot price and the contract price. In this way, the generator could be considered to be in the spot market for the purposes of determining the market-clearing price, but it would not benefit from higher spot prices induced through its strategic behavior.

Behavioral modeling substantially increases the flexibility of representing different types of contractual, and even regulatory, obligations. Regulated native load obligations, for example, could be modeled in a contract-for-difference framework that would allow the capacity to be used to increase prices through hypothesized strategies, but would remove the incentive to do so, as reflected in the obligation to sell to native load at a regulated price. While this flexibility to represent ability and incentive separately in the analysis is a substantial advantage of behavioral modeling, it must be weighed against some drawbacks discussed later.

4. Appropriate Time Period

Electricity consumed in one time period cannot, in most applications, be substituted for consumption in another. Similarly, (with the exception of energy-limited units, primarily hydroelectric generation) production cannot be substituted between one hour and another. Nor can electricity be stored in non-trivial amounts. For these reasons, electricity produced at different times constitutes different "products" in the sense that the term is used in antitrust.

While it may be true in some formal sense that electricity is a separate product in each hour, indeed each moment, it would be pointless (as well as expensive and tedious) to analyze each hour separately. The issue of what periods to analyze involves two questions. The first is factual: how many groupings of hours, or representative hours, are needed to represent reasonably the range of market conditions? As noted earlier, the methodology currently used by the FERC uses representative hours arrayed by season and load levels within a typical day. The second question relates to the sustainability of market power. The corner convenience store may have market power during a blizzard, but we do not evaluate mergers among such firms on the assumption that a blizzard is occurring. A key lesson from comparing the California experience to the price spike events discussed previously in this paper is that the public is injured primarily by prolonged market dysfunction.

The recent FERC Staff Strawman suggests that the appropriate period of time for a market study is probably measured as a matter of a few months, and not hours or a year.[59] The conventional wisdom is that times of scarcity may provide a greater opportunity for suppliers to engage in strategic behavior. Accordingly, it is likely that market power problems would occur during summer peak periods rather than during the spring and fall, when demand is down. This is not certain, however, because planned maintenance of generating units during the spring and fall off-peak seasons occasionally can reduce supply significantly, especially if a large unit or two experience unexpected outages.

An advantage of studying a whole season would be the recognition that most mid-cycle generating plants have certain operational inflexibilities, such as minimum running times, minimum output levels, and start-up time and costs, that prevent them from engaging in certain strategic behavior. An example would be that a unit with a shut-down and start-up cycle of sixteen hours cannot be effectively withheld for a portion of a day. Such a unit could produce its minimum output during the daily peak period (*i.e.*, withhold the output above its minimum production level) and then provide off-peak production on a competitive basis. However, such a change in strategy during the course of a single day would produce anomalous output patterns that would be easy for a regulator or market monitor to detect. Such a unit is likely to produce more during over-night hours than during the peak afternoon period—a pattern likely to invite questions from market monitors. On the other hand, it would be difficult to develop good structural measures for an average summer-long time period. Such a period would mask important price differences between over-night and afternoon hours. A behavioral model may be better suited to address both operational inflexibility and diurnal price swings, in that seasonal strategies could be studied using a model that accounts for such price patterns.

5. Geographic Market Definition

In a structural analysis, relevant geographic markets should be defined to include suppliers that could respond to a hypothetical "small but significant"[60] increase in the market price in accordance with the DOJ/FTC

59. FERC Staff Strawman, *supra* note 22, at 3.

60. What counts as "significant" to some degree is a matter of taste. The *Guidelines* suggest a 5 to 10% increase. *Horizontal Merger Guidelines*, *supra* note 7. However, it would be poor public policy to reject a merger on the grounds that the post-merger firm might be able to increase prices by 5% for a short period of time under transient conditions. Moreover, for reasons beyond the scope of this paper, the long run marginal cost that must be recouped by new entrants is above the narrowly-defined

Guidelines. The FERC methodology for doing this has two parts: internal and external. The internal suppliers effectively are pre-specified as being in the market by the selection of a control area as the destination market. While exceptions to this increasingly are allowed,[61] the use of a control area in this manner avoids the need to answer most of the important questions that often are critical in antitrust analysis. The external suppliers, on the other hand, are identified in the FERC analysis as a function of transmission limits and delivered costs, in much the manner as an antitrust analysis.

Several practical questions arise in implementing the FERC's adaptation of the *Guidelines* for electricity markets. The hypothetical competing supply from outside the control area would be delivered over transmission with limited capacity. While there may be very many suppliers who could use this capacity to respond to increased prices, their collective ability to do so is limited by the available transmission. Moreover, transmission capacity that they could use must be measured relative to that which is available taking into account the base-case flows occurring before the hypothetical price increase. Two approaches are possible within the context of currently available data. One would measure Available Transmission Capacity (ATC) above the base-case flows (deducting also the transmission that has been allocated or purchased on a long run basis), while the second would use Total Transmission Capacity (TTC), which would be based on feasible power flows in the absence of reserved uses.

Irrespective of which measure is used, the base power flow itself reflects uses of interface capacity that reduce the capability of external generators to compete. The base power flow reflects specific (but generally non-transparent) assumptions about the pattern of generation. TTC is the capacity remaining after the effects of the base flow are taken into account.[62] Moreover, the amount of additional power that could flow is unlikely to equal the TTC. When transmission is reserved, the engineers at the transmission-controlling entity reduce availability to reflect the reservation. When a particular transaction is modeled by power flow engineers, it changes the flow on all parallel lines in the grid that support the power transfer. Different reservations will have different effects. A mar-

short run variable cost that often is used as a measure of competitive prices. For this reason, an additional source of revenue (in the form of "scarcity rents" of energy or payment for some other product, such as installed capacity) is needed. To the extent that small elevations in energy prices merely substitute for this other source of revenue, they are likely to be benign.

61. For example, the standard way of analyzing the PJM, New York, California and New England markets is to recognize transmission interface constraints that are not coincident with utility boundaries. These are constraints that actually bind with substantial frequency, as opposed to the interfaces around a control area that may, or may not, bind in reality. Notably, each of these areas has an ISO that monitors and reports on such transmission interfaces.

62. Apart from base-case power flows, the TTC is also adjusted by each control area operator for Transmission Reliability Margin and Capacity Benefit Margin. The magnitudes of these adjustments are not fully transparent, adding to the modeling complications. Moreover, the transmission capacity set aside under either of these margins sometimes can be used to deliver non-firm energy, thereby potentially providing an additional check on market power.

ket study is performed by economists who generally will not be able to replicate the set of transactions incorporated into the power flow analyses performed by the power engineers of a hundred different utilities.[63]

The economist, then, has two choices: try to replicate the base-case transaction set and use ATC as the measure of transmission limits, or ignore the base-case transactions and use TTC. As a practical matter, using TTC tends to provide a better basis for the analysis because of possible errors in attempting to replicate the base transactions. If this approach is used, it is nonetheless important to account for jointly owned plants that are used to deliver power to multiple control areas. This can be done by "moving" a portion of a jointly owned plant to the control area of the particular joint owner in question and then subtracting the transferred generation from the corresponding TTC. This is an admittedly practical solution to a complex measurement problem. In the future, better and more consistent ATC measurement along with transparent data on base-case power transfers should be able to replace this practical approach.

A second issue that complicates the definition of the geographic market is load pockets. A load pocket is an area of the grid that has more demand than transmission import capacity. A load pocket must have at least some internal generation running to support internal demand. In some cases, the load pocket is small and has only a few internal generators. If these generators are owned by a single utility, or by only a few utilities, the load pocket may be susceptible to the exercise of market power, especially during peak times when demand exceeds the import capacity. A load pocket can become an issue in defining the market when it is smaller than a control area, which is otherwise the smallest geographic area represented in a market analysis. Over time, the FERC and its practitioners have recognized that load pockets exist in many control areas, primarily in large urban areas such as Boston, New York, San Francisco, Chicago, New Orleans, and Florida. An analysis of such areas is becoming increasingly important. For example, the area in the southwest of Connecticut is a load pocket. When NRG Energy proposed to buy two generating plants from Wisvest (a subsidiary of the holding company owning Wisconsin Electric Power Co.), the transaction was questioned by the FERC because, as was alleged by an intervenor, it would have combined the capacity with other capacity owned by NRG Energy in the load pocket.[64] The load pocket was not studied initially because it does not have its own market-clearing price, but rather its price is based on a market price determined for the New England area as a whole.[65] This argument did not persuade the FERC, which was interested in possible future developments in locational pricing that could support separate prices for this load pocket. As a result of de-

63. It also should be noted that the ATCs and TTCs posted by different transmission operators for the same interfaces often differ.

64. Order Establishing Further Procedures on Proposed Divestiture Transaction and Market-based Rates, *Wisvest-Connecticut, LLC,* 96 F.E.R.C. ¶ 61,101 (2001).

65. The New England ISO has not yet introduced locational marginal pricing, but appears to be on a course that will do so within a few years.

lays created by the FERC inquiry, as well as that of the antitrust agencies, NRG Energy abandoned its proposed acquisition prior to any finding by the FERC or the DOJ. It is clear that load pockets cannot be ignored in market analysis, even in advance of the time when they have separate prices.

A third issue that must be addressed in defining geographic markets is transmission rates. A transmission rate is charged to move power between control areas now and, in the future, between RTOs, which will become groupings of control areas under the FERC's policy initiative. A transmission rate theoretically can cause a price difference between adjoining control areas (or RTOs). This could happen if the difference in market-clearing prices between the two areas were less than the prevailing transmission rate. So, if the transmission rate were $5 per MWh, and the two prices differed by only $3 per MWh, traders could not profit by moving power between the two markets. In a market study, it is commonplace to impose fixed transmission charges on power movements between control areas (or RTOs). In reality, transmission rates can be discounted by transmission owners in order to gain additional throughput and its attendant revenue. This discounting is not easily incorporated into a market study because it is often non-systematic; however, this limitation is not important in practice. We have found that the most important factor in defining geographic markets is transmission limits and that transmission rates do not influence geographic market definition significantly. In particular, transmission rates have almost no impact on market definition under the FERC's delivered price test and do not appear to be otherwise significant, for example if an opportunity cost modeling approach were used.[66]

Each of these issues—transmission limits, load pockets, and transmission rates—also must be addressed if behavioral modeling is used instead of structural analysis. The location of suppliers responding to hypothetical strategies in a behavioral study would correspond to the geographic extent of the market in a structural study.

C. *Possible Alternative Approach—Behavioral Modeling*

To move beyond the FERC's delivered price test is likely to require going beyond structural analysis into the area of behavioral modeling. As mentioned, behavioral analysis is a prospective study of hypothetical strategic behavior, *e.g.*, withholding of power from particular generating units, that is conducted using direct simulation techniques.[67]

66. In an opportunity cost model, a reduction in transmission rates, perhaps achieved by forming an RTO and thereby eliminating transmission charges within a larger area, can have either of two effects. It may equalize prices over a larger area, in which case the geographic market would be larger. Or, it also may encourage more trading and thereby cause transmission constraints to bind that theretofore were slack. This can reduce the geographic size of the market. In our experience with experimenting with such models, both effects occur with about the same frequency, so a reduction in transmission rates has little practical importance in expanding the scope of a properly defined market.

67. Market power modeling ranges from price leadership models to Cournot models. For a basic description of the price leadership model, see JEAN TIROLE, THE THEORY OF INDUSTRIAL

Such models could be used to simulate prices before and after a merger to assess its competitive impact. One way to do this would be to compare the Cournot equilibrium price before and after the merger.[68] Another way would be to determine the price increase that would result if one of the merging firms is acting as a dominant firm before the merger and the merged firm continues its domination following the merger. This calculation can be done using each of the firms as the pre-merger dominant firm and using the greater of the two resulting comparisons. Under either the Cournot or dominant firm approach, the metric is the profitable price increase associated with the merger, in contrast to the increase in the HHIs in a structural analysis.[69]

The advantages of a behavioral approach are numerous.[70] As mentioned, the flexibility of a behavioral simulation allows the ability and incentive to exercise market power to be addressed separately. This can eliminate the uncertainty and confusion regarding the attribution of generation when ability and incentive are separated. In addition, behavioral modeling can be used to address detailed issues, such as hour-by-hour behavior and price increases that then can be averaged in an appropriate way to derive an average measure of the market power problem. The technique also can address opportunity costs including both geographical opportunities accounting for transmission constraints and temporal opportunities accounting for energy-limited resources, such as annual water limits for hydro resources or annual pollution limits for thermal resources.

The disadvantages of behavioral modeling, however, are also numerous.[71] First among these is the lack of a screening criterion. While screening standards exist for changes in HHIs for the structural analysis of mergers, no similar standards are available to assess a level of price increase due to a merger that would be small enough so as not to require additional re-

ORGANIZATION (Mass. Inst. Tech. Press 1988). A variation of the Cournot model using Nash equilibrium concepts is used in Catherine D. Wolfram, *Measuring Duopoly Power in the British Electricity Spot Market*, 89 AM. ECON. R. 805 (1999). *See also* Paul D. Klemperer & Margaret A. Meyer, *Supply Function Equilibria in Oligopoly under Uncertainty*, 57 ECONOMETRICA 1243 (1989).

68. In a Cournot equilibrium, each supplier has some ability to influence the market price and believes that the quantity produced by other Cournot players (his rivals) remains fixed. This behavioral assumption produces an equilibrium price between the competitive and monopoly levels. F.M. SCHERER & DAVID ROSS, INDUSTRIAL MARKET STRUCTURE AND ECONOMIC PERFORMANCE 200 (3d ed. 1990).

69. For examples of behavioral modeling of market power in electricity markets, see Tabors Caramanis & Associates, *Horizontal Market Power in Wisconsin Electricity Markets: Report to the Public Service Commission of Wisconsin* (Nov. 2, 2000), *available at* http://psc.wi.gov/electric/cases/mktstudy/documt/mktstudy.pdf; James Bushnell & Celeste Saravia, *An Empirical Assessment of the Competitiveness of the New England Electricity Market*, Report to the ISO-NE, (Feb. 2002), *available at* http://www.iso-ne.com/iso_news/An_Empirical_Assessment_of_the_Competitiveness_ of_the_NE_ Electricity_Market.pdf ; B.F. Hobbs et. al., Strategic Gaming Analysis for Electric Power Networks: An MPEC Approach, Presented to the IEEE Power Engineering Society 1999 Winter Meetings, New York, N.Y. (Feb. 4, 1999) (on file with author).

70. WISCONSIN ELEC. POWER CO. & PUTNAM, HAYES & BARTLETT, INC., Joint Comments on the Use of Computer Models in Merger Analysis, F.E.R.C. Docket No. PL98-6-000 (June 15, 1998).

71. *Id.* at 7-8.

view.[72] In the absence of such a standard, behavioral modeling is likely to result in virtually all mergers being subjected to additional review. This is because behavioral modeling can almost always show that a finite-sized supplier has some small degree of market power at some times. Without any limits on the time period to be assessed or on the magnitude of non-reviewable price increases, behavioral modeling will call out even very small acquisitions for detailed scrutiny. This would result in an ineffective screening process that would produce many false positive indications of market power that would not exist in reality. By itself, this is a fatal flaw in using behavioral analysis as an initial screen, or in any regulatory requirement to engage in such modeling. It would not be appropriate for a regulatory agency to require a behavior modeling approach without indicating how such information would be used in its assessment. In the absence of screening criteria, then, the remaining role for behavioral analysis would be its potential use in the additional review process. For example, a merger application might fail a structural screen, thereby indicating a need for additional review. The applicant could have the option of submitting behavioral analysis as part of its application. A purpose of such analysis might be to indicate why the structural screening failure is not a concern, perhaps because the incentive to exercise market power is absent or insignificant. Used in this way, the behavioral analysis can serve as supplemental evidence. Likewise, regulatory agencies may have an overall interest in using behavioral analysis in assessing market conditions as a general matter and outside of the merger review process. These other uses of behavioral analysis could provide an important understanding of electricity markets, but it is unlikely that behavioral analysis could become the primary method used to assess the competitive implications of mergers without the development of screening criteria.

V. MARKET-BASED PRICING OF WHOLESALE ELECTRICITY

The FERC has the authority to allow a jurisdictional public utility to sell power at wholesale at market-based rates.[73] In practice, the screen used since the first market-based rate approvals in 1989 until November of 2001 resulted in market-based rate authority being granted to virtually every wholesale seller of electricity that has requested it.[74] This was by de-

72. The DOJ/FTC *Guidelines* refer to a 5% price increase as part of the hypothetical process used to define the relevant geographic market, but this has not been directly used as a screening standard in behavioral analyses. *Horizontal Merger Guidelines*, *supra* note 7. Apparently, the agencies are concerned that acceptance of a price increase as a screening threshold in a prospective market analysis might create the appearance of accepting similar price increases in enforcement matters. The agencies have been clear that there is no tolerance of any level of price increase in the enforcement of antitrust violations.

73. Farmers Union Centr. Exch. v. FERC, 734 F.2d 1486 (D.C. Cir. 1984). For a good overview of market power in the electricity industry, see Gregory J. Werden, *Identifying Market Power in Electric Generation*, PUB. UTIL. FORT., Feb. 15, 1996, at 16.

74. There are some exceptions. Generally, these are utilities that have foregone market rate authority to make wholesale sales at market rates to customers within their own service areas. Foregoing

sign. The FERC used this applicant-by-applicant approval process to transition gradually to competition. There are currently over 1,200 entities authorized to sell energy at market-based rates.[75]

The large number of entities with market rate authorization demonstrates an important constraint on a commission-specified market power test for market rate authority. The test must be simple if all of these applicants are required to file it and the FERC staff must review each application. The sheer volume of applications necessitates a simplification relative to what the Commission can require in the case of a merger, for example.[76]

To obtain market-based rate authority, a public utility must file an application with the Commission demonstrating that it and its affiliates lack or have mitigated market power in the relevant markets. Until November 2001, the Commission used what is called a hub-and-spoke analysis to define markets and market shares. If an applicant and its affiliates owned or controlled less than 20% in each market, the applicant was deemed to demonstrate lack of market power. The hub-and-spoke analysis was supplanted with the Supply Margin Assessment (SMA) in November 2001. The SMA changed both the way the markets were defined and the threshold to pass the screen, making it more difficult to demonstrate lack of market power.

Although the vast majority of wholesale power sellers have already obtained market-based rate authority, the market power analysis continues to be of substantial importance. Sellers are required to submit to the FERC an updated market analysis every three years in order to renew their authority to conduct transactions at market rates. The FERC can revoke its market-based rate authorization if it finds that market conditions have changed raising the possibility that an applicant and its affiliates can exercise market power.[77]

A. *Traditional Hub-and-Spoke Analysis*

The hub-and-spoke analysis was used by the FERC to define markets and evaluate generation market power for approximately the first ten

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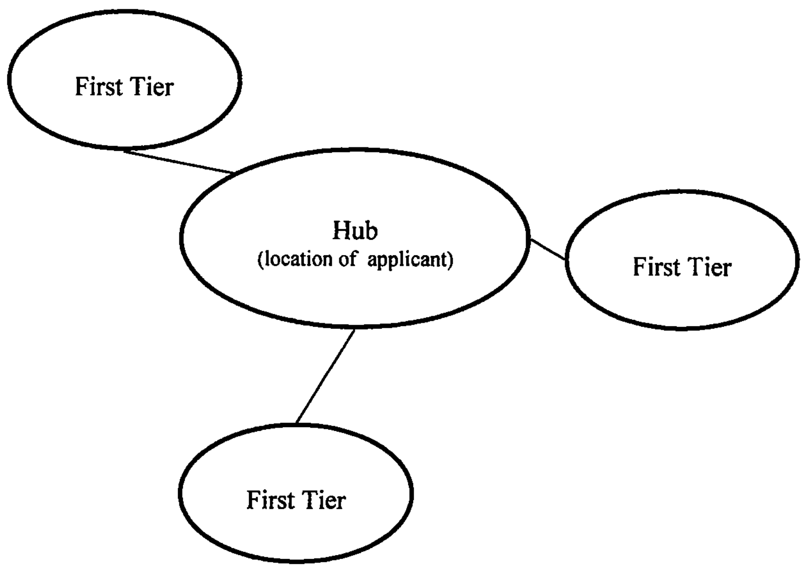
such authority was not burdensome since the relevant customers, generally municipal utilities or rural electric cooperatives, already purchased their power under long-term contracts. However, as retail access unfolds, such restrictions become more problematic.

75. This includes 506 Independent Power Marketers, 170 Affiliated Power Marketers, 331 Affiliated Power Producers, 96 Traditional Investor Owned Utilities, and 141 Other Utilities. *See generally* FEDERAL ENERGY REG. COMM'N, *Power Marketers Info., at* http://www.ferc.gov/electric/ pwrmkt/ pwrmkt.htm (last revised Mar. 14, 2002).

76. Of course, this need not be the case. The Commission could specify safe harbor provisions in terms, for example, of the size of an applicant relative to a region that would exempt most parties currently holding market rate authority. Having so done, it then could specify a more rigorous test for those who do not qualify for the safe harbor.

77. This is precisely what happened in the AEP, Entergy, and Southern Companies triennial reviews. *See generally* Order on Triennial Market Power Updates and Announcing New, Interim Generation Market Power Screen and Mitigation Policy, *AEP Power Marketing (AEP)*, 97 F.E.R.C. ¶ 61,219 (2001).

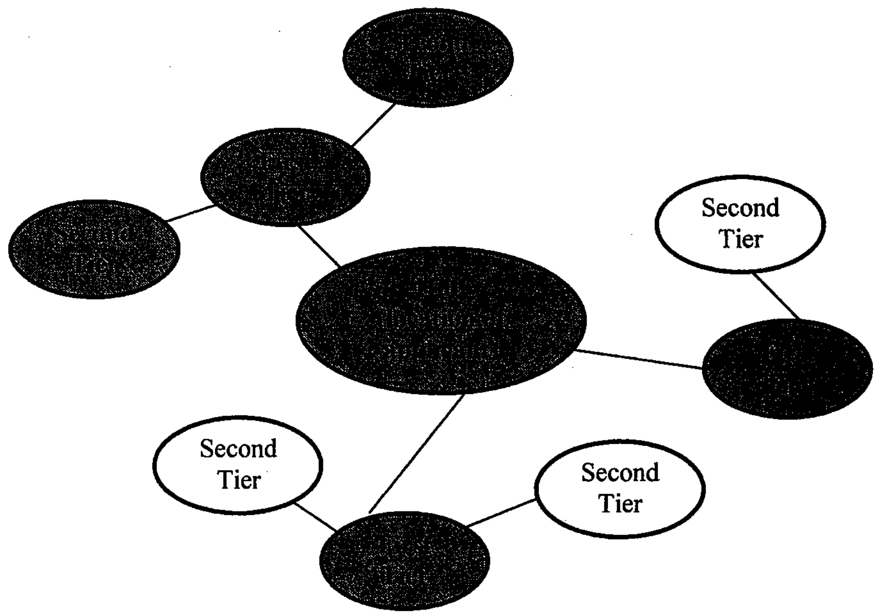
years of market based pricing reviews (*i.e.,* 1989 to 2001). The analysis starts by considering the control area where the facility (or facilities) for which that applicant is seeking market-based rates is located. This control area is called the hub. The market is defined as the hub plus every directly interconnected (or first-tier) control area.



Once the market is defined, the applicant's market share is evaluated using two different measures: total capacity and uncommitted capacity. Applicant's market share of total capacity is calculated by dividing the total installed capacity of applicant-owned generation by total installed capacity in the market. Uncommitted capacity is a more narrow measure that excludes capacity that is dedicated to native load. The applicant passes the hub-and-spoke screen for this market if its market shares are less than 20% using both measures.

In addition to this hub market, a number of additional markets are evaluated in some cases. In particular, if the applicant is vertically integrated and owns transmission facilities, the FERC also requires an analysis of all of the applicant's first-tier control areas. In such cases, a new market is defined for each first-tier control area, which includes the first-tier control area and each control area that is directly interconnected to it and the applicant.[78] The following diagram highlights one of these first-tier markets.

78. If the applicant does not own transmission facilities, the market includes only the utilities interconnected to the first-tier control area.



Market shares based on total capacity and uncommitted capacity are again calculated for each of these first-tier markets. An applicant must have less than a 20% market share in every market to pass the screen.

The hub-and-spoke analysis initially may have been reasonable in the context of traditional utilities, in which only a small portion of aggregate electricity supply was traded in the wholesale market. The remainder was dedicated to native load, so that the wholesale market effectively was a secondary market for power. Such trading between large utilities could be evaluated using a simple hub-and-spoke method. As wholesale competitive markets have grown and some retail markets have been deregulated, the limits of the method have been exposed. The primary drawbacks of the hub-and-spoke analysis were that: 1) limited transfer capability between control areas was not considered in the definition of the markets; 2) as independent generators came into the market and retail access programs were implemented, it became very difficult, if not impossible, to calculate uncommitted capacity measures, as information on private contracts is not readily available; and 3) virtually no utility failed the screen, thereby calling into question whether the test could discern potential problems.

B. Supply Margin Assessment

Due to increased concerns about the competitiveness of markets, partly resulting from a lack of progress in the formation of RTOs, the FERC, on November 20, 2001, adopted a new and more stringent generation market power analysis to be applied to market-based rate applications, called the SMA. Under this new approach, a supply margin is calculated as the difference between the installed capacity in a market and peak demand.[79] If an applicant has more generation capacity than the supply margin, its generation necessarily must be used at peak times and thus, the applicant is judged to be a pivotal supplier. A supplier in a such a pivotal position theoretically could raise the market price to an arbitrarily high level, assuming that demand is inelastic and buyers would pay such a price. Because the applicant's generation is compared to a supply margin that includes this same generation, the test is equivalent to asking whether rival supply is adequate to serve all of peak demand. If the answer is yes, the applicant's generation necessarily must be less than the supply margin, and vice versa.

The SMA will be applied on an interim basis while the Commission is reviewing new methods for analyzing market power. The SMA replaces the hub-and-spoke analysis, modifies the way in which markets are defined, and establishes new criteria for assessing lack of market power. Sales into an ISO or RTO with an approved market power monitoring and mitigation program are exempt from a requirement to perform an SMA analysis.[80]

The utilities comprising a geographic market in the SMA are identical to those analyzed under the hub-and-spoke method, except that the SMA explicitly incorporates inter-control area transmission constraints. Instead of including all the capacity of interconnected control areas when examining a control area market, the size of the market is limited to the hub plus that subset of generation that can reach the hub given the available transmission capability. This modification reduces the size of each market very substantially in comparison to the hub-and-spoke method. All generation capacity internal to a control area is included in the market, but external capacity is limited to that which can be imported over existing transmission facilities. Moreover, total capacity is used for the applicant, but uncommitted capacity is used for non-applicants outside of the control area.[81]

The SMA clearly raises the bar that an applicant must jump in order to show lack of market power. However, the SMA has a number of drawbacks. For example, the SMA examines market conditions at only one point in time over the course of a year. It is difficult, if not impossible, to evaluate market power problems from such a limited examination. It is possible that an applicant could pass the SMA yet wield significant market

79. *Id.*

80. The reason for eliminating any screening analysis inside of such organizations is not clear, apart from the incentive created thereby for utilities to join RTOs. A difficulty with such an approach is that RTOs do not necessarily coincide with markets. It is possible that a relevant market for wholesale power could span two or more RTOs, given that an RTO's geographic boundaries are based on transmission ownership and not generation substitution.

81. In addition, information about uncommitted capacity for non-applicants inside of the control area has been requested by the FERC staff in at least one case. Letter Advising Duke Energy North Am. that the 12/12/01 Submittal Containing Several Agreements & A Market-Based Rate Tariff is Deficient under ER02-530, *Duke Energy Marshall, L.L.C.*, F.E.R.C. Docket No. ER02-530-000 (Feb. 7, 2002).

power during numerous periods during the year, due to intra-control area transmission constraints, day-to-day operational issues, prolonged outages, tacit collusion, etc. It is also possible that an applicant could fail the test at peak times and no others. If so, it is unlikely that a supplier that holds a pivotal position for only a few hours of the year could effectively wield the unlimited market power supposedly identified by the test.

Further, the SMA is equivalent to evaluating rival supply in relation to peak demand, as mentioned.[82] This means that the applicant's supply effectively is removed entirely from the market to see if rival capacity would be adequate to serve peak demand. Because of this, the applicant's market share does not matter at any time—not during peak periods or off-peak periods. Providing no structural indication of the applicant's market presence, the SMA is not suitable as the sole indicator of market power, as used under the FERC guidelines; however, it may be useful as an additional indicator if appropriately revised.

A traditional public utility that owns generation to serve native load in its control area will find it virtually impossible to pass the SMA screen, unless it is strongly interconnected to its neighbors or there has been robust development of merchant generating plants in the area. If a traditional utility were in a position to sell all of its output at market-based rates, the SMA indeed might have identified a serious problem. In fact, however, in virtually all cases where utilities have retained their generation, they also have retained most or all of their native load responsibility. In most states, there is no retail access at all. Retail customers are served at prices regulated by state regulators and nearly all of the utility's capacity serves native load that SMA implicitly assumes must buy at market rates.

Hence, the SMA both overstates the size of the market to be served (since native load does not buy at market rates) and the amount that the utility has available to sell (since most of its capacity is used to meet native and requirements load). Thus, while the SMA may properly identify an incipient problem that could develop with full retail access (*i.e.*, after transitional pricing arrangements lapse), it creates a host of false positive indicators of market power in the meantime.

The simplest fix of this main problem with the SMA would be to replace the control area peak load with the peak load of all entities that are in fact are served at market rates and over which the applicant potentially could exert leverage. This would include none of the native load served at regulated prices or the load of other entities that is served by dedicated resources or long term contracts. Corresponding to this, all suppliers would be assessed using uncommitted capacity. Appropriately, a SMA revised in this manner would identify a traditional utility as failing the test only when its obligation to sell at regulated prices had substantially lapsed.

82. Peak energy demand understates the actual requirements of the system, which include additional capacity for operating reserves and other ancillary services.

VI. MONITORING AND MITIGATION

An important element of the FERC's market pricing program is likely to be tight oversight and enforced mitigation based on the Commission's interpretation that a rate resulting from an exercise of unilateral market power is not just and reasonable under the FPA. The FERC most likely will continue to screen market pricing applications and address market power concerns in advance to the extent possible. However, a major element of the FERC's regulation in the future will be monitoring and some form of mitigation, both of which are likely to be substantially more intrusive and intervening than past efforts.

The FERC has required market power monitoring to be conducted in conjunction with the formation of ISOs in the past and the Commission will continue to impose such requirements as RTOs are established in the future. The monitoring function will be carried out by an independent market monitor with the assistance of an internal monitoring unit of the RTO.[83] The monitor provides market reports to the RTO and can present its findings directly to the FERC or to the antitrust agencies. The monitor is likely to review hour-by-hour performance of individual generating units, including bidding behavior, unit availability, and products provided (*e.g.*, energy, reserves, regulation or capacity). The monitor will have some ability to question generation owners about any suspected strategic behavior. The RTO, with the advice of the monitor, will have some authority from the FERC to take action to mitigate behavior that exceeds limits established and approved in advance by the FERC. The mitigation may take the form of revising bids submitted to the RTO's centrally facilitated markets (*e.g.*, real-time energy markets, day-ahead energy markets, or installed capacity markets) as is currently done by the New York ISO, imposing bid or price caps, implementing must-offer requirements, or in extreme cases, assisting the FERC in ordering refunds.

As mentioned, the FERC staff recently has taken the view that unilateral behavior, such as the withholding of capacity, constitutes impermissible behavior under the FPA. The Commission has proposed that all market-based pricing authorizations on file at the FERC contain language that prohibits the holder of the authorization from withholding capacity or engaging in behavior that would violate the antitrust statutes. The Commission has proposed to take such action under section 206 of the FPA, which gives the Commission the authority to investigate and set the rules, regulations, and practices affecting rates, as well as the wholesale rates them-

83. The independence of the market monitor is not yet well defined. The RTO that the market monitor works with is also "independent" under FERC rules. The relation between the RTO and the monitor is evolving. At a minimum, it would seem that independence of the monitor requires that the monitor be able to submit reports to regulators directly, without first being reviewed by the RTO. Any enforcement of mitigation rules is likely to be implemented by the RTO, perhaps with the advice of the monitor. Because the monitor is acting as part of a FERC-approved oversight program, it is likely that the RTO could not dismiss the monitor without the consent of the FERC. Other requirements for independence can be expected to evolve as the FERC gains experience with this new institution.

selves, to ensure that they are just and reasonable.[84]

Moreover, in a recent order implementing its SMA test, the Commission initially imposed a particularly harsh form of mitigation on utilities failing its SMA test, although the requirement has been suspended pending further proceedings.[85] Under *AEP*, the mitigation would have required the utilities to sell power in their internal markets at incremental costs, to buy power at their decremental costs, and to post these costs on the Internet. This requirement to trade apparently applies to internal trading within the control area of the utility failing the SMA test, and does not appear to restrict trading of the utility outside of that control area. The price was specified as a so-called "split-savings rate," which is the difference between the seller's incremental costs and the buyer's decremental costs.[86] The Commission has defined two forms of withholding that would be problematic.[87] Economic withholding occurs when an economical unit (one with marginal costs less than the market price) is bid into a market at a price higher than the market price so that no buyer accepts its bid. Physical withholding occurs when the unit is not made available to the market when its marginal cost is less than the market price.

It appears that the Commission may be interested in an hour-by-hour, unit-by-unit approach to system oversight that would review management's decisions to start-up, run, shut-down, maintain, and overhaul each piece of generating equipment of any size attached to the grid.[88] While it is possible to understand that the FPA, with its just and reasonable standard, can be interpreted to go further than the antitrust statutes in proscribing behavior during the transition from regulation to competition, it does not seem reasonable to engage in this degree of micro-regulation. Traditional cost-based regulation did not impose specific cost-based prices on each wholesale transaction, but rather allowed for substantial flexibility of pricing within a zone of reasonableness. The overall rate of return used to determine average corporate rates could be determined only within a few percentage points. Any additional precision was recognized as spurious.

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84. Order Establishing Refund Effective Date and Proposing to Revise Market-Based Rate Tariffs and Authorizations, *Investigation of Terms and Conditions of Pub. Util. Market-Based Rate Authorization*, 97 F.E.R.C. ¶ 61,220 (2001) [hereinafter November 20 Order].

85. *AEP*, 97 F.E.R.C. 61,219 (2000).

86. The Commission's logic is somewhat unclear. In the past, the Commission has allowed split-savings rates under its cost-based regulation, even before market-based rates were first approved in the early 1990s. If the Commission concludes that market rates cannot be approved (based on the SMA test or any other grounds), and requires instead that power be sold under the split-savings form of cost-based regulation, it is not clear why it would impose a requirement to deal. No such requirement was previously attached to split-savings rates. It may be that the Commission has concluded that split-savings rates are a form of market pricing, and that, as such, must-deal requirements are needed, but this is uncertain.

87. November 20 Order, *supra* note 84.

88. The discussion paper prepared by Commission staff indicates that "[m]onitoring of physical withholding of generation should be a primary focus of market monitoring. However, bright-line enforceable rules preventing such behavior may be difficult to administer and inferior to other mitigation measures." FERC Staff Strawman, *supra* note 22, at 7.

Likewise, individual wholesale transactions could be executed without routine scrutiny. Just as the FERC's cost-based regulation represents a balance between the regulatory need for tough-minded oversight and the wholesale market need for trading flexibility, its market-based regulation must provide a similar balance.

If the FERC embraces a monitoring and mitigation approach that reviews individual unit run-versus-withhold decisions, it could inject more, not less, regulation into wholesale markets.[89] There would be numerous difficulties in implementing such a remedy.[90] First, there is no general "duty to deal" under the antitrust laws.[91] Outside of the electricity industry, firms generally have the freedom to sell or not to sell as they please. It would seem that the owner of a merchant generator would have substantial freedom to destroy or retire its generating units as it deems appropriate without pre-approval from the FERC or other rate authorities.[92] It would appear inconsistent that a firm could permanently withhold capacity from a market, but be restrained in a temporary withholding.[93] It may be that the FERC intends to perpetuate the traditional "obligation to serve." If so, this would be an important detour on the way to competitive markets that should be discussed and clarified.[94]

Second, there is much ambiguity in identifying and separating "good withholding" from "bad withholding" because of the inability to measure a supplier's opportunity costs. As recognized by most, if not all, commentators, an owner of a generating unit with a marginal running cost that is less

89. The Commission has taken a step in this direction in its Order on Rehearing of Monitoring and Mitigation Plan for the California Wholesale Electric Markets, Establishing West-wide Mitigation, and Establishing Settlement Conference, where the Commission reaffirmed that all public and non-public utilities that own or control non-hydroelectric generation in California must offer power in the ISO's spot markets and all public and non-public utilities in the remainder of the WSCC must offer any non-hydroelectric resource in the spot market of their choosing through September 30, 2002. 95 F.E.R.C. ¶ 61,418 (2001).

90. For additional discussion, see Kenneth L. Glazer & Abbott B. Lipsky, Jr., *Unilateral Refusals to Deal Under Section 2 of the Sherman Act*, 63 ANTITRUST L. J. 749 (1995).

91. Comments of the Staff of the Bureau of Econ. and the Off. of Gen. Couns. of the Fed. Trade Comm'n, *Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorization,* F.E.R.C. Docket No. EL01-118-000 at 10 (Jan. 7, 2002)(regarding November 20 Order) [hereinafter FTC Staff Comments]. Staff points out that cases where courts have placed limits on a firm's freedom to refuse to deal have involved monopolists engaging in other behavior that has violated the antitrust laws. Refusing to deal so as to charge a monopoly-based, profit-maximizing price is not illegal, in Staff's view.

92. This may be ambiguous given the FERC's Notice of Termination rule (18 C.F.R. § 35.15 (2002)). Heretofore, such notice generally has been a routine matter applying to the provision of service. If a merchant could continue to provide contracted levels of service without the use of a particular generating unit, it seems unlikely that such Notice would be used to prevent a unit's retirement. Certainly, non-rate regulation of states, *e.g.*, environmental and safety regulations, would apply.

93. FTC Staff Comments, *supra* note 91, at 8 n.13

94. For example, would such an obligation extend to merchant plants or just to plants built to serve native load in a prior regulatory regime? What about plants divested by traditional utilities as part of retail market restructuring that are now owned and operated by merchants? Does FERC intend to adopt abandonment rules, such as those used in its regulation of natural gas pipelines? How would such regulation interact with state siting laws?

than the current hour's price nevertheless may have a legitimate reason for not running the unit. Unit commitment parameters (such as start-up costs, minimum running times, and minimum shut-down times) are routinely considered in the day-to-day decision about how to commit (*i.e.,* start up and run at least at minimum output) and use a particular generating unit.[95] For example, unit commitment decisions for most steam units are based on a comparison of the unit's parameters with expected market conditions during the next twenty-four to forty-eight hours or so. Any after-the-fact second-guessing of these decisions necessarily would need to account for management's expectation of prices, a regulatory exercise sure to be contentious. In addition, a generating unit's opportunity costs involve an assessment of producing now versus producing at a later time when prices might be higher. This is especially so for energy-limited units, such as hydroelectric facilities subject to annual availability of water or thermal plants subject to annual pollution emission limits. Producing now versus producing later is a legitimate consideration for such units. And all plants occasionally must be taken off-line for routine maintenance or overhaul, the timing of which is part of management's profit-maximizing business plans that could be second-guessed under a no-withholding policy.[96]

Third, the monitoring of economic withholding will be especially difficult outside of bid-based markets with a single market-clearing price, such as the real-time energy markets in the existing ISOs (*i.e.*, New York, New England, PJM, and California). In the ISO markets, all suppliers know that they will be paid the market-clearing price regardless of their own bid, as long as their bid is "in the money." This creates a theoretical incentive for suppliers to bid their own costs. No similar incentive exists outside of such organized markets where suppliers are paid what they bid. In "pay as bid" markets, suppliers have an incentive to guess at the expected market-clearing price in order to be paid full value.[97] In such markets, mistakes will be made and after-the-fact review would uncover instances in which bids from economical units were not accepted by buyers. It would be virtually impossible to distinguish mistaken bidding from intentional strategic behavior in such markets.[98]

95. For a general discussion of unit commitment issues, see Scott Harvey & William Hogan, *Market Power and Withholding,* submitted by Edison Electric Institute in F.E.R.C. Docket No. EL01-188-000, at 7-8 (Dec. 20, 2001), *at* http://ksghome.harvard.edu/~.whogan.cbg.ksg/.

96. FTC Staff Comments, *supra* note 89. Harvey & Hogan, *supra* note 95, at 6-7; Indicated Generator's Sumission fo Statement of Alfred E. Kahn, *Investigation of Terms and Conditions of Pub. Util. Market-Based Rate Authorizations*, F.E.R.C. Docket No. EL01-118-000, at 4 (Jan. 7, 2002) [hereinafter Kahn Statement]. Marginal opportunity costs is a theoretically sound concept that is virtually impossible to quantify in practice. The FERC will need to be able to recognize false claims of the ability to do so by its prospective monitors.

97. Alfred E. Kahn et. al., *Pricing in the California Power Exchange Electricity Market: Should California Switch from Uniform Pricing to Pay-as-Bid Pricing?* (Jan. 23, 2001), *available at* www.criterionauctions.com/documents/kahn_cramton_porter%20et%20al.pdf (commissioned by the Cal. Power Exch.), for a discussion of incentives under uniform versus pay-as-bid pricing.

98. For additional discussion, see Harvey & Hogan, *supra* note 95, at 11-12, and FTC Staff Comments, *supra* note 89, at 13-14.

If the FERC is to rely on monitoring and mitigation in the future, some flexible approach must be found that does not micro-manage the firm and thereby risk more regulation instead of less.[99] The stakes are significant. One of the most important features of competitive markets is the transfer of the investment decision (and associated risks) from the regulator to the private sector. Private sector investment in generation capacity is needed to serve future demand. Investment incentives can be muted by intrusive regulation. The regulatory challenge is to find a way to ensure satisfactory performance of spot markets (*i.e.*, volatile, but yet reasonable wholesale energy prices), while providing competitive opportunities for new investment. As the FERC has recognized in the context of the California experience, the first step in meeting this challenge is to eliminate flaws in the underlying market design. Two important aspects of market design are: (1) enabling price-responsive demand through better metering; and (2) ensuring adequate generation capacity.[100] Beyond these measures, there appear to be two broad approaches for implementing a monitoring and mitigation program: price or bid caps versus review/mitigation of individual supplier behavior.[101]

Price or bid caps potentially have several advantages. A price cap can be tightened or loosened depending on market conditions without detailed review of supplier behavior. As a temporary measure until price-responsive demand becomes an important aspect of electricity markets, price caps can moderate price excursions and help to maintain confidence in the performance of competitive markets, thereby avoiding inefficient re-regulation. Such caps could be set at a level that would not overly discourage investment.[102] Such an approach may be useful in the transition from regulation to competition in the electricity industry. The FERC recognizes this and has imposed loose price caps on some products at certain times in all the early ISOs (PJM, New York, ISO-NE, and California) as well as on all sellers in the western markets.[103]

99. A similar point has been made by Prof. Kahn arguing that the FERC's objective of preventing market abuses is unexceptional, but its implementation is misguided. Regulatory review of managerial decisions about whether or not to run particular generating facilities, in his view, would invite constant argument about whether or not such decisions are legitimate. Moreover, given that these decisions necessarily would be based on managerial judgments about marginal opportunity costs, they cannot be demonstrated to be right or wrong. Kahn Statement, *supra* note 96, at 1.

100. There is considerable debate about how this latter objective is best achieved. This debate revolves principally around the need for load-serving entities to demonstrate their entitlement to sufficient reserves to ensure that they can meet their loads reliably. While this debate is beyond the scope of this paper, it appears quite likely as of this writing that the Commission will adopt some form of installed capacity requirement as part of its standard market design.

101. Alfred E. Kahn, Standards for Antitrust Policy, 67 HARVARD L. R. 28 (1953) (market performance in terms of good or bad economic results is difficult to measure); Ronald A. Cass & Keith Hylton, *Antitrust Intent*, 74 S. CAL. L. R. 657 (2001)(antitrust laws is focus of behavior of companies and not whether prices are too high or too low).

102. Kahn Statement, *supra* note 96, at 6-8 for additional discussion.

103. *AES Redondo Beach, L.L.C.*, 83 F.E.R.C. ¶ 61,358 (1998) (California); *ISO New England, Inc.*, 97 F.E.R.C. ¶ 61,090 (2001) (New England); *New York ISO, Inc.*, 97 F.E.R.C. ¶ 61,095 (2001) (New York); *Atlantic City Electric Co.*, 86 F.E.R.C. ¶ 61,248 (1999) (PJM).

Going beyond price caps to review/mitigation of individual supplier behavior potentially poses all of the problems discussed above. While it would be better if this approach could be avoided, special aspects of electricity markets suggest that some version of this approach may be needed. For example, local reliability needs can require certain generators to run, and knowing this, the owner of the generator could demand and receive a high price reflecting his strategic position. This type of local must-run condition must be addressed through contractual or other supplier-specific approaches.[104] It is the expansion of such narrowly circumscribed programs to all suppliers that creates the possibility of major regulatory intervention.

Assuming that the FERC decides that some review to identify unreasonable withholding is needed, it will be important for the Commission to clarify how such programs will work and the standards that will be used in these assessments. Such rules and standards need to be developed in a public notice-and-comment proceeding in order for market participants to have a clear idea of the Commission's expectations. It also would be important for any supplier-specific enforcement to remain confidential, consistent with enforcement actions taken by the antitrust agencies. In this way, the market monitor could review supplier behavior for patterns of strategic withholding, and refer such matters to the FERC for further investigation and/or enforcement. If suppliers know in advance the behavioral standard to which they will be held and also know that violations will be enforced in a confidential manner by the Commission, the monitoring and mitigation programs may provide valuable assistance to the Commission without subjecting suppliers to overly intrusive micro-management. If, however, allegations of illegitimate withholding were subject to a public notice-and-comment process, the process itself would create an invitation for intervention that would soon drive suppliers back to the FERC's cost-based ratemaking, assuming that option remains open at the agency.

While it is too early to say with certainty what the Commission will do, recent indications are that it may impose a relatively detailed set of rules governing individual bidding behavior as part of the standard market design. These would be enforced by the RTO and its monitoring unit automatically—frequently on a before-the-fact basis. Such a shift in emphasis on the RTO's role from monitoring to mitigation would reflect a substantial retrenchment from the former confidence that the Commission placed in the competitive performance of electricity markets. While the implied level of caution may be warranted in view of the fragile political and public support for market deregulation, it may prove difficult to unwind in the future.

104. Such contracts are not without their own problems, however. Reliability-Must-Run contracts in California were litigated for years at the FERC.

VII. SUGGESTIONS AND CONCLUSIONS

A. *Wholesale Market-Pricing Authority at the FERC*

It is clear that the FERC is reassessing its approach to evaluating market power in the context of market pricing for wholesale power sales. It has abandoned its former guidelines based on the hub-and-spoke analysis, in which transmission limits were ignored. It seems unlikely that the interim SMA test will become the FERC's sole method, given its numerous problems (as discussed previously). Accordingly, the FERC will need to adopt a test that is analytically more rigorous without unduly adding to its own administrative burden. The Commission annually processes hundreds of wholesale pricing applications under section 205 of the FPA. By comparison, the FERC receives about two to ten merger applications annually and perhaps another fifty applications involving acquisitions that would require a competitive review under section 203 of the FPA. The Commission does not have the resources to review these pricing applications using complex analyses, such as the delivered price test, let alone using a more advanced process, such as behavioral analysis.

Nor is such an analysis needed. The FERC apparently intends to rely in substantial degree on the monitoring and mitigation programs of the RTOs it approves. The mitigation can be tailored to the maturity of the spot markets within the RTO. Widely available, bid-based energy markets for balancing services within an RTO, combined with price-responsive demand, are likely to require only a light-handed mitigation program as a general matter, assuming that an effective monitoring program is available to alert regulators of market flaws and any other ongoing problems. RTOs with less mature markets may be required to institute more stringent mitigation programs. In these circumstances, the FERC's screen for market-pricing authority needs to identify potentially large problems and does not need to address smaller concerns that can be handled through the monitoring and mitigation program.

A possible screen that could serve this function would be market shares based on a transmission-limited version (most likely based on simultaneous TTC) of the hub-and-spoke analysis.[105] This method could assess market positions in installed capacity and uncommitted capacity (accounting for native load and other commitments) while limiting the market participation of external suppliers to that which could be imported. The screen could be passed if either total or uncommitted capacity is less than some threshold, say the 20% to 30% criterion currently used by the FERC. This screen could be supplemented with the SMA, revised to reflect uncommitted capacity and market load as mentioned above, as an added check on the possibility that a supplier might gain a pivotal position in the market. No matter what the test, the efficiency of regulation would benefit if a safe harbor eliminated the need for minor market participants to file

105. Note that this is the transmission architecture of the SMA test.

analyses.

As a separate matter, there is a question of whether the FERC should continue to rely on a case-by-case review (seller lacks market power) or begin to assess the competitiveness of markets. While assessment of overall market competitiveness would provide useful information to the FERC as a general matter, it is difficult to see how the agency could entirely discontinue its assessment of individual suppliers. As an economic matter, it is possible that a seller would lack market power in a market that is otherwise non-competitive, perhaps because some other supplier is dominant. A small supplier should not be subject to the Commission's cost-based filing requirements simply because some other supplier dominates the market. As a legal matter, suppliers have certain rights under sections 205 and 206 of the FPA, and the Commission must review pricing applications that are submitted. If the Commission were to revoke a supplier's market-pricing authority on the grounds that the overall market is not competitive, the supplier presumably would have the right to file its own market study indicating why it does not have market power or, alternatively, explaining how it believes the Commission erred in concluding that the overall market is not competitive. In either case, the Commission's own review of markets would not seem to be a complete substitute for an applicant's study of its own market power (or lack thereof).

B. Merger Review at the FERC

Despite all of the drawbacks to the FERC's delivered price test, we do not believe it would be wise to abandon that approach in the near term. Somewhat greater analytical rigor could be achieved if an opportunity cost model were used to inform the definition of the relevant geographical market in a structural analysis. However, taking such a step would involve substantially more complex modeling without the benefits of moving away from a structural analysis. If it were possible to adopt a behavioral model along with appropriate screening criteria, our recommendation might be different, but without appropriate screening criteria, the role of behavioral modeling should be limited to providing additional review.

C. Merger Review at the DOJ/FTC

The antitrust agencies tend to use behavioral analysis in the HSR review process, but only infrequently have engaged in quantitative behavioral modeling due to time limitations. While behavioral modeling can be useful in theory, it has many drawbacks, as discussed above. Foremost among these is the absence of any screening criteria. In those few instances when the agencies have relied on such modeling, applicants have been frustrated by an inability to review the agency's analysis.[106]

106. The agencies may be reluctant to turn HSR review into a battle among models and modelers.

D. *Market Monitoring and Mitigation*

Perhaps the FERC's biggest challenge will be to create an effective monitoring and mitigation program that does not micro-manage generating unit commitment and usage decisions. Administered price and bid caps, for example, are notorious for inflexibility and working against the needs of the market. Caps that are loose enough to not interfere with the market in the short run may be perceived as providing too little protection against high prices in the longer term. Likewise, administrative review of behavior to identify withholding behavior in violation of the FPA risks not allowing markets to perform in the intended manner. More intensive review during shortages, for example, seems likely and would be intrusive just at the time when market prices are needed to signal the need for investment. Choosing market-based, as opposed to cost-based, pricing while embracing a no-withholding standard, creates an unavoidable tension between competition and regulation that the Commission will need to manage.

E. *Conclusions*

We began by acknowledging that "electricity is different". Unlike, for example, airlines, it is not sufficient to simply remove price regulation and let suppliers go at each other. Experience thus far illustrates that the gaming of immature market rules can substantially impact prices, at least for short periods. Nonetheless, we believe that mechanisms can be devised to ensure that such problems do not overwhelm the advantages of competition.

While this focus of this paper has been on analysis and enforcement, a more fundamental question is the extent to which regulators and their constituents will accept that workably competitive markets are imperfect, or instead will insist on performance consistent with the textbook concept of perfect competition. The mere existence of regulatory forums to address performance falling short of the latter standard can create a bias toward regulatory intrusion. While the Commission's ten-year promotion of competitive wholesale electricity markets has been impressive, the next few years will determine whether the industry will continue its competitive evolution or retrench to *de facto* reregulation.