RECENT DEVELOPMENT

ONE STEP IN THE RIGHT DIRECTION: 
AN ANALYSIS OF FERC'S REPORTING REQUIREMENT FOR STATUS CHANGES FOR PUBLIC UTILITIES WITH MARKET-BASED RATE AUTHORITY

The Federal Energy Regulatory Commission ("FERC" or "Commission") promulgated Order 652 to establish criteria that public utilities must follow to maintain market-based rate authority.\(^1\) Market-based rate authority allows utilities to price electricity at “whatever price the market will bear at any given place and point in time, subject to a nationwide cap of $1,000 per MWh ("megawatt-hour") if the “seller and its affiliates do not have, or have adequately mitigated, market power in generation and transmission and cannot erect other barriers to entry.”\(^2\) On

1. Order 652 established guidelines concerning events that would trigger a reporting obligation and a new inquiry into the propriety of market-based rate authority for sellers. The Commission, acting in accordance with power granted in section 206 of the Federal Power Act eliminated the option to delay reporting events until the submission of a market-based rate seller's updated market power analysis. Furthermore, Order 652 required the incorporation of the reporting requirement in the market-based rate tariff of each entity currently authorized to make sales at market-based rates and for future applicants. Reporting Requirement for Changes in Status for Public Utilities with Market-Based Rate Authority, Order No. 652, 70 Fed. Reg. 8253–301 (Feb. 18, 2005) [hereinafter Order 652]; see also Federal Power Act § 206, 16 U.S.C. § 824e(a) (2000).

2. James Bushnell, Looking for Trouble: Competition Policy in the U.S. Electricity Industry, in ELECTRICITY DEREGULATION 256, 266–71 (James M. Griffin & Steven L. Puller eds., 2005). See also Gerald Norlander, May the FERC Rely on Markets to Set Electric Rates?, 24 ENERGY L.J. 65, 73–74 (2003) (noting that: (1) market-based rate authority essentially affords an energy company the ability to price electricity according to the market as dictated by supply and demand; and (2) this program has been in existence since FERC outlined the procedure in the 2002 Standard Market Design ("SMD") proposal). See Hon. Joseph T. Kelliher, Market Manipulation, Market Power, and the Authority of the Federal Energy Regulatory Commission, 26 ENERGY L. J. 1, 13 (2005) (noting that the Commission does not rely solely on a finding that the market-based rate applicant lacks market power, but also relies on “reporting requirements in order to assure that rates are just and reasonable and not subject to market manipulation.”);
June 16, 2005, FERC issued findings in response to Requests for Rehearing and Clarification of Order 652 by Constellation Energy Group ("Constellation"), the Edison Electric Institute ("EEI") and the Alliance of Energy Suppliers, Reliant Energy, and the Electric Power Supply Association ("EPSA"). In the FERC Rehearing, FERC clarified that market-based rate sellers may offset decreases of generation with increases in generation. In addition, FERC specified the tariff requirements for market-based rate sellers and made alterations to the reporting process, including, among other things, the reporting of generation increases exceeding 100 MWh, for supply contracts lasting more than one year, and the transfer of "control" over generation or transmission facilities. These alterations imposed by FERC attempt to clarify ambiguities associated with reporting status changes and reduce transaction costs in competitive energy markets.

This paper will provide: (1) background information regarding market power assessments and subsequent grants of market-based rate authority; (2) the evolution of reporting requirements for market-based rate sellers; (3) a description of Order 652 as clarified by FERC; (4) an examination of the informational asymmetries and market failures perpetuated by the newly enacted reporting requirements; and (5) an evaluation of FERC’s reactive policies in addressing the changing patterns of competition in electricity markets.

I. MARKET POWER ASSESSMENTS AND MARKET-BASED RATE AUTHORITY

Previously, public utilities were able to recover the costs of generation and procurement of electricity plus a regulated rate of return predetermines by the FERC or the state public utility commission through the cost-based rate regulatory scheme. The

David G. Tewksbury & Stephanie S. Lim, Applying the Mobile-Sierra doctrine to Market-Based Rate Contracts, 26 energy L. J. 437, 447 (2005).  
3. Order on Rehearing Reporting Requirement for Changes in Status for Public Utilities with Market-Based Rate Authority, 111 F.E.R.C. ¶ 61,413 [hereinafter FERC Rehearing].  
4. In terms of electricity transactions, a tariff is "a compilation of all effective rate schedules of a particular company or utility. Tariffs include General Terms and Conditions along with a copy of each form of service agreement." FERC: Glossary, http://www.ferc.gov/help/glossary.asp#T (last visited Sept. 12, 2006).  
5. FERC Rehearing, supra note 3.  
6. FERC defines cost-based rate authority as "a ratemaking concept used for the design and development of rate schedules to ensure that the filed rate schedules recover only the cost of providing the service." FERC: Glossary, http://www.ferc.gov/help/glossary.asp#T (last visited Sept. 12, 2006). Typically, FERC
public utility would file a rate case with the state public utility commission or the FERC and the regulatory body would determine the rates to be charged to customers using the “just and reasonable” criteria established under the Federal Power Act. Cost-based rate authority prevented end-users from enjoying reduced rates for electricity associated with competition because public utilities were allowed to pass the costs of exorbitant business expenses and other investments on to customers based on the relatively high success rate of rate-based filings. The advent of electricity deregulation was the catalyst FERC needed to utilize the flexibility afforded by the broad language of “just and reasonable.” This term allowed FERC to widely grant market-based rate authority that mimicked competitive markets in other industries. Market-based rate authority provides a remedy for the inefficiencies of cost-based

allows for the inclusion of a “reasonable” rate of return in addition to the cost-based rate, in accordance with Section 206 of the Federal Power Act. See Federal Power Act § 206 (focusing on the “just and reasonable” language of the statute). Utilities are afforded a “reasonable” rate of return plus cost-based rates in a cost-of-service environment. See Scott B. Finlinson, The Pains of Extinction: Stranded Costs in the Deregulation of the Utah Electric Industry, 1998 Utah L. Rev. 173, 189–90 (1998). Essentially, the FERC or the state public utility commission sets a rate in which a utility may charge customers via a rate case with a “just and reasonable” rate of return attached to ensure the recovery of stranded costs. Id.

8. Rate based filings are “the value of property upon which a utility is permitted to earn a specified rate of return as established by a regulatory authority.” FERC Glossary, http://www.ferc.gov/help/glossary.asp#R (last visited Sept. 12, 2006). Utilities recover their costs plus a “reasonable” rate of return when filing their rate case with the state public utility commission. A rate case is simply the proceeding before FERC or the state public utility commission that determines the rates to be charged for the services provided by a public utility. See Stefan H. Krieger, Problems for Captive Ratepayers in Nonunanimous Settlements of Public Utility Rate Cases, 12 Yale J. on Reg. 257, 280–81 (1995).
9. Because market-based rate authority allows energy companies to price according to market fluctuations, investor-owned utilities bear the greatest risk in such a pricing environment. Investor-owned utilities are privatized facilities that are not financed by government subsidies. Therefore, price fluctuations increase the risk that the utility will not be able to cover costs and provide investors with the rate of return typically awarded in the cost-of-service regime. The inability of a market-based rate regime to provide stability and certainty in the context of rates of return creates disincentives for investors to finance new utility projects, which may undermine the reliability and security of the infrastructure and energy supply.
10. See Bernard S. Black & Richard J. Pierce, Jr., The Choice Between Markets and Central Planning in Regulating the U.S. Electricity Industry, 93 Colum. L. Rev. 1339, 1385 (1993). Among the inefficiencies of cost-based rate regulation in electricity markets include the ability of the utility to pass on the cost of generation inefficiencies to consumers, to pass on the costs of imprudent investments rate designs were often based on average rather than marginal cost of production, which often results in higher rates for consumers, and the utility did not internalize any environmental costs associated with electricity generation as the utility could pass these costs onto consumers as a cost of operations. Id.; see also Joseph P. Tomain & Constance Dowd Burton, Nuclear Transition:
rate authority, so long as the public utility does not amass market power\(^\text{11}\) that FERC deems anticompetitive.\(^\text{12}\)

FERC conducts market power assessments to authorize or deny market-based-rate authority, but FERC can only initiate a market power assessment once a competitor or an interested party files a complaint with the Commission in accordance with section 206 of the Federal Power Act.\(^\text{13}\) In April 2004, FERC created a new market power screen that includes two interim indicative\(^\text{14}\) screens: the Uncommitted Pivotal Supplier (“UPS”) and the Uncommitted Market Supplier (“UMS”) analyses.\(^\text{15}\) The new UPS and UMS screens only apply to utilities not subject to ISO\(^\text{16}\) market power screens, which resemble the “hub and


\(^\text{13}\) See Kim G. Bruno, Should Affiliated Marketers Be Treated As Insiders, 21 ENERGY L. J. 465 (2000); see also Order 652, supra note 1; Federal Power Act § 206. Generally, the FERC utilizes a four-part analysis to determine market power, which includes (1) whether an applicant for market-based rates or its affiliates have the potential to exercise generation market power; (2) whether an applicant for market-based rates or its affiliates have the potential to exercise transmission market power; (3) a consideration of other barriers to entry; and (4) the potential for affiliate abuse or reciprocal dealing. Press Release, Fed. Energy Regulatory Comm’n, Final Rule Requiring Holders of Market-Based Rates to Report Changes in Status Will Enhance Market Oversight (Feb. 9, 2005), available at http://www.ferc.gov/press-room/press-releases/2005/2005-1-02-08-05-mbr.asp. See also Electric-Market-Based Rates: How to Get Authorization, http://www.ferc.gov/industries/electric/gen-info/mbr.asp (last visited July 11, 2006).


\(^\text{16}\) The New York Independent System Operator (“ISO”) describes an ISO as:

... an entity sanctioned by the Federal Energy Regulatory Commission
spoke” approach previously utilized by FERC. After years of clamoring by investor-owned utilities over the ambiguity and subjectivity of the “hub-and-spoke” approach, FERC conducted a comprehensive review of its market-power tests and determined that the UPS and UMS market-power screens were the proper solution. The UPS market-power screen focuses

("FERC") for the purpose of managing the transmission system as the electric industry in the United States is restructured. An ISO controls the power system without special interest, and owns no generation, transmission or load. Therefore, the ISO is intended to run the system fairly, for the benefit of all market participants.


17. “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.” William H. Hieronymus et al., Market Power Analysis of the Electricity Generation Sector, 23 ENERGY L. J. 1, 37 (2002).

18. Id.; see also Bushnell, supra note 2, at 266 (describing the “hub and spoke” approach whereby a firm was considered to have amassed market power if FERC determined that the firm had 20% or more market share within the firm’s “home control area”).

19. Robert Varela, Do the Right Thing, PUBLIC POWER WEEKLY, Jan. 1, 2005, http://www.appanet.org/newsletters/washingtonreportdetail.cfm?ItemNumber=11643&sn.ItemNumber=0 (noting that, in reference to the hub-and-spoke test, “[i]nvestor-owned utilities howled so long and loudly—mainly in the halls of Congress—that the commission was forced to back off and never enforced the new test.”). Much subjectivity, on the part of regulators, is involved in defining the appropriate geographic market when conducting a market-power assessment under the “hub-and-spoke” approach, thus often resulting in unpredictable market definitions. Such unpredictability undermines the competitiveness of electricity markets given that the unpredictability or uncertainty decreases market transparency and necessitates increased risk premiums for investments in the infrastructure of electricity markets. Furthermore, the hub-and-spoke market-power analysis accounts for all capacity, “however expensive to run and however much the cost in losses and transmission charges. . . .” SALLY HUNT, MAKING COMPETITION WORK IN ELECTRICITY 314–15 (2002). Therefore, the market definitions in the hub-and-spoke approach took into account capacity that was unprofitable and not likely to even affect the market, thus resulting in inaccurate and ambiguous market definitions and, subsequently, assessments. For more about the problems associated with hub-and-spoke market-power assessments, see STEVEN STOFT, AN ANALYSIS OF FERC’S HUB-AND-SPoke MARKET-POWER SCREEN (Sept. 2001), http://www.eob.ca.gov/Attachments/stoftfinal.pdf.

20. The FERC determined the “uncommitted pivotal supplier analysis . . . will assess the potential of an applicant and its affiliates to exercise market power based on the control area market’s annual peak demand.” Antitrust Report, supra note 15, at 528 (citing AEP Power Marketing, Inc., 107 F.E.R.C. ¶ 61,018, at 61,060–61).

21. The uncommitted market supplier test “will assess the applicant’s and its affiliates’ market share of uncommitted capacity on a seasonal basis.” Id. (citing AEP Power Marketing, Inc., 107 F.E.R.C. ¶ 61,018, at 61,055). Furthermore, both the UMS and UPS market-power screens consider native load obligations and other contractual commitments of the applicant. Id.

22. See Craig R. Roach, Measuring Market Power in the U.S. Electricity Business, 23 ENERGY L. J. 51, 54 (2002) (highlighting that the basis for the 20% market share threshold in the “hub-and-spoke” approach is unclear and often criticized. This approach
on the ability of the utility to exercise market power unilaterally. Under UPS analysis, FERC considers native load and other firm contracts in calculating total uncommitted capacity at peak times. The UPS screen considers total transfer capacity through an analysis of simultaneous import capability to better assess the effect of transmission limitations on generation imports. The UMS screen indicates whether a supplier has a dominant position in the market, which also serves to illustrate unilateral market power and may indicate the ability of the utility to facilitate coordinated interaction with other sellers. UMS analysis evaluates the applicant’s share of seasonal uncommitted capacity. UMS analysis is also helpful because it considers the utility’s size relative to other market

is an indirect method in proving market power that fails to determine if market power was actually exercised. Additional problems exist in the actual definition of the “home control area.” FERC has failed to precisely delineate the breadth of the geographic area to be considered in a market power assessment, which greatly affects market mitigation strategies.


24. “Native load” refers to an end-user customers or device using electricity. ‘Native load’ is ‘load’ that is using electricity that is ‘native’ or geographically close to the generating plant. ‘Load should not be confused with [d]emand or an end-use customer that receives power from the electric system.” Samuel R. Brumberg, Getting the Camel Out of the Tent: Behind the Federal Energy Regulatory Commission’s Rise to Power and the Importance of States’ Continued Regulatory Oversight, 30 WM. & MARY ENVTL. L. & POL’Y Rev. 691, 693 n.10 (2006). “A load, then, is an individual consumer, while demand is the amount of electricity required by that consumer.” Id.

25. “Uncommitted capacity is total installed capacity less the needs of a supplier’s (utility’s) retail customers still receiving regulated service (“native load obligations”). Roach, supra note 22, at 53. 'Total "installed capacity is the sum of the capacity of all the power plants in the geographic scope of the market." Id. As Dr. Roach illustrates, the term “uncommitted” serves to reflect the fact that only some of the potential electricity suppliers have power plant capacity freed up to compete in the competitive wholesale market given that some electric markets are not completely deregulated. Id. Furthermore, uncommitted generating capacity serves to indicate competition for year-round electricity sales while total installed generating capacity indicates competition for short-term electric energy. Id. The uncommitted capacity and total installed generating capacity measures account for the temporal nature of competitive electricity markets.

26. Id.; see also Energy Terms, http://www.wisconsinpublicservice.com/farm/terms.asp (last visited July 11, 2006) (defining “peak demand” as both the greatest demand placed on an electric system as measured in kilowatts or megawatts and the time of day or season of the year when that demand occurs). It is industry custom that hours ending 6:00 through 22:00 are considered times of peak demand on a daily basis. The industry regularly utilizes heating-degree days (“HDD”) and cooling-degree days (“CDD”) to predict peak demand over longer periods of time and to price accordingly.

27. ICF Market Power, supra note 14.


29. ICF Market Power, supra note 14 (depicting UMS market power analysis as, essentially, a wholesale generation market power screen).
participants. A market-based rate applicant will pass the UMS screen if its market share of uncommitted capacity is less than twenty percent. FERC firmly believes that the combination of both the UPS and UMS screens serve as a reasonable indication of whether a firm possesses market power. Failure in either screen creates a rebuttable presumption of market power in generation markets.

If a utility challenges the findings of the market power screens, it can submit additional data using the Delivered Price Test ("DPT") to illustrate that it has not exercised market power. The DPT examines economic capacity and available economic capacity, which is inclusive of all capacity for suppliers with the ability to compete in the market in accordance with the 105% rule. The 105% rule requires the consideration of all supplier capacity into the destination market up to 105% of the current deregulated market price, thereby ignoring bids that drastically exceed the current state of market equilibrium as

30. Id.


32. Id. (noting that the combination of the UMS and UPS market power screens constitute FERC's inquiry into market power in generation. A failure of either screen results in a section 206 proceeding involving market-based rate revocation or denial, in accordance with the Federal Power Act); see also AEP Power Marketing, Inc., 107 F.E.R.C. ¶ 61,018 at PP 200–01 (2004), order on reh'g, 108 F.E.R.C. ¶ 61,026 (2004).

33. ICF Market Power, supra note 14.

34. Id. (stating that entities who fail the market-power screens for generation may rebut the presumption of market power using the delivered price test, which is a broader inquiry that often decreases the chance of finding market power). See also Antitrust Report, supra note 15, at 529 n.75 (citing Duane Morris LLP, Electric Highlights, ENERGY INSIGHTS, Apr. 16, 2004, at 4) (noting that "The Delivered Price Test 'defines the relevant market by identifying potential suppliers based on market prices, input costs, and transmission availability, and calculates each supplier's economic capacity and available economic capacity for each season and load condition.'").

35. The use of economic capacity rather than installed capacity—previously used in the "hub-and-spoke" approach—allows the FERC to narrow the number of suppliers that are said to compete in a given electric market, which increases the chance that the FERC will find that market power exists. See Roach, supra note 22, at 54. "Power plant capacity is considered to be economic capacity if: (a) it can physically be delivered—i.e. there is sufficient transmission capacity to deliver the power to the (hub) market; and (b) it is price competitive—i.e. the capacity can produce and deliver power at a variable cost no greater than 5% above the current market price." Id.

36. "An electric power supplier's available economic capacity is the capacity that remains after native load requirements and firm contractual commitments are subtracted. Essentially, this is the amount of capacity that can produce energy at a competitive cost and is available to compete in the short-term energy market (or short-term capacity market)." Stephen Paul Mahinka & Theodore A. Gebhard, Deregulation and Industry Restructuring: Antitrust Issues in Electric Utility Mergers and Alliances, 12 ANTITRUST 38, 42 (1998).

these bids will not likely be accepted in the absence of collusion.\textsuperscript{38} If FERC remains steadfast in its determination of market power after the DPT, then FERC requires utilities to adopt market-mitigation strategies or risk market-based rate revocation.\textsuperscript{39}

FERC applies a similar market power assessment to transmission markets.\textsuperscript{40} Despite the obvious complexity of the new market power screens, FERC requires that competitors, or those directly affected by the potential market power abuse, initiate the investigation via a complaint to FERC. This indirect investigatory process subjects reporters to the possibility of retribution by the firm allegedly exercising market power.\textsuperscript{41} Such indirect investigatory processes characterize FERC’s refusal to be proactive in maintaining competitive markets and marks its usual position of “fixing only what is broke.”\textsuperscript{42}

Once FERC has determined that a firm has amassed market power, the firm is subject to market-based rate revocation.\textsuperscript{43} For

\textsuperscript{38} Id.


\textsuperscript{40} Id.

\textsuperscript{41} For example, a firm exercising market power may constrain transmission lines in markets not utilizing locational marginal pricing upon discerning the reporter’s identity. This act will interfere with the reporter’s ability to move power from point A to point B in an effort to meet contractual obligations. Without an injunction, the firm may engage in this activity while the investigation by FERC occurs, and the reporter, subsequently, runs the risk of exiting the market. FERC typically moves slowly through the investigation process and increases the risk that a firm reporting the abuse can no longer compete in the market. This is just one example of a gaming strategy that a firm with market power may engage in to punish a firm for filing a complaint with FERC for market power abuse. See generally Narasimha Rao & Richard Tabors, Transmission Markets: Stretching the Rules for Fun and Profit, \textit{The Electricity Journal}, Vol. 13, p. 20 (June 2000) (on file with the author).

\textsuperscript{42} See Pat Wood III, et al., Perspectives from Policymakers, in \textit{Electricity Deregulation} 415, 418 (James M. Griffin & Steven L. Puller eds., 2005). The “fixing only what is broke” language is notable given that it describes how FERC plays an essentially passive role in regulating electricity markets when it may be best for FERC to take a more aggressive stance in rectifying market power abuses.

\textsuperscript{43} The FERC rarely exercises its authority to revoke an electricity supplier’s market-based rates. However, the FERC revoked Enron Power Marketing’s market-based rates in 2003. News Release, Fed. Energy Regulatory Comm’n, Commission Revokes Enron’s Market-Based Rate Authority, Blanket Gas Certificates Terminated (June 25, 2003), available at http://www.ferc.gov/press-room/press-releases/2003/2003-2/06-25-03_enron.pdf (noting that “[r]evocation of market-based rate authority does not necessarily halt a company’s participation in wholesale power markets or bilateral contracts. However, its returns are limited by set cost-of-service tariffs and rates and it
example, in the six months preceding June 30, 2005, FERC notified several energy companies that they were subject to market-based rate revocation after determining they failed the market power screens.\textsuperscript{44} American Electric Power and Dominion Virginia Power within the PJM Interconnect,\textsuperscript{45} South Carolina Gas and Electric,\textsuperscript{46} Tucson Electric Power,\textsuperscript{47} and Aquila Energy\textsuperscript{48} are among the energy companies deemed to have failed the market-power test and are subject to market-based rate revocation. As of June 20, 2005, FERC is investigating Southern Company,\textsuperscript{49} Entergy,\textsuperscript{50} Duke Power,\textsuperscript{51} and Oklahoma Gas and Electric for amassing market power.\textsuperscript{52} FERC’s chief concern is the efficient functioning of competitive energy markets.\textsuperscript{53} The Commission seeks to prevent public utilities from capitalizing on loopholes associated with the ambiguities in reporting status changes required by Order 652.\textsuperscript{54}

\textsuperscript{44} Platts Online, Megawatt Daily: FERC restricts regulation-service bids in new PJM regions; finds market is not competitive (May 9, 2005) (by subscription only; on file with author).

\textsuperscript{45} Id. The PJM Interconnect is a regional transmission organization (“RTO”) that ensures the reliability of electricity flowing in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM, Working to Perfect the Flow of Energy, http://www.pjm.com/index.jsp (last visited Nov. 9, 2006). PJM operates the largest competitive wholesale electricity market in the world. Id.

\textsuperscript{46} Platts Online, Megawatt Daily: FERC delays market power action on 3 firms (June 16, 2005) (by subscription only; on file with author) [hereinafter FERC Delays].

\textsuperscript{47} Platts Online, Megawatt Daily: FERC: TEP, Aquila fail market power screens (Apr. 14, 2005) (by subscription only; on file with author).

\textsuperscript{48} Id.

\textsuperscript{49} FERC Delays, supra note 46.

\textsuperscript{50} Id.

\textsuperscript{51} Id.

\textsuperscript{52} Platts Online, Megawatt Daily: FERC to probe OG&E market power (June 9, 2005) (by subscription only; on file with author).


\textsuperscript{54} See generally FERC Rehearing, supra note 3. If a utility fails both the UPS and UMS market power screens, FERC may revoke market-based rate authority and institute cost-based rates for all geographic markets that the utility possesses market power. Rodgers, supra note 31. As a last resort, the utility may propose other mitigation strategies, such as divestiture or regional transmission organization (“RTO”) or independent system operator (“ISO”) membership, to retain market-based rate authority. Id. FERC has a marked preference for utilizing mitigation strategies other than market-
II. THE EVOLUTION OF THE REPORTING REQUIREMENTS FOR MARKET-BASED RATE SELLERS

FERC requires market-based rate sellers to report any status changes that would reflect a departure from the original characteristics that the Commission relied on in determining market-based rate authority. Traditionally, market-based rate sellers had the option of choosing between reporting the status change when it occurred, filing a three-year update, or reporting changes in combination with updated market analyses.55 These options created incentives for public utilities to choose the three-year update to report status changes to FERC. A public utility could increase profits through delayed reporting of increases in generation capacity that would constitute a status change while potentially subjecting consumers to the exercise of market power. Reports at the time of the status change allow FERC to initiate quickly a market power analysis, decreasing the amount of time the public utility could capitalize on the increased capacity at the expense of consumers. As a result, incentives exist for public utilities to delay reporting status changes (i.e. utilities do not have incentives to immediately report a status change to FERC) via the three-year update, or simply argue that the order is ambiguous and seek a hearing, which further delays action in order to obtain increased market share.

Recognizing the need for reporting a status change more quickly and acting in accordance with section 206 of the Federal Power Act (“FPA”), FERC modified previous standards for market-based rate authority by requiring those who currently had market-based rate authority to report changes in status that would reflect a “departure from the characteristics the Commission originally relied upon in determining market-based rate authority” within thirty days of the occurrence.56


56. FERC Rehearing, supra note 3. In Order 652, The Edison Electric Institute (“EEI”) noted that a market-based rate “applicant should not be required to report a change in circumstances based on an action taken by a competitor (such as a decision to retire a generation unit or take transmission capacity out of service) or natural events (such as a high hydro-year, higher wind generation or load disruptions due to adverse weather conditions) that might change the result of the interim screens.” Order 652, supra note 1, at ¶ 23. The FERC agreed with EEI and now does not require an applicant
FERC also incorporated the thirty-day reporting requirement into the market-based tariff of each public utility. On February 10, 2005, FERC promulgated Order 652, which created uniform standards for status reporting by market-based rate sellers and eliminated the three-year reporting option. Order 652 included a change in the “control” of generation or transmission facilities as a reportable status change; provided information as to the “characteristics” FERC uses in determining market power and market-based rate authority; provided guidance as to the form, timing, and content of the status report; and incorporated the newly promulgated standards into all market-based tariffs. In response, Constellation, EEI, and Reliant Energy made requests for a rehearing and clarification of Order 652.

III. FERC CLARIFICATIONS OF ORDER 652

In the rehearing and clarification proceeding, the Commission determined that Order 652 did not impose additional burdens on market-based rate sellers. FERC clarified that a status report should consist of a transmittal letter describing the status change and whether or not the change constitutes a “departure from the characteristics that the Commission relied upon in originally granting market-based rate authority.” In addition, the Commission determined that changes in status already considered in the application for to report a change in circumstance based on actions taken by competitors or natural events. Requiring applicants to report actions taken by competitors would serve to encourage gaming behaviors by competitors whereby competitors would have incentives to take electricity off-line to enhance a competitor’s market power and subject the competitor to market-based rate revocation or possible divestiture of generation or transmission assets to mitigate the finding of market power. While it is understandable why market-based rate applicants should not have to report actions taken by competitors given the potential for strategic gaming, the FERC does not have the ability to monitor closely electricity markets. Therefore, the FERC heavily relies upon utilities and competitors to self-report anticompetitive behaviors, which often leads to an inaccurate portrayal of the market in question. For example, a competitor may retire generation assets that ultimately serve to increase a competitor’s market power. The FERC does not impose any obligations on the market-based rate seller to report the increase in market power. Consumers are, then, subjected to the market-based rate seller’s market power until a competitor files a complaint to commence a new market power assessment or the market-based rate seller engages in actions that would trigger the reporting requirements.

57. FERC Rehearing, supra note 3, at ¶ 3.
58. Order 652, supra note 1.
59. Id.
60. FERC Rehearing, supra note 3, at ¶ 5.
61. Id.
62. Id. at ¶ 3.
market-based rate authority or in triennial reviews need not be reported. The Commission will allow a market-based rate seller to incorporate any filings regarding the change in status pursuant to other reporting requirements within the notice of the status change. Furthermore, the Commission established a cumulative threshold of 100 MWh for generation increases that are subject to the reporting requirements. In order to alleviate ambiguities, the Commission provided examples whereby the testing of new generation facilities, cumulative increases of generation in excess of 100 MWh, or acquisitions of ownership or control of storage or intrastate natural gas facilities are all subject to the newly promulgated reporting requirements.

A. Exemptions to the Reporting Requirements

Contracts for fixed quantities of delivered energy that do not confer control are not subject to reporting. However, FERC will not exempt generally all contracts for fixed quantities of delivered energy because they possibly could confer control to buyers. EEI sought clarification with regard to construction contracts for which the Commission found that reporting is not necessary until test power is generated and exceeds the 100 MWh threshold. Order 652 requires that utilities report actual status changes to FERC within thirty days. New facilities are not subject to the thirty-day time frame until the plant becomes operational. Expansions of transmission facilities that increase total transmission capacity are subject to reporting, unless the increases are solely due to the public utility’s upgrade of its own network or the construction of new facilities. FERC requires the reporting of transmission facility expansions attributable to a transfer of control or ownership of a third party’s transmission facilities as a status change.

63. Id. at ¶ 9.
64. Id.
65. Id. at ¶ 10.
66. FERC Rehearing, supra note 3, at ¶ 10.
67. Id. at ¶ 12 (noting that FERC simply defined control as “when an entity controls the decision-making process as to how, when, and to whom power is sold or generated by the facilities in question”). Therefore, contracts that do not confer such decision-making authority are not subject to the reporting requirements. See id.
68. Id.
69. Id.
70. Id.
71. Id.
72. FERC Rehearing, supra note 3, at ¶ 12.
B. Ambiguities Associated with “Control” in Order 652

Order 652’s definition of “control” created much consternation and is a focal point of the clarification requests of Constellation and EEI. The Commission found that “control” determinations are fact-specific and complex. However, the Commission affirmed Order 652’s definition of “control” that refers to the granting of control of generation or transmission facilities through contracts or arrangements for the conveyance of ownership. FERC emphasized that control exists when an entity controls the decision-making process as to how, when, and to whom power is sold or generated by the facilities in question, which is consistent with the Commission’s ruling in El Paso Electric and the recently promulgated Order 652. Contractual arrangements with an agent or broker are not transfers of control within the context of the status change reporting requirements, so long as the agent or broker does not retain control or affect the transfer of the capacity to relevant product markets. As contractual arrangements become more complex, the Commission will monitor these agreements and take action as new information is gathered.

C. Contractual Arrangements Subject to Reporting

To reduce the risk of overlooking reportable arrangements, the Commission refused to acquiesce to Reliant Energy’s request

73. *Id.* at ¶ 16.
74. *Id.* FERC refused to further clarify the definition of control, but merely stated that what constitutes control is fact-specific and depends on the terms and conditions of the contract in question. *Id.*; see also Van Ness & Feldman, *FERC Clarifies Rule on Reporting of Changes in Status by Sellers of Electricity at Market-Based Rates* (June 23, 2005), http://www.vnf.com/content/alerts/alert062305.htm.
75. *Id.* at ¶ 17; see also El Paso Elec. Co., 108 F.E.R.C. ¶ 61,071 (July 22, 2004) (noting the public utilities’ attempt to persuade the Commission that the “quantum of control” definition should be broad, which implies a lesser standard of control when assessing market power). In Order 652, FERC rejects the argument that “quantum of control” is broad and implies a lesser standard for assessing control in market power determinations. *Order 652, supra note 1, at ¶ 17.* The definition of control remains a controversial aspect of FERC regulation. Courts and regulators routinely fail to “comprehend the tenuousness of one’s ability to actually control and confine electricity. Tracking exactly where any individual electron travels is impossible. . . electricity is a force, like the wind, with the potential to do work.” Steven Ferrey, *Inverting Choice of Law in the Wired Universe: Thermodynamics, Mass, and Energy*, 45 Wm. & Mary L. Rev. 1839, 1882 (2004). Furthermore, the use of control as a benchmark physical description of electricity serves to undermine the characterization of electricity as a product that is created and controlled until use and consumption. *Id.*
76. *Id.* at ¶ 18.
77. *Id.* at ¶ 19.
for a list of reportable contracts or arrangements. The Commission did, however, address concerns about fuel capacity credits. If control is not transferred to the purchaser, capacity credits are not deemed reportable. Order 652 generally requires that contractual agreements with durations of one year or more be reported to the Commission. Master agreements with several subordinate agreements must be treated as one agreement for purposes of determining the duration of the agreement. The duration of the agreement is the maximum period contemplated by the agreement. If the duration is unspecified or indefinite, the default rule deems that the master agreement duration exceeds one year and is subject to the reporting requirements of Order 652. Fuel supply arrangements intended to transfer control of jurisdictional assets constitute a reportable status change. FERC characterizes jurisdictional assets as assets that are subject to Commission oversight in accordance with section 203 of the Federal Power Act. Furthermore, the Commission desires to narrow the definition of inputs to electric power production to make market power assessments less complicated, which increases regulatory efficiency.

**D. The Netting Approach & The Reporting of Affiliate Relationships**

The Commission adopted a netting approach whereby market-based rate sellers can offset decreases in generation or transmission capacity against increases in generation or transmission capacity. It remains unclear if increases in generation or transmission capacity have to occur simultaneously with decreases in such capacity to avoid the FERC’s reporting requirements. Neither Order 652 nor the rehearing specifically

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79. *Id.*
80. *Id.* at ¶ 21.
81. *Id.*; see also Clarksdale Pub. Util. Comm’n, 85 F.E.R.C. ¶ 61,268, at 62,078–79 (Nov. 24, 1998) (stating that the actual length of the transaction, not the number of agreements, should be used to determine if the contract exceeds one year in duration and is subject to reporting requirements).
82. *FERC Rehearing*, supra note 3, at ¶ 21.
83. *Order 652*, supra note 1, at 10–11.
84. *Id.*; see also Conference on Supply Margin Assessment, 108 F.E.R.C. ¶ 61,026 (July 8, 2004).
86. *Id.*
addressed an allowable time frame for the netting approach.\textsuperscript{88} The newly adopted netting approach, however, remains subject to the cumulative 100 MWh threshold, meaning that the net change in assets cannot exceed 100 MWh.\textsuperscript{89}

Under Order 652, market-based rate sellers must timely report ownership or control changes in generation or transmission facilities, or changes in inputs to electric power production, except fuel supplies.\textsuperscript{80} In addition, market-based rate sellers shall disclose any affiliations that cause a status change not disclosed in the original market-based rate authority determination within thirty days of the legal transfer of control.\textsuperscript{91} The reporting of status changes associated with affiliations serves to mitigate issues involving reciprocal dealing and affiliate abuse to obtain market power. The reporting requirement for status changes associated with affiliation changes subjects consumers to the utility’s potential market power for thirty days, which may serve to force competitors out of the market or lead to price increases. FERC should consider premising legal transfer of control of the affiliate’s assets to the acquiring utility on an immediate market-power assessment, whereby the utility must report the status change and pass the market-power screens prior to the legal transfer of control.

E. Reporting Obligations for Status Changes That Occurred Before Order 652 & Natural Gas Reporting Requirements

Status changes that occurred before the enactment of Order 652 are not subject to the thirty-day reporting requirement.\textsuperscript{92} The Commission also allows for corporate family affiliates to file a single notice of status change that lists each affiliate company holding market-based rate authority.\textsuperscript{93} If the date in which control is transferred occurs before the date in which the purchaser is to commence physical delivery of power, then the reporting obligation is unnecessary.\textsuperscript{94} The Commission encourages parties to file reports of prospective status changes in order to expedite investigations in a timely and efficient

\textsuperscript{88} See FERC Rehearing, supra note 3. See also Order 652, supra note 1.

\textsuperscript{89} FERC Rehearing, supra note 3, at ¶ 25 (noting that the 100 MWh threshold was originally created in Order 652).

\textsuperscript{90} Id. at ¶ 27.

\textsuperscript{91} Id.

\textsuperscript{92} Id. at ¶ 30.

\textsuperscript{93} Id. at ¶ 32.

\textsuperscript{94} FERC Rehearing, supra note 3, at ¶ 33.
manner. The Commission, however, did not mandate reports for all prospective status changes.

Furthermore, with regard to natural gas pipelines, mere acquisition of pipeline capacity owned or controlled by a non-affiliated entity is not subject to the reporting requirement. Affiliations with interstate natural gas pipelines do not automatically raise market power concerns because the pipelines are subject to open access requirements much like transmission facilities in the electric power industry.

IV. INFORMATIONAL ASYMMETRIES AND MARKET FAILURES PERPETUATED BY THE REVISED REPORTING REQUIREMENTS

In promulgating Order 652, the Commission sought to provide a uniform system of reporting status changes to prevent utilities from amassing market power. In an attempt to further clarify the reporting requirements, the Commission, in the rehearing, delineated examples subject to reporting and solidified many definitions codified in Order 652. The process that FERC utilizes to investigate market abuses is reactive. For example, section 205 of the Federal Power Act affords a utility the right to file rates and terms for services rendered with its assets. However, courts have routinely found that FERC plays “an essentially passive and reactive role under Section 205.”

FERC continually has adopted a piecemeal process for regulating energy markets, which Pat Wood III, former Chairman of FERC, characterized as “fixing only what is broke.” The deregulation of electricity markets mirrors that of natural gas markets, for in both instances FERC’s regulatory presence is reactive.

95. Id.
96. Id. at ¶ 33. Natural gas reporting requirements are of interest to public utilities serving the electric needs of customers because many utilities own generation fueled by natural gas. Senator James M. Inhofe & Frank Fannon, Energy and the Environment: The Future of Natural Gas in America, 26 ENERGY L. J. 349, 350 (2005) (noting that natural gas comprises twenty-four percent of U.S. energy use with most of the natural gas used to supply electricity generation and that experts project that natural- gas-fired electricity generation will double in the next decade). Therefore, public utilities desire an uninterrupted flow of natural gas to supply their electric generation. See id. at 351–52.
97. FERC Rehearing, supra note 3, at ¶ 35.
99. Wood, supra note 42.
The Natural Gas Policy Act ("NGPA"), enacted in 1978, initiated the process of natural gas deregulation by attempting to create a single natural gas market spanning the entire nation, achieving equilibrium of supply and demand, and allowing market forces to create wellhead prices.\textsuperscript{101} The NGPA also marked the creation of the Federal Energy Regulatory Commission, which was given the authority to regulate natural gas markets except for imports and exports (which was entrusted to the newly created United States Department of Energy).\textsuperscript{102} While the NGPA marked the commencement of competitive natural gas markets, extensive regulations remained in the sale of natural gas to local utilities and local distribution companies.

Seven years later, FERC promulgated Order 436, which initiated the first stage for open access of pipelines.\textsuperscript{103} Because adding to the infrastructure of pipelines to create competition is costly and acts as a substantial barrier to entry, open access to pipelines was necessary so that capacity could be bought in the pipeline on a non-discriminatory basis.\textsuperscript{104} Order 636, promulgated in 1992, completed the institution of open access of natural gas pipelines.\textsuperscript{105} Order 636 forced the unbundling of jurisdiction over transmission of natural gas through pipelines was eventually ceded to federal administrative agencies. Natural Gas Act of 1938, 15 U.S.C. § 717 (2005) (allocating to the Federal Power Commission the authority to regulate rates charged for interstate natural gas delivery); see also Joseph Fagan, From Regulation to Deregulation: The Diminishing Role of the Small Consumer Within the Natural Gas Industry, 29 \textit{Tulsa L. J.} 707, 711–12 (1994). In the context of pricing, the Federal Power Commission ("FPC"), a federal administrative agency and FERC's predecessor, regularly utilized a cost-of-service rate plan to regulate wellhead prices. Bradley W. Maudlin, \textit{Oil and Gas Law: State Production Regulation Under the Natural Gas Act Revisited Northwest Central Pipeline Corp. v. State Corporation Commission}, 109 S.Ct. 1262 (1989), 29 \textit{Washburn L. J.} 123, 132 (1989). As observed in most price-control schemes, supply shortages resulted and surging demand, fueled by the OPEC Crisis of the early 1970s, only exacerbated the flaws associated with the pricing scheme. Id. The FPC realized, reactively, that something must be done to alleviate the natural gas supply shortages. In a delayed response, the FPC urged Congress to enact the Natural Gas Policy Act of 1978. Id.; see also Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301–3432 (1989).

101. Wellhead prices are "what it costs to produce natural gas at the wellhead. The wellhead price does not include any charges for treating, gathering, processing, transporting, or distributing." FERC: Glossary, http://www.ferc.gov/help/glossary.asp#W (last visited Sept. 12, 2006).


105. Id. at 20–21 (construing Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations and Regulation of Natural Gas Pipelines after Partial
pipeline services that was only voluntary under Order 436.106 Order 636 requires pipelines separate their transportation and sales services so that all pipeline customers have a choice in selecting their gas sales, transportation, and storage services from any provider, in any quantity.107 This marked the culmination of deregulation of natural gas markets.108

Today, consumers still do not reap the benefits of a fully deregulated natural gas market due to the failure of the states and FERC to require the unbundling of local distribution companies (“LDCs”).109 Since the enactment of the NGPA, it has taken twenty-eight years for the regulators to only partially open natural gas markets to competition. A similar time lag has occurred in electricity markets due to a failure to be proactive in designing markets and enforcing competition standards. As evidenced by the twenty-eight year time frame to only partially deregulate natural gas and electricity markets, FERC regularly participates in a process whereby a problem is diagnosed, often several years later, and a quick fix is issued.110 However, a significant amount of time usually elapses before the quick fix is issued. The methods used by FERC serve to elongate the deregulation process, but FERC often lacks the resources


106. Id.
107. Id.
108. Id. at 21.

necessary to properly monitor markets. Therefore, it is helpful to chart the deregulatory process in both natural gas and electricity markets to illustrate how FERC is unable to be proactive in either market due to budgetary constraints.

Various governmental agencies, namely the Securities and Exchange Commission ("SEC"), take more aggressive actions in rooting out behavior that is detrimental to functioning competitive markets. Although abuses occur in financial markets, the SEC takes numerous steps to rectify such abuses and gather information through various reporting requirements and investigations with the goal of preventing further market failures.

FERC, however, does not take such a proactive approach to rectify market failures. FERC instead relies on self-reporting of public utilities and other energy market participants. In August 2003, a General Accounting Office ("GAO") study of the Office of Market Oversight and Investigations ("OMOI"), the energy market oversight branch of FERC, found that fourteen percent of FERC’s staff was employed by the agency for one year or less. The GAO study also determined that only fifty-three percent of FERC’s employees believed that OMOI had established effective processes to oversee markets. Given the findings of the GAO study, it appears that FERC lacks the experienced personnel and processes needed to monitor adequately and proactively energy markets.

FERC is attempting to take a more proactive approach via the newly enacted status-reporting requirements. The new reporting requirements, and the subsequent clarifications, do serve to reduce transaction costs through the dissemination of information, thus improving market transparency. However, the
reporting requirements do not go far enough and they continue to be somewhat ambiguous. FERC requires the reporting of all status changes, yet only recommends the reporting of proposed status changes in generation or transmission capacity. The reporting of proposed status changes would be proactive in nature and would possibly serve to mitigate some of the market power issues previously mentioned. For example, the SEC requires extensive reporting of proposed mergers, acquisitions, initial public offerings, and other financial transactions; which allows the agency to take a proactive approach\(^\text{115}\) and investigate before the activity begins.\(^\text{116}\) FERC investigations occur after the commencement of the anticompetitive activity. The delayed investigation exposes market participants to the potentially anticompetitive behaviors of the alleged “evil-doers” for an extended period of time. FERC may be able to diagnose appropriately and rectify anticompetitive behavior, yet the damage to the competitive energy market has already been done and often may not be reversed.

In addition, ambiguities arise as to the newly adopted netting program. The clarifications of Order 652 do not provide guidance as to the time frame in which increases and decreases in generation capacity may be netted out. It remains unclear whether the increases and decreases in generation capacity have to occur simultaneously, or in some sort of abbreviated time frame, in order to trigger the netting program.

Ambiguous requirements create incentives for public utilities to delay reporting status changes, request hearings before the Commission to clarify definitions to further the delay in reporting, or neglect reporting altogether. Either way, potentially burdensome transaction costs are imposed on the deregulated market. Failure to report, or delayed reporting, prevents the Commission from investigating and rectifying the amassing of market power, which harms power markets through reduced competition. However, the Commission continually relies upon the public utilities to essentially self-govern themselves and


creates incentives for utilities to report misleading
information. For example, once the initial application for
market-based rates is completed, further inquiries as to the
propriety of market-based rate authority typically only
commence upon a complaint filed by a competitor or interested
party. Self-reports are occasionally the basis for a FERC
investigation, but FERC’s rules essentially allow self-governance
by creating incentives to report misleading information. Given
the Enron debacle of recent years, consumers and regulatory
bodies do not trust energy market participants to report
accurately and timely status changes to the Commission that
could result in a reduction of profits via a revocation of market-
based rate authority.

V. CONCLUSION

FERC’s increased reporting requirements are a step in the
right direction, but more intervention is needed. Structural
uniformity in electricity markets is desirable to help ensure market transparency. FERC must restructure and imitate the proactive behaviors of the SEC. Competition and market transparency would be aided through required reporting of proposed status changes, much like that of mergers or acquisitions. Market transparency can be achieved through more stringent reporting requirements, thus alleviating information asymmetries. However, further rehearings and clarifications are inevitable given the complex nature of the industry and the ambiguities associated with current FERC regulations. FERC must also further clarify the parameters of the netting program. Finally, with regard to market-based rate authority, FERC should be more conservative in the authorization of market-based rates and actively use market-based rate revocation to punish those who delay or fraudulently report status changes or report misleading information that undermines market transparency. The goal of these policies is to align incentives so that public utilities provide the Commission with appropriate information to maintain competition and thus benefit all those participating in energy markets.

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