REPORT OF THE ANTITRUST COMMITTEE

This report summarizes antitrust developments of particular interest to energy law practitioners that occurred in the year 2006.* The topics are covered in the following order:

I. MERGER REVIEW

A. Exelon Corporation and Public Service Enterprise Group

In June 2006, the U.S. Department of Justice (DOJ) required Exelon Corporation (Exelon) and Public Service Enterprise Group (PSEG) to divest six electric generation plants—two in Pennsylvania and four in New Jersey—in order to proceed with their proposed merger. Although Exelon and PSEG subsequently obtained the Federal Energy Regulatory Commission's (FERC) approval of their proposed merger, they later abandoned the merger when they were unable to obtain the approval of state regulators in New Jersey, pointing

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out the increasingly important role of the states in the utility merger process. Nevertheless, the DOJ's competitive analysis in support of the proposed settlement provides guidance for future mergers involving electric generation assets.

The DOJ's complaint focused on horizontal competitive concerns in the wholesale electricity product market and in the PJM East and PJM Central/East geographic markets.[1] PJM East includes the densely populated northern New Jersey and Philadelphia areas, while PJM Central/East includes PJM East, central Pennsylvania, and eastern Maryland. Transmission constraints sometimes isolate these areas from the rest of the PJM control area.

According to the DOJ, the merger would have created one of the largest electricity companies in the U.S. and combined two of the largest electric generation competitors in the mid-Atlantic region, with a total generating capacity of more than 40,000 megawatts (MWs). The merged company would have owned approximately forty-nine percent of the electric generation capacity in PJM East, and approximately forty percent of the electric generation capacity in PJM Central/East. Thus, the merger yielded a post-merger HHI in PJM East of approximately 2,750 points, representing an increase of more than 1,100 points, and a post-merger HHI in PJM Central/East of approximately 2,080 points, an increase of approximately 790 points. The DOJ also alleged that the merger would have enhanced the incentive and ability of the merged firm to raise wholesale electric prices by withholding selected capacity in the relevant areas. In addition, the DOJ concluded that entry through the construction of new generation or transmission capacity would not be timely, likely, and sufficient to deter or counteract an anticompetitive price increase.

Under the terms of the proposed consent decree, the companies were required to divest six generation plants, with more than 5,600 MW of generating capacity.[2] The DOJ selected plants that it believed would reduce the merged firm's ability and incentive to withhold capacity and raise prices. The plants to be divested were the Cromby Generating Station and Eddystone Generating Station in Pennsylvania, and the Hudson Generating Station, Linden Generating Station, Mercer Generating Station, and Sewaren Generating Station in New Jersey. Divestiture would have reduced the merged firm's share of generating capacity to thirty-two percent in PJM East and twenty-nine percent in PJM Central/East. The DOJ also required the merged company to obtain DOJ approval prior to acquiring or obtaining control of any existing generation plants in the mid-Atlantic region in the future.

B. In the Matter of Dan L. Duncan, EPCO, Inc., Texas Eastern Products Pipeline Co., LLC, and TEPPCO Partners, L.P.

In August 2006, the Federal Trade Commission (FTC) challenged a 2005 acquisition that combined the natural gas liquids (NGLs) storage businesses of Enterprise Product Partners, L.P. (Enterprise) and TEPPCO Partners, L.P.

1. Complaint, United States v. Exelon Corp., No. 1:06CV01138 (D.D.C. June 22, 2006), *available at*: http://ww.usdoj.gov/atr/cases/f216785.htm.

2. The proposed final judgment is *available at* http://www.usdoj.gov/atr/cases/f216700/216784.htm (last visited Feb. 22, 2007).

(TEPPCO) under common ownership.[3] As a result of the acquisition, both the Enterprise and TEPPCO NGL storage businesses were ultimately owned and controlled by Mr. Dan L. Duncan. The FTC alleged that the transaction would reduce the number of commercial salt dome NGL storage providers in Mont Belvieu, Texas, from four to three, resulting in higher prices and degradation of service. To settle the case, the FTC required the parties to "unscramble the egg" by selling an NGL storage facility and associated assets to an FTC-approved buyer by December 31, 2006.[4]

The acquisition at issue occurred in February 2005, when EPCO, Inc. (EPCO) acquired control of TEPPCO. The acquisition was not required to be reported under the Hart-Scott-Rodino Act. According to the FTC, Enterprise, a wholly-owned subsidiary of EPCO, and TEPPCO operate the two leading providers of NGL salt dome storage out of the four providers in the Mont Belvieu market, and also own and control other related assets including substantial NGL pipeline transportation capacity into and out of Mont Belvieu. NGLs—including ethane, propane, normal butane, isobutene, and natural gasoline—are used in a variety of ways, including as feedstocks in the production of ethylene and propylene, as fuel for heating or industrial processes, and in blending components for gasoline. NGLs are primarily stored in large underground wells formed out of geological salt domes until delivered to end users, primarily through pipelines. The FTC found that even though Enterprise and TEPPCO maintained separate management teams, the acquisition gave Duncan practical control of both entities and consequently of the majority of NGL storage capacity in Mont Belvieu, the largest NGL storage system in the world.

The FTC alleged that the market for salt dome NGL storage in Mont Belvieu was highly concentrated, with Enterprise and TEPPCO being the two largest suppliers based on volumes of NGLs stored, with a combined market share of approximately seventy percent. According to the FTC, the acquisition gave Duncan control over a dominant share of NGL storage volumes and capacity. Pre-acquisition, Enterprise and TEPPCO competed for NGL volumes in Mont Belvieu based on price and service levels, with many NGL customers ranking them as their first and second choice for NGL storage. The FTC alleged the acquisition would enhance the ability of Enterprise/TEPPCO to exercise market power, and increase the likelihood of coordinated interaction among competitors. In addition, the FTC asserted that the remaining two NGL suppliers could not replace the competition lost through the acquisition, leading to higher prices and reduced service for NGL storage customers. According to the FTC, entry into the Mont Belvieu NGL salt dome storage facility market would not be likely, timely, or sufficient to offset the anticompetitive effects of the acquisition.

3. Complaint, *In re* Duncan, No. C-4173 (FTC), *available at* http://www.ftc.gov/os/caselist/0510108/complaint.pdf.

4. Consent Order, *In re* Duncan, No. 051-0108 (FTC), *available at* http://www.ftc.gov/os/caselist/0510108/agreement.pdf. The FTC's Decision and Order are available at http://www.ftc.gov/os/caselist/0510108/decisionorder.pdf.

To remedy the competitive harm resulting from the acquisition, the FTC required TEPPCO, and Duncan in particular, to divest the ownership interest in the Mont Belvieu Storage Partners NGL salt dome facility, and related pipeline facilities and other assets by December 31, 2006. To help ensure that Duncan cannot adversely affect competition in the market in the future, the FTC further required Duncan to provide prior notice before acquiring, operating, or managing any NGL storage facility in Mont Belvieu in the next ten years, and required him to send the FTC copies of any new NGL storage leases with third-party NGL storage facilities in Mont Belvieu within fifteen days of when they are signed or become effective. The FTC also imposed several conditions on the divestiture intended to ensure that the acquirer of the divested assets maintains the competitive viability of the divested facility and receives the resources necessary to be a viable competitor.

C. KeySpan and National Grid

In October 2006, the FERC approved the merger of KeySpan Corp. and London, U.K.-based National Grid.[5] The FERC reviewed the proposed merger under the expanded merger review authority granted by the Energy Policy Act of 2005 (EPAct 2005).[6]

National Grid owns and operates electric transmission facilities and distributes electricity and natural gas in New York State, and owns and operates electric transmission facilities in New England. KeySpan provides electric utility and non-utility services in the Northeast U.S., primarily in the New York and Long Island region. KeySpan is also the largest natural gas distributor in the Northeast U.S.

The FERC found that "the combination of [the companies'] electric generation resources is not likely to harm competition in any relevant . . . market," and will not adversely affect wholesale power rates. With regard to potential horizontal competitive effects, the FERC found little overlap between KeySpan's generating resources located in New York City and Long Island and National Grid's limited generating resources in upstate New York and New England.[7] In addition, National Grid has been, and likely will continue to be, a significant provider of last resort obligations, and all of its electric generation resources are dedicated to serving those obligations. As a result, National Grid will have no available capacity that would increase market concentration in any relevant market, according to the FERC. Similarly, most of KeySpan's generation is committed under long-term contracts to the Long Island Power Authority. The FERC also noted the companies' commitments: (a) not to make bilateral sales from upstate New York generating resources into New York City or Long Island without prior FERC approval;[8] and (b) to hold ratepayers harmless from transaction-related costs in excess of transaction-related savings for five years.[9] With regard to potential vertical competitive effects, the FERC

5. *National Grid plc and KeySpan Corp.*, 117 F.E.R.C. ¶ 61,080 (2006) [hereinafter *National Grid*].

6. Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594.

7. *National Grid*, *supra* note 5, at P 26.

8. *Id.* at P 28.

9. *National Grid*, *supra* note 5, at P 54.

also found that the merger was unlikely to have an adverse impact on competition because there is little, if any, vertical competitive overlap between the merging companies' facilities in the relevant markets.[10] To the extent any vertical overlap existed, the FERC found the companies mitigated any competitive concerns by turning over operational control of their electric transmission facilities to the New York Independent System Operator and the ISO New England, thus eliminating any ability for the merged firm to use its electric transmission to harm competition in wholesale electricity markets.[11]

Consistent with its new authority under EPAct 2005, the FERC also found that the applicants provided sufficient assurance that the merger will not result in cross-subsidization of a non-utility company or in the pledge or encumbrance of utility assets for the benefit of an associate company.[12] According to the FERC, in addition to providing the required verifications and other information, the applicants committed that:

> (1) the merger will not change state or [FERC] regulatory oversight of the affected utilities for retail and wholesale services; (2) a Code of Conduct will be implemented for all subsidiaries of the merged company that is similar to National Grid's existing Code of Conduct; (3) the transaction's hold harmless commitment will protect customers from merger-related rate increases for a period of five years following the transaction; and (4) any modification to the National Grid money pool that provides for KeySpan subsidiaries' participation will be subject to [FERC] approval and represent that the merger will not change regulatory oversight of the affected utilities.[13]

Finally, with regard to complaints by intervenors about National Grid's staffing policies and collective bargaining agreements, the FERC found that such matters go beyond the scope of its analysis as set forth in the Merger Policy Statement.[14] The FERC also rejected allegations that a pre-filing meeting with the merging parties was an impermissible *ex parte* communication, ruling that its *ex parte* regulations are not triggered until a merger filing is made and contested.[15]

D. Westar Energy, Inc. and ONEOK Energy Services Co., L.P.

In May 2006, the FERC conditionally approved: (a) the sale from ONEOK Energy Services (ONEOK) to Westar Energy (Westar) of a 300 MW generation plant and associated transmission facilities; and (b) the transfer of a 75 MW wholesale power purchase agreement from ONEOK to Westar, along with associated facilities.[16] The FERC's conditional authorization was premised on mitigation of potential market effects through transmission upgrades.

According to the FERC, the applicants failed to show that the acquisition of the 300 MW Spring Creek generating facility would not adversely affect

10. *Id.* at P 44.
11. *National Grid*, *supra* note 5, at P 45.
12. *Id.* at P 65.
13. *National Grid*, supra note 5, at P 65.
14. *Id.* at P 77.
15. *National Grid*, *supra* note 5, at P 78.
16. *Westar Energy, Inc. and ONEOK Energy Servs. Co., L.P.*, 115 F.E.R.C. ¶ 61,228 (2006) [hereinafter *Westar Energy*].

competition. If Spring Creek were to become a network resource, then the transaction would fail to pass the FERC's Competitive Analysis Screen, requiring transmission upgrades to mitigate any adverse competitive effects.[17]

The FERC specifically found that in the "Winter Super Peak" period (defined as the top ten percent of peak load hours for December, January, and February), that the transaction would give Westar a forty-two percent market share, that the market would be highly concentrated, and that the transaction would further increase market concentration, increasing the post-merger HHI by 381 points. Moreover, the transaction involved a peaking facility, which supplied the electricity needed in the Winter Super Peak period.[18] However, the FERC rejected assertions that Westar's role as marketing agent for the 1,200 MW Redbud generation facility should be considered in performing the delivered price test, finding that Westar lacked control of the facility.[19]

Regarding the issue of mitigation, the FERC noted that under section 203(b) of the Federal Power Act (FPA), it has the authority to impose additional mitigation conditions in the future—after the consummation of the transaction—to ensure that the transaction is consistent with the public interest.[20] Thus, the FERC reserved the right to order additional mitigation in the future if warranted by changed circumstances, such as could occur if Westar decides later to designate the Spring Creek facility as a network resource, resulting in additional market screen failures.[21] The FERC further required Westar to increase transfer capability into the Westar market by 325 MW in order to bring market concentration down to within 100 HHI of the pre-transaction level.[22] In addition, the FERC rejected the applicants' assertion that they should have the mitigation option of generation divestiture instead of transmission upgrades, finding that applicants had failed to offer to divest units that were economically comparable to the Spring Creek facility.[23]

II. FEDERAL TRADE COMMISSION REPORT ON INVESTIGATION OF GASOLINE PRICES

In the summer of 2005, Hurricanes Katrina and Rita hit major portions of the Gulf Coast region, and in the aftermath of those storms, gasoline prices rose substantially throughout the nation. As a result, Congress subsequently enacted two pieces of legislation directing the FTC to investigate gasoline prices. Section 1809 of the EPAct 2005 required the FTC to conduct an investigation to determine if the price of gasoline was being "artificially manipulated by reducing refinery capacity or by any other form of market manipulation or price gouging practices."[24] Section 632 of the FTC's appropriation legislation for

17. *Id.* at P 71.
18. *Westar Energy*, *supra* note 16, at P 72.
19. *Id.* at P 76.
20. *Westar Energy*, *supra* note 16, at P 79.
21. *Id*.
22. *Westar Energy*, *supra* note 16, at P 81.
23. *Id.* at P 82.
24. Energy Policy Act of 2005 § 1809.

2006 directed the FTC to investigate nationwide gasoline prices and possible price gouging in the aftermath of Hurricane Katrina.[25]

The FTC issued its report of that investigation on May 22, 2006.[26] Noting at the outset that the terms "price manipulation" and "price gouging" were not defined legal or economic terms, the FTC defined "price manipulation," for purposes of its report, as "all transactions and practices that are prohibited by the antitrust laws, including the Federal Trade Commission Act," and all other transactions, irrespective of their legality under the antitrust laws, that "tend to increase prices relative to costs and to reduce output."[27] For the definition of "price gouging," the FTC looked to section 632, which directs the FTC to treat as evidence of price gouging any finding that the average price of gasoline available for sale to the public in September 2005 or thereafter exceeded the average price of such gasoline in that area for the month of August 2005, unless the FTC found substantial evidence that the increase was substantially attributable to additional costs in connection with the production, transportation, delivery, and sale of gasoline in that area, or to national or international market trends.[28] The FTC therefore analyzed whether post-Katrina price increases were attributable to either increased costs or national or international trends.[29]

The FTC found no evidence of price manipulation at the refining level[30] or involving access to transportation (pipelines or ships),[31] no evidence that firms made inventory decisions in order to manipulate prices,[32] and "very limited" potential for price squeezes in gasoline futures markets.[33]

The FTC further found no evidence of anticompetitive behavior in national and regional gasoline pricing after the hurricanes.[34] The Gulf Coast plays a critical role in U.S. gasoline supplies, and while the disruptions of refinery and pipeline operations by the hurricanes caused gasoline prices to increase significantly throughout the nation, the FTC found those increases to be consistent with significantly increased marginal costs of supply, and more consistent with a competitive outcome than with anticompetitive behavior or price manipulation.[35]

Turning to the question of "price gouging," the FTC found that a limited number of refiners, non-refining wholesalers, and retailers had engaged in conduct that met the definition of price gouging that the FTC had adopted for purposes of the investigation, because these price increases could not be

25. Science, State, Justice, Commerce, and Related Agencies Appropriations Act, 2006, Pub.L. No. 109-108 § 632, 119 Stat. 2290 (2005).

26. FTC, INVESTIGATION OF GASOLINE PRICE MANIPULATION AND POST-KATRINA GASOLINE PRICE INCREASES (Spring 2006), www.ftc.gov/reports/060518PublicGasolinePriceInvestigationReportFinal.pdf [hereinafter FTC Report].

27. *Id*. at ii.

28. FTC Report, *supra* note 26, at iii.

29. *Id*. at iii.

30. FTC Report, *supra* note 26, at 20.

31. *Id*. at 43.

32. FTC Report, *supra* note 26, at 49.

33. *Id*. at 58.

34. FTC Report, *supra* note 26, at 81.

35. *Id*.

attributed to either increased costs or national or international market trends.[36] The FTC reached that conclusion notwithstanding the fact that such conduct does not currently violate any provision of federal law.[37] In a number of cases, moreover, the increased prices were consistent with, or at least partially explained by, local (as opposed to national or international) market conditions.[38]

Finally, the FTC considered whether to recommend the enactment of a federal price gouging statute. The FTC observed that the challenge in crafting price gouging legislation is the ability to distinguish "gougers" from those who are reacting in an economically rational manner to the temporary shortages resulting from an emergency.[39] It further noted that if price signals were not present or were distorted by legislative or regulatory commands, "markets may not function efficiently and consumers may be worse off." [40] In view of those factors, the FTC declined to recommend federal price gouging legislation, because it could not say that such legislation would produce a net benefit for consumers.[41]

III. ELECTRIC ENERGY MARKET COMPETITION TASK FORCE REPORT

The interagency Electric Energy Market Competition Task Force established by section 1815 of the EPAct 2005[42] published its draft report on June 13, 2006.[43] The Task Force, made up of representatives of the FERC, the DOJ, the FTC, the Department of Energy, and the Department of Agriculture, was constituted by and required under EPAct 2005 to "conduct a study and analysis of competition within the wholesale and retail market for electric energy in the United States" and report its findings to Congress within one year.[44] While the draft report, which the Task Force characterized as its "preliminary observations,"[45] was issued on schedule, no final report has yet been published, nor is there any indication publication is imminent. It appears the Task Force draft may remain a work in progress for some time to come.

Chapter 1 of the draft report provides a detailed description of the electric power industry, including its history through the twentieth century, developments and trends in industry structure and regulation, and the different directions taken in different regions to restructure the industry.[46]

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36. FTC Report, *supra* note 26, at 153-54.

37. *Id*. at 189.

38. FTC Report, *supra* note 26, at 153-54.

39. *Id*. at 183.

40. FTC Report, *supra* note 26, at 196.

41. *Id*.

42. Energy Policy Act of 2005 § 1815.

43. Electric Energy Market Competition Task Force: Notice Requesting Comments on Draft Report to Congress on Competition in the Wholesale and Retail Markets for Electric Energy, 71 Fed. Reg. 34,083 (June 13, 2006) [hereinafter Task Force]. The final report was due to be submitted to Congress by August 8, 2006. To date, no final report has been published, and as of February 1, 2007, the FERC website indicates it is still unfinished.

44. Energy Policy Act of 2005 § 1815(b)(1).

45. Task Force, *supra* note 43, at 34,085.

46. *Id*. at 34,087-34,103.

Chapter 2 sets out the "Context for the Task Force's Study of Competition," comparing and contrasting traditional cost-based rate regulation with competitive market approaches.[47]

Chapter 3 of the draft report addresses wholesale competition and poses the question:

Has competition in wholesale markets for electricity resulted in sufficient generation supply and transmission to provide wholesale customers with the kind of choice that is generally associated with competitive markets?[48]

The draft report admits this question was "challenging to address" because "[r]egional wholesale electric power markets have developed differently since the beginning of widespread wholesale competition."[49] In the Northwest and Southeast, wholesale electric markets are predominantly based on bilateral trades. There is no centralized trading and market-clearing mechanism. By contrast, in the Northeast, Midwest, Texas, and California, various forms of Regional Transmission Organizations (RTO) and Independent System Operators (ISO) operate centralized regional transmission facilities and trading markets.

The draft report points out that both wholesale market paradigms have strengths and weaknesses. In markets dominated by bilateral contracts, lack of transparency can lead to inefficient use of transmission and generation resources. These inefficiencies can make it difficult for wholesale customers to shop for least-cost supply options.[50] On the other hand, while centrally dispatched systems can lead to increased trading efficiency, concerns have been raised in these markets about the inability to obtain long-term transmission access at predictable prices and, as a consequence of this uncertainty, doubts about the ability to attract new investment in transmission and generation.[51]

Most of the wholesale market discussion in the draft report revolves around alternatives for attracting appropriate amounts of new investment in transmission and generation. After a review of the different situations in the Midwest, Southeast, California, New England, New York, mid-Atlantic (PJM), Texas (ERCOT), and the Northwest, the draft report explores the "range of available options."[52] The first discussed is "Open Access Transmission Without an Organized Exchange Market," the current situation in the Southeast and Northwest. While bilateral contracts have advantages (price predictability and roughly correct price signals to attract new generation investment), the model is extremely dependent on the availability of transmission capacity in the long term, as well as confidence that access will be nondiscriminatory.[53]

Next, the draft report considers "Unmitigated Exchange Market Pricing," a centralized energy market where prices rise and fall solely in response to supply and demand.[54] The draft report calls this approach "controversial," apparently

47. Task Force, *supra* note 43, at 34,103-34,106.

48. *Id*.

49. Task Force, *supra* note 43, at 34,103-34,106.

50. *Id*.

51. Task Force, *supra* note 43, at 34,103-34,106.

52. *Id*. at 34,116.

53. Task Force, *supra* note 43, at 34,116.

54. *Id*. at 34,117.

referring to the fact that no one has actually tried it due to the political unpopularity of price spikes. In addition, the draft report points out, it can be difficult to distinguish price spikes caused by genuine supply-demand imbalance from the rent-seeking exercise of market power. However, apart from political and market power issues, unfettered pricing sends appropriate price signals both to investors (who can build new capacity when and where needed) and to consumers (who can modify their behavior and conserve to reduce demand). A real-world version of this approach is covered under the heading "Moderation of Price Volatility With Caps and Capacity Payments."[55] This is an approach currently being tried in regions with centralized markets. However, as the draft report points out, regulatory price caps mute the price signals needed to attract appropriate amounts of new investment, and further increase investor uncertainty about whether future market prices may be by regulation. One way to compensate for this is to offer capacity payments, which provide added revenue to generation owners, but the draft report concludes that "in general, it is difficult to tell whether capacity payments alone would spur economically efficient entry."[56] The draft report also considers "Encouraging Additional Transmission Investment," implicitly as an alternative or adjunct to capacity payments, but observes: "Transmission entry may be a double-edged sword: if it is expected to occur, it would reduce the incentive of companies to consider generation entry, by eliminating the high prices they hope to capture."[57]

The final option discussed for wholesale markets is a return to cost-based regulation, described as "Governmental Control of Generation Planning and Entry." While this approach offers a measure of stability and certainty, it also can lead to "overinvestment, . . . excessive spending and unnecessarily high costs," where the price of regulatory mistakes is paid by ratepayers rather than shareholders.[58]

Chapter 4 of the draft report turns to retail competition, which currently exists in some form in sixteen states and the District of Columbia.[59] Although restructuring began almost a decade ago, the draft report observes, there has been little entry by alternative suppliers, with the result that residential customers have very little choice among suppliers, and many commercial and industrial customers are not much better off. The draft report opines that this is primarily the consequence of states' decisions to cap backup or "Provider of Last Resort" (POLR) prices at historically low levels, on the assumption that wholesale energy costs would decline. In fact, wholesale costs have risen, and the artificially low rate caps deterred new entry, since "new entrants cannot compete against a below-market regulated price."[60] This creates the "chicken-or-egg problem" that without new entry prices will rise substantially, while without substantial price increases there will never be enough new entry.[61]

55. Task Force, *supra* note 43, at 34,117.
56. *Id*.
57. Task Force, *supra* note 43, at 34,117.
58. *Id*. at 34,118.
59. Task Force, *supra* note 43, at 34,118.
60. *Id*.
61. Task Force, *supra* note 43, at 34,118.

Compounding this problem is the fact that most states required their distribution utilities to divest all or most of their generation assets, which leaves them no hedge against wholesale price increases and may threaten their solvency if they are not allowed to raise rates to cover their costs.[62]

The draft report looks in detail at the experience in seven states: Illinois, Maryland, Massachusetts, New Jersey, New York, Pennsylvania, and Texas.[63] Two broad themes emerge. First, any POLR price (politically necessary to ensure universal service) must closely approximate a competitive market price. A price capped below the competitive level will deter new entry, while a POLR price that is sometimes significantly above the competitive level "creates incentives for customers to move back and forth from POLR service to alternative [providers]," which creates inefficiency and prevents all competing providers from making efficient long-term supply arrangements.[64] Second, sending real-time price signals (or even offering simpler time-of-day rates) to at least the larger retail customers has important beneficial effects through demand-side response to price fluctuations.[65]

The draft report and its appendices contain a wealth of information and citations to numerous additional sources and studies, both state and federal. However, the draft report made no explicit recommendations and instead solicited additional public comments. More than fifty separate commenters submitted additional material in response to the draft report.

IV. MAJOR COMPETITION-RELATED FEDERAL ENERGY REGULATORY COMMISSION RULES AND ORDERS

A. Preventing Undue Discrimination and Preference in Transmission Service

On May 19, 2006, the FERC issued a Notice of Proposed Rulemaking (NOPR) entitled *Preventing Undue Discrimination and Preference in Transmission Service*,[66] in which it proposed amendments to its regulations and to the pro forma open access transmission tariff (OATT), adopted in Order Nos. 888 and 889. The OATT Reform NOPR seeks to address deficiencies in the pro forma OATT that have become apparent to the FERC since the issuance of Order Nos. 888 and 889 and that were not remedied by subsequent orders aimed at the prevention of undue discrimination and preferences in transmission, such as Order No. 2000 (regional transmission organizations) and Order No. 2003 (interconnection agreements). The OATT Reform NOPR proposes a number of significant reforms with respect to the calculation of available transfer capability (ATC), transmission planning, transmission pricing, and certain non-rate terms and conditions.

62. *Id*.

63. Task Force, *supra* note 43, at 34,118-34,128.

64. *Id*. at 34,127.

65. Task Force, *supra* note 43, at 34,127-34,128.

66. Notice of Proposed Rulemaking, *Preventing Undue Discrimination and Preference in Transmission Service*, [2006 Proposed Regs.] F.E.R.C. STATS. & REGS. ¶ 32,603 (2006), 71 Fed. Reg. 32,636 (2006) [hereinafter OATT Reform NOPR].

To ensure consistency of ATC calculations, the FERC proposes to order public utilities, working through the North American Electric Reliability Council and the North American Energy Standards Board, to develop appropriate standards.[67] To increase transparency, each transmission provider would be required to include its specific ATC calculation methodology in its OATT and to post on its open access same-time information system (OASIS) relevant data and models, as well as metrics relating to transmission requests that are approved and rejected.[68]

With respect to transmission planning, the OATT Reform NOPR proposes to require that transmission providers participate in a coordinated, open, and transparent planning process that satisfies eight planning principles set forth in the OATT Reform NOPR, which include: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, and congestion studies.[69]

The OATT Reform NOPR proposes a number of modifications with respect to transmission pricing. First, energy and generator imbalance charges would have to be related to the cost of correcting the imbalance and should encourage efficient scheduling behavior and account for the special circumstances presented by intermittent generators.[70] Second, with respect to credits for network customers, the FERC proposes to amend the pro forma OATT to provide for nondiscriminatory crediting for integrated customer-owned facilities comparable to that for the transmission provider's own facilities that are included in its rate base.[71] Third, the OATT Reform NOPR proposes to eliminate the price cap for capacity reassignment and to allow negotiated rates for transmission capacity reassigned by transmission customers, though the price cap would remain in place for capacity resold by transmission providers or their affiliates.[72]

The FERC also proposes to make several clarifications and modifications regarding non-rate terms and conditions. First, the FERC proposes to require transmission providers to consider all re-dispatch options to satisfy a request for long-term firm transmission service, or, at the transmission customer's option, to study re-dispatch options before the customer is obligated to incur the costs and delay of a transmission facilities study.[73] Second, the OATT Reform NOPR would require transmission providers to offer hourly firm point-to-point service.[74] Third, the FERC proposes to increase the minimum term for contracts with rollover rights from the current one year to five years and the time for exercising a right of first refusal to renew the contract from the current sixty-day period to one year.[75] Fourth, the OATT Reform NOPR proposes to clarify the requirements for designating network resources with respect to the types of

67. *Id.* at P 169.

68. OATT Reform NOPR, *supra* note 66, at PP 171-72, 195.

69. *Id.* at P 214.

70. OATT Reform NOPR, *supra* note 66, at P 239.

71. *Id.* at P 257.

72. OATT Reform NOPR, *supra* note 66, at P 270.

73. *Id.* at PP 308-11.

74. OATT Reform NOPR, *supra* note 66, at P 343.

75. *Id.* at PP 355.

agreements covered and required documentation, and would require transmission providers and network customers to use OASIS to request designation or undesignation of network resources.[76] Finally, to increase transparency, the OATT Reform NOPR would require transmission providers to post on their OASIS all business rules, practices and standards, and to include credit review procedures in their OATT.

B. Market-Based Rates for Wholesale Sales of Electric Energy, Capacity, and Ancillary Services by Public Utilities

On May 18, 2006, the FERC issued a NOPR entitled *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity, and Ancillary Services by Public Utilities*,[77] in which it proposes to codify and, in certain respects, revise its current standards for authorizing public utilities to charge market-based rates for sales of electric energy, capacity, and ancillary services. The FERC would retain the overall framework of its current market-based rate regime, but with modifications in the following areas: the horizontal, or generation, market power analysis; vertical market power analysis; affiliate abuse; streamlined procedures for administration of market-based rate program; and the codification of a market-based rate tariff of general applicability.

With respect to its horizontal market power analysis, the FERC proposes first to eliminate the exemption for generation capacity constructed after 1996—an exemption currently contained in section 35.27 of the FERC's regulations to avoid a situation in which all generation becomes exempt as new generation is constructed and pre-1996 generators are retired.[78] Second, the Market-Based Rates NOPR proposes additional guidance for sellers and intervenors seeking to demonstrate that the relevant geographic market is larger or smaller than the current default market definition (i.e., either a control area or the footprint of a given ISO/RTO with a single energy market).[79] Third, the FERC would change the native load proxy used from the minimum peak day in a given season to the average native peak load and to clarify that native load only includes load attributable to native load customers.[80] In addition, the Market-Based Rates NOPR seeks comments on various aspects of its current methodology for mitigating horizontal market power, including: (i) the rate methodology for designing cost-based mitigation; (ii) discounting; (ii) protection of customers in

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76. OATT Reform NOPR, *supra* note 66, at PP 402-23.

77. Notice of Proposed Rulemaking, *Market-Based Rates for Wholesale Sales of Elec. Energy, Capacity, and Ancillary Servs. by Public Utils.*, [2006 Proposed Regs.] F.E.R.C. STATS. & REGS. ¶ 32,602, 71 Fed. Reg. 33,102 (2006) [Market-Based Rates NOPR].

78. *Id.* at P 70 (citing 18 C.F.R. § 35.27 (2006)).

79. For example, a proposal to use a larger geographic market would have to demonstrate, using historical data, whether or not there are frequently binding transmission constraints during peak periods or other competitively significant periods. Other relevant evidence would include: single transmission rate, common OASIS for scheduling transmission service, correlation of price movements, and evidence of active trading throughout the proposed geographic market. Market-Based Rates NOPR, *supra* note 77, at PP 53-57. In addition, the FERC seeks comment as to whether ISO/RTOs should be divided into smaller submarkets for study purposes due to binding transmission constraints and what general criteria the FERC should use for defining ISO/RTO submarkets. *Id.* at PP 58-61.

80. Market-Based Rates NOPR, *supra* note 77, at PP 44-45.

mitigated markets; and (iv) sales by mitigated sellers that "sink" in unmitigated markets.[81]

With respect to vertical market power, the Market-Based Rates NOPR proposes to continue the current policy under which a transmission provider's OATT on file with the FERC is deemed to mitigate any transmission market power. However, the FERC proposes that OATT violations may be cause to revoke the seller's market-based rate authority in a given market, as well as that of any affiliates with market-based rate authority, in addition to any other applicable remedies.[82]

The Market-Based Rates NOPR proposes to streamline and replace the FERC's existing four-prong analysis (generation market power, transmission market power, other barriers to entry, affiliate abuse/reciprocal dealing) with an analysis limited to horizontal market power and vertical market power, in which barriers to entry and affiliate abuse would be addressed as part of the vertical market power analysis.[83] The analysis of other barriers to entry will continue to consider inputs to electric power production as before, though the FERC proposes to eliminate from its consideration interstate transportation of natural gas because such transportation is regulated by the FERC.[84]

The Market-Based Rates NOPR proposes to address affiliate abuse by requiring that the conditions set forth in the proposed regulations, including a uniform market-based rate tariff (contained in Appendix A of the Market-Based Rates NOPR)[85] and code of conduct,[86] be satisfied on an ongoing basis as a condition of obtaining and retaining market-based rate authority.

Finally, the FERC proposes to modify the requirements for filing an updated market power analysis by establishing separate procedures for two

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81. *Id*. at P 138. In particular, the FERC seeks comments on how to protect customers in mitigated markets where a seller subject to mitigation in a given geographic market need not offer any capacity in that market, but instead is free to market all its excess capacity at market-based rates in other geographic markets. Therefore, the FERC seeks comments as to whether such mitigated sellers should have their market-based rate authority revoked for sales outside their home control area as well or whether they should instead be subject to some form of "must offer" requirement in mitigated markets to prevent withholding. Market-Based Rates NOPR, *supra* note 77, at P 146.

82. *Id.* at P 91.

83. Market-Based Rates NOPR, *supra* note 77, at P 89.

84. *Id.* at P 93.

85. The uniform market-based rate tariff, to be codified in a new section 35.42 of FERC's regulations, would replace the individual market-based rate tariffs for each market-based rate seller. Market-Based Rates NOPR, *supra* note 77, at P 161.

86. The proposed uniform code of conduct would be generally identical to the current code of conduct with the following modifications. First, the proposed code of conduct uses the term "non-regulated" affiliates instead of power marketer or power producer to make it clear that the provisions apply to the relationship between a franchised public utility and any of its affiliates that are not regulated under cost-based regulation, including, for example, exempt wholesale generators and qualified facilities. Second, the proposed code of conduct treats any companies that act on behalf of or for the benefit of franchised public utilities (*e.g.*, pursuant to an asset or energy management agreement) as the franchised public utility to ensure that the same restrictions on information sharing apply to this third-party entity as do to the franchised public utility itself. *Id.* at PP 127-31. In addition, the FERC proposes to amend its regulations to include a provision expressly prohibiting power sales between a franchised public utility and any of its non-regulated affiliates without first receiving FERC authorization of the transaction under section 205. Market-Based Rates NOPR, *supra* note 77, at P 109.

categories of market-based rate sellers: Category I sellers, consisting of smaller generators and power marketers; and Category II sellers, consisting of larger generators that are themselves, or are affiliates, of public utilities with franchised service territories.[87] Category I sellers would not be required to file an updated market power analysis, and the FERC would monitor these sellers through the change in status reporting requirement.[88] Category II sellers will continue to be required to file regularly-scheduled triennial reviews, a requirement that would be codified in the proposed regulations.[89]

C. Amendments to Market Behavior Rules

On February 16, 2006, the FERC issued two companion orders amending the Market Behavior Rules applicable to jurisdictional sellers of natural gas[90] and public utilities with market-based rates.[91] These orders rescinded Market Behavior Rules 2 and 6 and retained and codified Market Behavior Rules 1, 3, 4, and 5 in the FERC's regulations.[92]

With respect to Market Behavior Rule 2, the FERC noted that its central purpose in adopting this rule was to prohibit market manipulation.[93] Subsequently, Congress provided the FERC with explicit anti-manipulation authority in sections 315 and 1,283 of the EPAct 2005,[94] which the FERC implemented in Order No. 670.[95] Thus, the FERC found it necessary to rescind

87. Category I (with roughly 550 sellers) consists of power marketers or power producers that own or control 500 MW or less of generating capacity and that are not affiliated with any public utility with a franchised service territory and that do not own or control transmission facilities. Category II (roughly 600 sellers) includes all market-based rate sellers that do not qualify for Category I. Market-Based Rates NOPR, *Id.* at PP 152-53.

88. Market-Based Rates NOPR, *supra* note 77, at PP 152.

89. In addition, the FERC would require all Category II market-based rate sellers in a given geographic area (and contiguous markets within a region from which power could be imported) to file at the same time. This will allow the FERC to examine both individual sellers and the markets as a whole, giving the FERC a complete picture of uncommitted capacity and simultaneous import capability into the relevant geographic market. *Id.* at PP. 153-55.

90. Order 673, *Amendments to Codes of Conduct for Unbundled Sales Service and for Persons Holding Blanket Marketing Certificates*, [2006 Proposed Regs.] F.E.R.C. STATS. & REGS. ¶ 31,207 (2006), 71 Fed. Reg. 9,709 (2006) [hereinafter Order No. 673].

91. *Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations*, 115 F.E.R.C. ¶ 61,174 (2006) [hereinafter *Electric Market Behavior Rules*].

92. With respect to public utilities with market-based rate authorization, the FERC removed Market Behavior Rules 1, 3, 4, and 5 from their market-based rate tariffs and codified them in sections 35.36 and 35.37 of the FERC's regulations with no substantive changes. Those applicable to jurisdictional sellers of natural gas were already codified at sections 284.288 and 284.403 of the FERC's regulations. 18 C.F.R. §§ 284.288, 284.403 (2006).

93. Market Behavior Rule 2 prohibited "actions or transactions that are without a [legitimate] business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules for electric energy or electricity products . . . ." 18 C.F.R. §§ 284.288(a), 284.403(a) (natural gas); *Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations*, 105 F.E.R.C. ¶ 61,218 (2003), *reh'g denied*, 107 F.E.R.C. ¶ 61,175 (2004) (electric).

94. Energy Policy Act of 2005 §§ 315 (adding 15 U.S.C. 717c-1 and 16 U.S.C. § 824v).

95. Order No. 670, *Prohibition of Energy Market Manipulation*, [2006 Proposed Regs.] F.E.R.C. STATS. & REGS. ¶ 31,202 (2006), 71 Fed. Reg. 4244 (Jan. 26, 2006) (codified as 18 C.F.R. Pt. 1c (2006)). These provisions made it unlawful for any entity to engage in fraudulent or deceptive conduct in connection with the

Market Behavior Rule 2 from its regulations to avoid regulatory uncertainty or duplicative regulation.[96]

The FERC rejected suggestions to retain Market Behavior Rule 2 because its foreseeability standard was arguably broader than the *scienter* standard of Order No. 670. According to the FERC, the lower standard of Market Behavior Rule 2 is inconsistent with congressional intent to adopt a *scienter* standard for manipulation.[97] The FERC also rejected calls to retain the specific prescribed behaviors in Market Behavior Rule 2 (i.e., wash trades and collusion) because in Order No. 670, the FERC explicitly prohibited these behaviors.[98] Finally, the FERC rejected suggestions to retain the "legitimate business purpose defense" as inconsistent with congressional intent that the FERC model its anti-manipulation rule on SEC Rule 10b-5[99] (which does not provide for a "good faith" defense), though it noted that the intent and rationale behind actions will be taken into consideration to determine whether the actions in question constitute manipulation.[100]

The FERC also rescinded Market Behavior Rule 6, which requires market-based rate sellers to adhere to their code of conduct, and addresses remedies for violations thereof. The FERC found it unnecessary to codify this rule for public utilities because the standards of conduct adopted in Order No. 2004 are already codified in the FERC's regulations, and many sellers have already included a code of conduct in their market-based rate tariffs as a condition of the market-based rate authority.[101] With respect to jurisdictional sellers of natural gas, the FERC found that there was no longer a need for Market Behavior Rule 6 in light of the FERC's enhanced civil penalty authority under EPAct 2005 and the other applicable remedies for violations of the FERC's regulations.[102]

D. Generation Market Power Review and Mitigation Orders

In a number of orders issued in 2006, the FERC found that public utilities with market-based rate authority possessed generation market power, based on their failure of one or more of the FERC's generation market power screens. The FERC required these entities to either adopt mitigation measures or revoked

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purchase or sale of electric energy, natural gas, or transmission or transportation services subject to the FERC jurisdiction.

96. Order No. 673, *supra* note 90, at P 1; *Electric Market Behavior Rules*, *supra* note 91, at P 1.

97. The FERC further noted the potential for uneven application given that Order No. 670 applies to non-jurisdictional entities that are not subject to Market Behavior Rule 2. According to the FERC, it would not be appropriate to maintain a lesser standard of proof for only jurisdictional entities. Order No. 673, *supra* note 90, at P 18; *Electric Market Behavior Rules*, *supra* note 91, at P 21.

98. Order No. 673, *supra* note 90, at P 19; *Electric Market Behavior Rules*, *supra* note 91, at P 24.

99. 17 C.F.R. § 240.10b-5 (2006) (codified as 15 U.S.C. § 78j (2000)).

100. Order No. 673, *supra* note 90, at P 24; *Electric Market Behavior Rules*, *supra* note 91, at P 29. In addition, the FERC rejected requests to retain Market Behavior Rule 2 to curb market power or other anti-competitive behavior because the purpose of the anti-manipulation rules is to prevent fraudulent or deceptive practices as a means of manipulation. Market power, by contrast, is a structural issue to be remedied, not by behavioral means, but by processes to identify and, where necessary, mitigate it, *e.g.*, through the FERC's procedures for granting applications and overseeing grants of market-based rate authority and through ISO/RTO market rules and market monitoring. *Electric Market Behavior Rules*, *supra* note 91, at PP 22-23.

101. *Id*. at P 46.

102. Order No. 673, *supra* note 90, at PP 38-41.

their market-based rate authority for the geographic market(s) in which they were found to have generation market power. The more significant cases are summarized below.

In *South Carolina Electric & Gas Co.* (SCE&G),[103] the FERC conditionally accepted SCE&G's proposal to amend its market-based rate tariff to prohibit all market-based rate sales in its home control area, absent prior FERC approval. The mitigation proposal applied on a prospective basis only, so that existing contracts would not be affected.

In *MidAmerican Energy Co.* (MidAmerican),[104] the FERC accepted MidAmerican's commitment not to make sales under its market-based rate tariff in its home control area, but rejected proposed language that would limit this restriction on market-based rate sales to those that sink in the MidAmerican control area.[105] In addition, the FERC rejected MidAmerican's proposal to use a market-based cap for non-firm short-term energy sales (i.e., for sales from one hour to one month), based on the PJM locational marginal prices at the PJM-MidAmerican interface because mitigated rates must be cost-based.[106]

In *Oklahoma Gas & Electric Co.* (OG&E Companies),[107] the FERC conditionally accepted OG&E Companies' mitigation proposal to adopt the FERC's default cost-based rates for sales of power for short-term sales (i.e., for sales from one hour to one week) set forth in the April 14 Order as part of their market-based rate tariffs.[108] As in *MidAmerican*, the FERC rejected the proposed tariff language that limited mitigated sales to loads that sink in the OG&E control area.[109]

In *Pinnacle West Capital Corp.* (Pinnacle West Companies),[110] the FERC revoked the market-based rate authority of Pinnacle West Companies for the Arizona Public Service Company (APS) control area.[111] The FERC emphasized that it did so based on the numerous deficiencies in Pinnacle West Companies'

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103. *South Carolina Elec. and Gas Co.*, 114 F.E.R.C. ¶ 61,410 (2006) [hereinafter *South Carolina*].

104. *MidAmerican Energy Co.*, 114 F.E.R.C. ¶ 61,280, *order on compliance and settlement*, 114 F.E.R.C. ¶ 61,178 (2006) [hereinafter *MidAmerican*].

105. *Id.* at P 31. The FERC found that MidAmerican's proposal inappropriately limited mitigation sales to those buyers that serve end-use customers in the MidAmerican control area. According to the FERC, this proposal would improperly allow MidAmerican to make market-based rate sales within its control area to any entities that do not serve end-use customers in the MidAmerican control area, which would not mitigate its ability to exercise market power in its control area. The FERC emphasized that it had explicitly rejected this proposal in the rehearing of the April 14 Order. *Id.* at P 32 (citing *AEP Power Mktg., Inc.*, 107 F.E.R.C. ¶ 61,018 (2004), *order on reh'g*, 108 F.E.R.C. ¶ 61,026 (2004)).

106. *MidAmerican*, *supra* note 104, at P 43. The FERC set for a trial-type hearing portions of MidAmerican's proposed power sales tariff concerning charges for negotiated capacity and energy and rejected its proposed mitigation with respect to short-term energy sales. The issues set for hearing and relating to the price caps for short-term sales were subsequently settled and accepted by the FERC. *See id.*

107. *Oklahoma Gas and Elec. Co*., 114 F.E.R.C. ¶ 61,297 (2006) [hereinafter *OG&E*].

108. The FERC accepted the proposal, but found that such cost-based rates are more appropriately included in a separate tariff filing and directed OGE Companies to do so and to include the formulas and methodology used to calculate incremental costs for short-term sales. *Id.* at P 19.

109. *OG&E*, *supra* note 107, at PP 20-22 (citing July 8 Order, 108 F.E.R.C. ¶ 61,026 at P 134). The FERC also rejected this restriction on mitigation for sales for a term of one week to one year. *Id.* at P 24.

110. *Pinnacle W. Capital Corp*., 115 F.E.R.C. ¶ 61,055 (2006) [hereinafter *Pinnacle West*].

111. Pinnacle West Companies includes Pinnacle West Capital Corporation, Arizona Public Service Company, and various affiliates.

simultaneous import capability study, as a result of which the FERC was unable to rely on it either for the generation market power screens or the Delivered Price Test,[112] and the fact that the FERC had provided ample time and opportunity for Pinnacle West Companies to correct the deficiencies. According to the FERC, Pinnacle West Companies' failure to do so violated a directive in a previous compliance order and a condition of its market-based rate authority.[113] The FERC further directed the Pinnacle West Companies to submit a compliance filing adopting the FERC's default cost-based rates for mitigation in the APS control area because they did not propose tailored mitigation or cost-based mitigation, as outlined in the April 14 Order.[114]

In *Southern California Edison Co.* (SoCal Edison),[115] the FERC accepted SoCal Edison's generation market power screens, but declined SoCal Edison's request that it be allowed to use forward-looking generation market power screens.[116] The FERC declined this request, reiterating that the delivered price test is the only forward-looking test that applicants may use and that SoCal Edison would still be required to provide a change in status filing pursuant to Order No. 652 any time that its purchases resulted in a cumulative increase of one-hundred MW or more.[117]

E. Southern Co. Services, Inc.[118]

On October 5, 2006, the FERC accepted in part and rejected in part a proposed settlement submitted by Southern Company Services, Inc. and its various affiliates (collectively Southern Companies),[119] on the one hand, and, on the other, Calpine Corporation (Calpine), Coral Power, L.L.C. (Coral), and the Board of Water, Light, and Sinking Fund Commissioners of the City of Dalton (collectively, Settling Parties). This proceeding began on October 5, 2005, when, in response to complaints by Calpine and Coral, the FERC instituted an investigation to determine whether the role of Southern Power in the Southern

112. These deficiencies included the failure to demonstrate that its study reflected actual historical operating conditions and its failure to provide supporting data. *Pinnacle West*, *supra* note 110, PP 51-54.

113. *Id.* at P 56. In addition, the FERC rejected Pinnacle West Companies' request that the limitation on market-based rates only apply to wholesale load within the APS control area, for the same reasons it did so in *MidAmerican* and *OG&E*.

114. *Pinnacle West*, *supra* note 110, PP 62-64.

115. *Southern Cal. Edison Co*., 114 F.E.R.C. ¶ 61,268 (2006) [hereinafter *SoCal Edison*].

116. SoCal Edison requested that it be allowed to use these forward-looking screens as the economic analysis required for future changes in status and that the FERC find that SoCal Edison was not required to update the analysis until the date of its next triennial filing because SoCal Edison intends to be an active purchaser of wholesale power through long-term contracts that will result in frequent changes in status that must be reported under Order No. 652. *SoCal Edison*, *supra* note 115, at P 14 (citing Order No. 652, *Reporting Requirement for Changes in Status for Public Utilities with Market-Based Rate Authority*, F.E.R.C. STATS. & REGS. ¶ 31,175 (2005), 70 Fed. Reg. 8253 (2005)).

117. *SoCal Edison*, *supra* note 115, at P 15.

118. *Southern Co. Servs., Inc.* 117 F.E.R.C. ¶ 61,021 (2006) [hereinafter *Southern Companies*].

119. Southern Company Services, Inc. was acting for itself and as agent for several affiliates, including Southern Power Company (Southern Power) and various regulated public utilities with franchised service territories (collectively Southern Operating Companies).

Operating Companies' generation "pool" was consistent with the FERC's regulations and precedents regarding affiliate abuse.[120]

The most significant provisions of the proposed settlement were as follows: (i) Southern Operating Companies would continue to treat Southern Power as a "system company" under its code of conduct, with limited restrictions on sharing of information; (ii) Southern Power would be able to enter into long-term sales (i.e., one year or longer) contracts with Southern Operating Companies provided that it entered into the contract pursuant to a competitive solicitation process and Southern Power could retain profits from all sales of longer than one week; and (iii) Southern Operating Companies would provide back-up power service to Coral and Calpine, but not to other merchant generators.[121]

The FERC refused to accept the proposed settlement because it did not adequately protect against affiliate abuse and ordered significant changes to the proposed settlement. First, with respect to Southern Power's treatment as a "system company," the FERC required Southern Operating Companies to adopt a clear separation of functions (including restrictions on information sharing, and a separation of Southern Power sales personnel and Southern Operating Companies sales personnel) to ensure that Southern Operating Companies cannot favor Southern Power sales or provide it with preferential access to marketing or planning information.[122]

Second, the FERC modified the proposed settlement to ensure that Southern Power cannot receive undue preference in power sales to or from Southern Operating Companies.[123] Third, the FERC required that all similarly-situated merchant generators be given access to back-up power from the Southern Operating Companies.[124] Finally, the FERC required that all provisions of the proposed settlement relating to non-discriminatory access to transmission service

120. *See Southern Co. Servs., Inc.*, 111 F.E.R.C. ¶ 61,146 (2005), *clarified*, 112 F.E.R.C. ¶ 61,015 (2005). There, the FERC set for hearing the following issues: (1) the justness and reasonableness of the Intercompany Interchange Contract (IIC), including the justness and reasonableness of Southern Power's continued inclusion in the Southern Operating Companies pool and whether the inclusion of involves undue preference or undue discrimination; (2) whether any of the Southern Operating Companies, including Southern Power, have violated or are violating the standards of conduct under Part 358 of the FERC's regulations; and (3) whether Southern Operating Companies code of conduct is just and reasonable and whether the code of conduct itself should continue to define Southern Power as a "system company."

121. *Southern Companies*, *supra* note 118, at PP 8-15.

122. *Id.* at PP 33-37. The FERC emphasized that, under its precedent, a competitive affiliate of regulated public utilities must completely separate its functions from those of its regulated affiliates, including separate sales staffs, restrictions on the sharing of any market information between regulated and unregulated affiliates, and separate staffs for any function covered by the Communications Protocol governing information sharing between Southern Power and Southern Operating Companies. Accordingly, Southern Operating Companies were directed to revise the code of conduct, Communications Protocol, and associated provisions of the IIC. *Southern Companies*, *supra* note 118, at PP 34-37 (citing *Montana-Dakota Utils.*, 85 F.E.R.C. ¶ 61,062 (1998); *Heartland Energy Servs., Inc.*, 68 F.E.R.C. ¶ 61,233 (1994)).

123. *Southern Companies*, *supra* note 118, at P 42. With respect to power sales from Southern Power to Southern Operating Companies, the Commission found that the proposed settlement was ambiguous as to the treatment of sales shorter than one year but longer than transactions entered into pursuant to joint economic dispatch. The FERC therefore required that the IIC be modified to require prior FERC approval under section 205 for any such sales. *Id.* Similarly, any sales from Southern Operating Companies to Southern Power (other than through joint economic dispatch, which are priced at variable cost) would require prior FERC approval. *Southern Companies*, *supra* note 118, at P 46.

124. *Id.*

be incorporated into the IIC itself. The FERC found these modifications necessary to make clear that all transmission service provided to Southern Power would be provided pursuant to the OATT and that nothing in the IIC would permit sharing of information contrary to the standards of conduct.[125]

V. JUDICIAL DECISIONS

A. *National Fuel Gas Supply Corp. v. FERC*

On November 17, 2006, the United States Court of Appeals for the District of Columbia Circuit in *National Fuel Gas Supply Corp. v. FERC*[126] vacated and remanded Order No. 2004, which had imposed comprehensive standards of conduct on the relationship between natural gas pipelines and their energy affiliates. The new rules also applied to the relationship between electric utilities and their energy affiliates. The rule was appealed, however, only by natural gas pipelines, not by electric utilities.

By way of background, when the FERC mandated the unbundling of pipeline sales and transportation services in the 1980's, pipelines formed marketing affiliates to perform the sales function. In response to complaints that pipelines were favoring their marketing affiliates, the FERC in 1988 issued Order No. 497 establishing standards of conduct governing pipeline interactions with their natural gas marketing affiliates. These standards were upheld by the D.C. Circuit in 1992.[127] In Order No. 2004, the FERC extended these standards of conduct to all energy affiliates, not just gas marketing affiliates. Among other things, the FERC's new rules required interstate gas pipelines to function independently from electric generation affiliates, as well as from other natural gas affiliates in the supply chain including natural gas producers, gatherers, processors, and local distribution companies making off-system sales. These requirements also applied to electric utilities and their energy affiliates. The rules imposed an intricate set of regulations governing the extent to which employees, facilities, and information could be shared among transmission providers (i.e., gas pipelines and electric utilities) and their energy affiliates. Pipelines asserted, among other things, that the FERC's new rules were unnecessary, and were essentially a solution in search of a problem. In addition, pipelines complained that the new rules lacked clarity as to what was required or prohibited in practice. When the FERC rejected these arguments, pipelines sought judicial review of Order No. 2004.

In its opinion vacating Order No. 2004, the D.C. Circuit noted that the FERC had estimated compliance with the rules would cost the industry $240 million annually.[128] Based on a comprehensive review of the evidence proffered by the FERC in support of the rule, the court found no evidence that pipelines

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125. *Southern Companies*, *supra* note 118, at PP 52-55. In particular, the FERC required that Southern Operating Companies make clear that Southern Power is to be treated as an Energy Affiliate under the standards of conduct and therefore cannot receive any non-public transmission information. *Id.* at P 54.

126. National Fuel Gas Supply Corp. v. FERC, 468 F.3d 831 (D.C. Cir. 2006).

127. Tenneco Gas v. FERC, 969 F.2d 1187 (D.C. Cir. 1992).

128. *National Fuel Gas Supply Corp.*, 468 F.3d at 837.

had engaged in the types of abuses the rules were intended to prevent.[129] In short, the FERC had pointed to no evidence that pipelines had been unduly discriminating in favor of non-marketing affiliates. Therefore, the court held that the FERC had failed to support an extension of the standards of conduct to non-marketing affiliates, and that the FERC's rules were not the product of reasoned decision-making. The court noted that the FERC had also attempted to support the rule based on the *theoretical* threat that pipelines would abuse their relationship with their non-marketing affiliates.[130] While not ruling on this claim, the court listed a number of hurdles that the FERC must overcome if it decided on remand to re-promulgate the same rules on the basis of this rationale.[131]

On remand, the FERC has proposed, among other things, to abandon its effort to extend the standards of conduct to all energy affiliates, rather than attempt to provide a new rationale or evidence that would support the regulations originally promulgated in Order No. 2004, which the court remanded.[132]

B. Public Utility District No. 1 of Snohomish v. FERC

In *Public Utility District No. 1 of Snohomish v. FERC*,[133] the Court of Appeals for the Ninth Circuit remanded to the FERC for reconsideration orders in which the FERC, relying on the *Mobile-Sierra* doctrine,[134] rejected complaints seeking to modify long-term wholesale power contracts executed in the Western energy markets during the energy crisis of 2000 and 2001. The court held that the FERC's reliance on *Mobile-Sierra* was misplaced "because its grant of market-based rate authority lacked a mechanism to provide effective, timely relief from unjust and unreasonable rates due to market dysfunction, thereby creating a gap in the FPA's protection against excessive energy prices."[135]

According to the court, there are three preconditions for the *Mobile-Sierra* doctrine.[136] First, the contract itself must not expressly preclude *Mobile-Sierra* review (e.g., by means of "Memphis Clause" expressly reserving the right to make unilateral changes to the contract). Second, there must be "timely and procedurally effective review of rates . . . ."[137] Finally, there must be

129. *Id.* at 841

130. *National Fuel Gas Supply Corp*., 468 F.3d at 842.

131. *Id.* at 844-45.

132. *Standards of Conduct for Transmission Providers*, 118 F.E.R.C. ¶ 61,031 (2007).

133. Public Util. Dist. No. 1 of Snohomish v. FERC, 471 F.3d 1053 (9th Cir. 2006). On the same day, the court issued a separate opinion in which it applied its holdings in *PUD Snohomish* to another set of contracts and remanded these contracts to FERC to apply the standards of review outlined in *PUD Snohomish*. Public Util. Comm. of Cal. v. FERC, 474 F.3d 587 (9th Cir. 2006). These contracts included agreements involving Coral Power, Dynegy Power Marketing, Mirant Americas Energy Marketing, Pacificorp, and Sempra Energy Resources. This case does not contain any significant new analysis or holdings, and will not be discussed further here.

134. United Gas Pipe Line Co. v. Mobile Gas Serv. Corp., 350 U.S. 332 (1956); FPC v. Sierra Pac. Power Co., 350 U.S. 348 (1956).

135. *Public Util. Dist. No. 1 of Snohomish*, 471 F.3d at 1057.

136. The court began its analysis by emphasizing that "there is but one statutory standard addressing the lawfulness of wholesale electricity rates," which is that all rates be just and reasonable, dismissing suggestions in other cases that the *Mobile-Sierra* doctrine embodies a higher "public interest standard." *Id.* at 1074.

137. *Public Util. Dist. No. 1 of Snohomish*, 471 F.3d at 1075.

"meaningful substantive standards for review of the circumstances of contract formation."[138] Thus, the *Mobile-Sierra* embodies a presumption that "as long as the rate was just and reasonable when the contract was formed . . . the reasonableness continued throughout the term of the contract."[139]

The court held that the last two conditions were not satisfied with respect to the challenged contracts and that the FERC was therefore not entitled to rely on this *Mobile-Sierra* presumption. The court agreed that, while the FERC's grant of market-based rate authority "*can* qualify as sufficient prior review to justify limited *Mobile-Sierra* review, it can only do so when accompanied by effective oversight permitting timely reconsideration of market-based authorization if market conditions change,"[140] which was lacking in the present case. According to the court, the FERC's oversight after the initial grant of market-based rate authority was deficient because the "FERC failed to adopt any monitoring mechanism before applying deferential *Mobile-Sierra* review . . . ."[141] The court also rejected the FERC's argument that its quarterly reporting requirement fulfilled its statutory oversight function because this reporting requirement would only allow the FERC to discover market dysfunction after the contracts had been entered into. Further, the FERC's position that remedies were only available on a prospective basis would prevent FERC review of contracts entered into during the prior period.[142] According to the court, "the fatal flaw in [the] FERC's approach to 'oversight' is that it precludes timely consideration of sudden market changes and offers no protection to purchasers victimized by the abuses of sellers or dysfunctional [spot] market conditions that [the] FERC itself notices only in hindsight."[143]

The court further concluded that the FERC erred by treating staff's conclusions regarding dysfunction in the spot market as irrelevant to the question of whether *Mobile-Sierra* applied to contracts in the forward market.[144] The

138. *Id.* at 1075-76.

139. *Public Util. Dist. No. 1 of Snohomish*, 471 F.3d at 1077.

140. *Id.* at 1080.

141. Public Util. Dist. No. 1 of Snohomish v. FERC, 471 F.3d 1053, 1082 (9th Cir. 2006). Here, the court emphasized that in the challenged orders, the FERC relied solely on the orders initially granting market-based rate authority to apply *Mobile-Sierra*, which were issued long before the alleged market failures, without any inquiry into whether the resulting rates were in fact just and reasonable. *Id.*

142. *Public Util. Dist. No. 1 of Snohomish*, 471 F.3d at 1084 (discussing *Enron Power Mktg., Inc*., 103 F.E.R.C. ¶ 61,343 (2003), *order on initial decision*, 103 F.E.R.C. ¶ 62,397 (2003)). The court used the following example based on the circumstances present in *Enron* to demonstrate that the FERC has no opportunity to review whether the contracts at issue are just and reasonable before they are entered into. The FERC grants market-based rate authority to a seller in Year 1, and then in Year 5, short-term prices increase dramatically due to the seller's manipulation or abuse of market power. The FERC subsequently discovers in Year 6 through its review of the contracts or the subsequent price reports that the assumptions upon which its grant of market-based rate authority was based, namely that there is a well-functioning, competitive market or that the seller lacks market power, are no longer correct. The court rejected the FERC's position that it can only revoke market-based rate authority or order refunds on a prospective basis from Year 6 forward and that it cannot review the contracts entered into during Year 5. According to the court, this is precisely what occurred in *Enron*: the day after the FERC revoked Enron's market-based rate authority because of actions taken during the time period during which the contracts at issue were entered into, the FERC denied requests to reform its contracts with Enron by applying the *Mobile-Sierra* "public interest standard."

143. *Id.* at 1084.

144. *Public Util. Dist. No. 1 of Snohomish*, 471 F.3d at 1087.

court held that the FERC is not obligated to justify its decision to adopt a different approach from that suggested by staff, but when "the conceptual underpinnings of the staff's approach are critical to a reasoned resolution of the problem," then the FERC must address them.[145]

Finally, the court held that the FERC erroneously applied "factors taken from the context of a *low-rate* challenge rather than those relevant to the *high-rate* challenge . . . ."[146] According to the court, the FERC acknowledged that the challenged contracts increased retail rates, but erroneously dismissed these complaints by finding that this increase did not impose an "excessive burden" on consumers.[147]

C. *California ex rel. Lockyer v. Powerex Corp.*

In *California ex rel. Lockyer v. Powerex Corp.*,[148] the District Court for the Eastern District of California held that the California Attorney General's (California) motion to remand its state antitrust law claims to state court was barred by the filed rate doctrine.[149] California alleged that the defendants had violated state antitrust laws by misrepresenting in-state electricity as higher-priced out-of-market (OOM) electricity, which was not subject to the price caps for in-state electricity. While California agreed that any claim that required determining a reasonable rate for wholesale electricity would be precluded by the filed rate doctrine, California argued that its theory of recovery did not require such a determination and that recovery could instead be determined by relying on historical fixed prices for OOM and in-state energy during the relevant time period.[150]

The court rejected this theory because it "simply shifts the substantial issue of federal law from determining the rate to classifying the power" as in-state or OOM. According to the court, a "reasonable rate determination necessarily requires the classification of the power."[151] Therefore, "classification of the power is within [the] FERC's exclusive jurisdiction and, therefore, presents a substantial, disputed issue of federal law."[152]

145. *Id.* (citing Public Utils. Comm'n v. FERC, 817 F.2d 858, 862-63 (D.C. Cir. 1987)).

146. Public Util. Dist. No. 1 of Snohomish v. FERC, 471 F.3d 105, 1087 (9th Cir. 2006). According to the court, "[t]he primary 'public interest' at issue in a low-rate challenge, such as *Sierra*, is in keeping utilities in operation so the public is not deprived of services. . . . In contrast, the key 'public interest[,]' in a high-rate challenge, such as this one, is assuring . . . the consuming public pays fair rates . . . ." *Id.* at 1088.

147. *Public Util. Dist. No. 1 at Snohomish*, 471 F.3d at 1089.

148. California *ex rel*. Lockyer v. Powerex Energy Corp., No. CIV-S-05-01216 DFL DAD, 2006 U.S. Dist. LEXIS 19634 (E.D. Ca. Apr. 14, 2006).

149. Specifically, the court dismissed California's motion to remand, holding that the claim fell within the subject matter jurisdiction of the federal courts because plaintiff's right to relief depends on the resolution of a substantial, disputed federal question, which falls within the exclusive jurisdiction of the FERC. *Id.* at *12.

150. *California ex rel. Lockyer*, 2006 U.S. Dist. LEXIS 19634 at *10.

151. *Id.* at *10-11.

152. *California ex rel. Lockyer*, 2006 U.S. Dist. LEXIS 19634 at *12.

D. Borough of Lansdale v. PP&L, Inc.

In *Borough of Lansdale v. PP&L, Inc.*,[153] the District Court for the Eastern District of Pennsylvania granted defendant PPL Corporation's motion for summary judgment regarding plaintiff municipalities' various Sherman Act and Clayton Act claims.[154] Plaintiffs first claimed that the Joint Petition filed by PPL and various intervenors (along with related agreements between these same parties) in restructuring proceedings before the Pennsylvania Public Utilities Commission (PUC) constituted *per se* illegal price fixing and market allocation agreements.

Relying on the findings in the related proceeding in *Borough of Olyphant v. PPL*,[155] the court held that the Joint Petition and the related agreements did not provide evidence of a price-fixing or market-allocation agreement because they do not mention rates or customers, nor did they seek to prevent customers from choosing a competing supplier. Instead, they simply memorialized the signatory party's intent to sign the Joint Petition.[156] Moreover, the court found that PPL was complying with its statutory obligation to serve as a POLR for customers that were unable to purchase electricity from another utility.[157] Finally, the court rejected the plaintiffs' claims regarding the Joint Petition under the *Noerr-Pennington* doctrine because the Joint Petition "did not effectuate any changes to the rates, but rather requested the PUC to make changes to PPL rates,"[158] as it requested that the Pennsylvania PUC make changes to PPL rates that had already been approved by the Pennsylvania PUC in prior restructuring orders.

The court found that plaintiffs' price squeeze and monopolization claims were barred by the filed rate doctrine because these claims implicated FERC-approved wholesale rates.[159] The court also rejected plaintiffs' argument that their claims qualified for the competitor exception to the filed rate doctrine because plaintiffs were PPL customers under the power supply agreements and in the ICAP market, despite the fact that they were competitors at the retail

153. Borough of Lansdale v. PP&L, Inc., 426 F. Supp. 2d 264 (E.D. Pa. 2006).

154. Pursuant to Pennsylvania's law regarding retail choice and restructuring of the electric power industry, PPL was required to submit to the Pennsylvania PUC a restructuring plan to implement state law requirements. As a result of contested proceedings before the Pennsylvania PUC, PPL and thirty-six intervening parties submitted a Joint Petition to the PUC for PPL to remain the provider of last resort (POLR) for retail customers in its original service territory from 1999 to 2009, though 20% of PPL's retail customers would be randomly assigned to a POLR supplier other than PPL. *Id.* at 276.

155. Borough of Olyphant v. PP&L, No. 03-40232004, U.S. Dist. LEXIS 8958 (E.D. Pa. May 14, 2004), *aff'd*, 153 Fed. App'x 80 (3d Cir. 2005).

156. *Borough of Lansdale*, 426 F. Supp. 2d at 276.

157. *Id. at* 277.

158. *Borough of Lansdale*, 426 F. Supp. 2d at 279. Moreover, the court emphasized that three of the parties to the Joint Petition were Pennsylvania administrative agencies, namely, Pennsylvania's Office of Consumer Advocate, Office of Small Business Advocate, and Office of Trial Staff. *Id.*

159. Borough of Lansdale v. PP&L, Inc., 426 F. Supp. 2d 264, 283-85 (E.D. Pa. 2006). Plaintiffs alleged that a price squeeze resulted from the combined effect of the fixed, retail POLR rates under the Joint Petition and a separate wholesale power supply agreement filed with the FERC, whose rates allegedly increased each year. In rejecting the monopolization claim, the court relied on a previous Third Circuit decision in Utilimax.com, Inc. v. PPL Energy Plus LLC, 273 F. Supp. 2d 573, 584-86 (E.D. Pa. 2003), *aff'd*, 378 F.3d 303 (3d Cir. 2004), in which it held that the PJM ICAP rates, "'though allegedly excessive, were the result of PPL's temporary [monopoly] position in the wholesale capacity market that was established and approved by FERC and PJM." *Borough of Lansdale*, 426 F. Supp. 2d at 284 (quoting *Utilimax.com*, 378 F.3d at 306).

level.[160] Similarly, the court rejected their arguments that their claims implicated the non-rate exception to the filed rate doctrine because their claims in fact involved rate-based activities, namely, a price squeeze implicating FERC-approved wholesale rates and allegedly excessive ICAP rates.[161]

Finally, the court dismissed plaintiffs' price discrimination claims under section 2 of the Clayton Act because they were premised on the fact that PPL subsidiaries were allegedly given preferential treatment. As in *Olyphant*, the court held that "intra-corporate transfers" between parent and subsidiary could not form the basis for the Clayton Act claims.[162]

E. Public Utilities Commission of the State of California v. FERC

In *Public Utilities Commission of the State of California v. FERC*,[163] the U.S. Court of Appeals for the Ninth Circuit significantly expanded the scope of transactions to be included in the California refund proceedings, extending beyond the parameters originally established by the FERC. In addition to preserving the scope of the existing refund proceedings for the FERC-jurisdictional sellers,[164] the court held that these proceedings should be expanded to include: (1) tariff violations that occurred prior to October 2, 2000; (2) forward transactions in the California Power Exchange (CalPX) and California Independent System Operator (Cal-ISO) markets that occurred outside the twenty-four hour period specified by the FERC; and (3) energy exchange transactions in the CalPX and Cal-ISO markets.[165]

The court upheld the FERC order establishing a refund effective date under section 206 of the FPA of October 2, 2000, i.e., sixty days after San Diego Gas & Electric's (SDG&E) August 2, 2006, complaint against sellers to the CalPX and Cal-ISO markets. However, the court held that the FERC erred by refusing to grant relief for tariff violations that occurred prior to the refund effective date under section 309 of the FPA because, unlike proceedings under section 206 of the FPA, no time limits apply to section 309 remedial actions.[166] The court rejected the FERC's argument that there was no evidence of tariff violations prior to the refund effective date as contrary to the FERC's findings in various enforcement proceedings,[167] and because the California Parties had "presented

160. *Borough of Lansdale*, 426 F. Supp. 2d at 286-87.

161. *Id.* at 287 (discussing *In re* Lower Lake Erie Iron Ore Antitrust Litig., 998 F.2d 1144 (3d Cir. 1993)).

162. *Borough of Lansdale*, 426 F. Supp. 2d at 291-92.

163. California Pub. Util.. Comm'n v. FERC, 456 F.3d 1025 (9th Cir. 2006).

164. The court affirmed the FERC's determination that the following types of transactions should be included in the scope of the California refund proceedings: (1) out-of-market sales to the Cal-ISO for load balancing; (2) sales made during non-emergency hours when power supply was sufficient to meet demand; (3) sleeve sales in which the seller was actually an intermediary between the CalPX or Cal-ISO and another seller who could not or would not transact directly with the CalPX or Cal-ISO due to credit concerns. The court also affirmed the FERC's decision to exclude long-term bilateral sales to the California Department of Water Resources, finding that these sales were not properly at issue because these proceedings were limited to sales to the CalPX and Cal-ISO. *Id.* at 1063.

165. *California Pub. Util. Comm'n*, 456 F.3d at 1033.

166. *Id.* at 1025.

167. *California Pub. Util. Comm'n*, 456 F.3d at 1047.

significant evidence of pervasive tariff violations during the pre-Refund Period."[168]

The court also rejected the FERC's decision to limit refund proceedings to spot market sales and its exclusion of exchange sales. It found that the FERC had misconstrued the original SDG&E complaint to be limited to spot market transactions and that the FERC had failed to explain its continued exclusion of forward transactions in light of the additional evidence offered by the California Parties that sellers had manipulated these markets.[169] The court further found that the FERC abandoned its duty under the FPA to ensure just and reasonable rates when it excluded exchange sales due to the difficulty in calculating refund liability for transactions that the FERC could not assign a monetary value.[170]

F. Bonneville Power Administration v. FERC

In *Bonneville Power Administration v. FERC*,[171] the U.S. Court of Appeals for the Ninth Circuit held that the FERC does not have refund jurisdiction under section 206 of the FPA with respect to governmental entities and non-public utilities, and consequently that these entities must be excluded from any potential refund liability in the California refund proceedings.[172] According to the court, the main question at issue was whether the FERC's refund authority is based upon the identities of the sellers (i.e., public versus non-public utilities) or the nature of the transactions (i.e., the FERC's broad regulatory authority over the sale of electric energy for resale in interstate commerce).[173] The court determined that the sellers' identities are the paramount consideration. According to the court, section 201(f) of the FPA provides that no provision in Part II of the FPA applies to governmental entities unless expressly specified. Sections 205 and 206 of the FPA are the only provisions authorizing the FERC to order refunds of unjust and unreasonable rates, and these sections apply only to rates charged by a "public utility."[174] The court further emphasized that the FERC's prior controlling interpretation of these sections is that such governmental entities are not public utilities and thus are not subject to refund liability under section 206 of the FPA.[175]

The court rejected the FERC's theory that its general subject matter jurisdiction over electricity sales at wholesale under section 201(b)(1) of the FPA gives it jurisdiction to order refunds by non-public utilities despite the express limitations in sections 201(f), 205, and 206 of the FPA. As a matter of statutory construction, such specific limitations prevail over general grants of regulatory authority. The court thus concluded that the text and structure of the FPA unambiguously exclude such governmental entities from the FERC's refund authority and that the FERC's contrary construction of the FPA is not

168. *Id.*

169. California Pub. Util. Comm'n v. FERC, 456 F.3d 1025, 1057-60 (9th Cir. 2006).

170. *Id.* at 77-83.

171. Bonneville Power Admin. V. FERC, 422 F.3d 908 (9th Cir. 2005).

172. *Id.* at 911-12.

173. *Bonneville Power Admin.*, 422 F.3d at 911.

174. *Id.* at 918.

175. *Bonneville Power Admin.*, 422 F.3d at 921-22.

owed *Chevron* deference.[176] Finally, the court rejected the FERC's theory that it acquired refund jurisdiction by waiver or agreement of the parties because regulatory jurisdiction can be conferred only by Congress, not by a seller's agreement, waiver, or voluntary participation in FERC-regulated markets.[177]

G. *Texaco Inc. v. Dagher*

In *Texaco Inc. v. Dagher*,[178] the Supreme Court reversed a decision by the Court of Appeals for the Ninth Circuit, which held that Texaco, Inc. (Texaco) and Shell Oil Co. (Shell) engaged in horizontal price fixing because Equilon, a joint venture they had formed to refine and sell gasoline, charged a single, unified price for both of their respective brands of gasoline.[179]

The court emphasized that Texaco and Shell were not competitors in the relevant market (i.e., the sale of gasoline to service stations in the Western United States), but rather participated jointly in that market solely in their capacity as shareholders of Equilon.[180] The joint venture's pricing policy thus was not a *per se* unlawful pricing agreement between competitors. Instead, the court found that Equilon was a legitimate, economically-integrated joint venture. Consequently, Equilon, like any other firm, has "the discretion to sell a product under two different brands at a single, unified price."[181] The court also rejected the Ninth Circuit's reliance on the ancillary restraints doctrine (which applies to the restrictions imposed by a joint venture's "nonventure" activities) because the price-setting activities challenged here were a core activity of the joint venture.[182]

H. *Phelps Dodge Corp. v. El Paso Corp.*

In *Phelps Dodge Corp., et al. v. El Paso Corp.*,[183] the Arizona Court of Appeals affirmed the dismissal with prejudice of a state law antitrust complaint filed by Phelps Dodge Corporation and its subsidiaries against El Paso Corporation and its subsidiaries, including El Paso Natural Gas Company (EPNG). The complaint claimed EPNG withheld capacity from Phelps Dodge and other customers in 2000-2001, based on claims arising out of the California energy crisis during that period. According to the court, the trial court lacked jurisdiction over the complaint, which collaterally attacked the FERC and D.C. Circuit rulings rejecting the same claims.

Specifically, the court found that Phelps Dodge's complaint indirectly challenged several FERC orders which, among other things, required Phelps Dodge to convert from full requirements (FR) to contract demand service, and rejected various claims by Phelps Dodge that EPNG had breached its service

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176. *Id.* at 920 (citing Chevron U.S.A., Inc. v. Natural Res. Defense Council, Inc., 467 U.S. 837 (1984).

177. Bonneville Power Admin. V. FERC, 422 F.3d 908 (9th Cir. 2005).

178. Texaco Inc. v. Dagher, 126 S.Ct. 1276 (2006).

179. The court noted that the joint venture was approved in an FTC consent decree, subject to certain divestments. *Id.* at 1279 (citing *In re* Shell Oil, 125 F.T.C. 769 (1998)).

180. *Texaco*, 126 S. Ct. at 1280.

181. *Id.*

182. *Texaco*, 126 S. Ct. at 1281.

183. Phelps Dodge Corp. v. El Paso Corp., 142 P.3d 708 (Ariz. Ct. App. 2006).

obligations by curtailing shippers during periods of high demand in 2000-2001 prior to the FR conversion. According to the court, in *Arizona Corp. Commission v. FERC*,[184] the D.C. Circuit affirmed the FERC's rulings as follows: "[n]or do petitioners persuade us that El Paso improperly withheld capacity. The FERC observed, and petitioners did not disprove, that El Paso operated its 'dynamic' pipelines at reasonable levels of capacity."[185] The court noted that section 19(b) of the Natural Gas Act precludes "*de novo* litigation between the parties of *all issues inhering in the controversy*."[186] Applying this principle, the court found that although Phelps Dodge had filed claims based on state antitrust law, its claims constituted an indirect challenge to the earlier FERC decision that had already been affirmed by the D.C. Circuit.[187] The issues of capacity and the alleged improper withholding of it—issues that were central to Phelps Dodge's antitrust complaint—were "inhering in the controversy," and had been "specifically addressed and rejected on the merits" at the FERC and in the D.C. Circuit.[188] The court thus concluded that Phelps Dodge's claims constituted a collateral attack on the FERC's prior orders, which could only be challenged by filing a petition for review with the appropriate federal court of appeals under section 19(b) of the NGA.[189] Accordingly, the court ruled that the state trial court had lacked subject matter jurisdiction to hear Phelps Dodge's claims.

184. Arizona Corp. Comm'n v. FERC, 397 F.3d 952, 955 (D.C. Cir. 2005).

185. *Phelps Dodge Corp.*, 142 P.3d at 711 (quoting *Arizona Corp. Comm'n*, 397 F.3d at 955).

186. *Id.* (quoting Williams Natural Gas Co. v. City of Okla. City, 890 F.2d 255, 262 (10th Cir. 1989)).

187. *Phelps Dodge Corp.*, 142 P.3d at 712.

188. *Southwest Ctr. For Biological Diversity*, 967 F.Supp. at 712.

189. *Id.*

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