REPORT OF THE COMPETITION & ANTITRUST COMMITTEE

This report summarizes antitrust and competition developments of particular interest to energy law practitioners that occurred in 2009.* The topics are covered in the following order:

I. BACKGROUND AND ORDER NO. 697

The Federal Energy Regulatory Commission (FERC or Commission) has actively addressed market-based rates between 2007 and the present. Beginning

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with the issuance of Order No. 697 in 2007, the FERC has amended and revised its market-based rate regulations and policies for public utilities by addressing issues relating to horizontal market power, vertical market power, affiliate abuse, and market power mitigation.[1]

With regard to horizontal market power, in Order No. 697, the Commission adopted two screens that serve as a rebuttable presumption of market power if, during a market power analysis, either screen fails.[2] Additionally, the Commission adopted a fact-specific test for control over generation capacity.[3]

Adding to its existing vertical market power analysis, the Commission affirmed its authority to revoke market-based rates upon finding a connection between specific facts relating to an Open Access Transmission Tariff (OATT) violation and a seller's market based-rate authority.[4] Further, pursuant to Order No. 697, the Commission will consider a seller's ability to erect barriers to entry in determining whether an entity possesses vertical market power.[5]

In Order No. 697, the Commission also incorporated affiliate restrictions, which must be complied with on an ongoing basis, if an entity wishes to obtain and retain market-based rate authority.[6] Restrictions are designed to prevent affiliate abuse, and the Commission expressed that the restrictions are to be applied in a manner that is consistent with the FERC's Standards of Conduct. Finally, the Commission retained its existing default market power mitigation methodologies applied to public utilities sellers who fail either of the market power screens.[7]

In 2008, the Commission issued orders enhancing and clarifying Order No. 697. In Order No. 697-A, the Commission established a rebuttable presumption that the existing RTO/ISO mitigation analyses are sufficient to address horizontal market power concerns within the RTO/ISO market, even if a seller fails one or both of the Commission's horizontal market power screens.[8] An intervenor, however, may challenge this presumption and the Commission will investigate whether the RTO/ISO mitigation continues to be just and reasonable.[9] Order No. 697-A also adopted the definition of affiliate

1. Order No. 697, *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 72 Fed. Reg. 39,904, 119 F.E.R.C. ¶ 61,295 (July 20, 2007), *clarified*, 121 F.E.R.C. ¶ 61,260 (2007), *order on reh'g*, Order No. 697-A, 73 Fed. Reg. 25,832, 123 F.E.R.C. ¶ 61,055 (May 7, 2008) (Order No. 697-A), *clarified*, 124 F.E.R.C. ¶ 61,055 (2008), *order on reh'g*, Order No. 697-B, 73 Fed. Reg. 79,610, 125 F.E.R.C. ¶ 61,326 (Dec. 30, 2008) (Order No. 697-B), *order on reh'g*, Order No. 697-C, 74 Fed. Reg. 30,924, 127 F.E.R.C. ¶ 61,284 (Jun. 29, 2009) (Order No. 697-C).

2. *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 119 F.E.R.C. ¶ 61,295 at P 13 (2007).

3. *Id.* at P 14.

4. *Id.* at P 21.

5. *Id.* at P 22.

6. *Id.* at P 23.

7. *Id.* at P 604 (promulgating the default mitigations as: 1) incremental cost plus 10 percent for sales of one week or less; 2) embedded cost "up to" rate reflecting the costs of the units expected to provide the service for sales between greater than one week and less than one year; and 3) rate not to exceed the embedded cost of service for sales of power one year or greater).

8. *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 123 F.E.R.C. ¶ 61,055 at P 5, 110 (2008).

9. *Id.*

promulgated in the Affiliate Transactions Final Rule,[10] and clarified that the affiliate restrictions set forth in Order No. 697 supersedes the codes of conduct approved prior to the effective date of Order No. 697.[11]

In Order No. 697-B, the Commission further clarified Order No. 697-A by requiring market-based rate sellers to consider imports of their own and affiliated generation from adjacent markets when conducting their horizontal market power analysis.[12] Also, Order No. 697-B revised the Commission's definition for affiliate by eliminating a separate definition for exempt wholesale generators.[13]

A. 2009 Update and Order No. 697-C

2009 opened with Tampa Electric Company seeking an extension of time to comply with the revised mitigated sales tariff provision that was established in Order 697-B, to which the Commission granted an extension until the issuance of an order on rehearing.[14] The Commission also mandated that entities affected by the matter must comply with the mitigated sales tariff provision in Order No. 697-A until a determination is made.[15] On June 29, 2009, the Commission issued Order No. 697-C, which denied a rehearing and affirmed Order No. 697-B's revised mitigated sales tariff.[16]

Order No. 697-C, as well as other Commission orders in 2009, further amended and clarified its market-based rate policy as originated in Order No. 697. In particular, the continued focus remained on market power and affiliate issues.

B. Market Power Developments for 2009

With regard to market power issues, Order No. 697-C amended its reporting requirements by requiring quarterly reporting of a seller's acquisition of a site or

10. *Id.* at P 9 (*citing* Order No. 707, *Cross-Subsidization Restrictions on Affiliate Transactions*, 122 F.E.R.C. ¶ 61,155 (2008) defining affiliate restrictions to include "power sales and transactions for nonpower goods and services between franchised public utilities that have captive customers or that own or provide transmission service over jurisdictional transmission facilities, and their market-regulated and non-utility affiliates").

11. *Id.* at P 10.

12. *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 125 F.E.R.C. ¶ 61,326 at P 6 (2008).

13. *Id.* at 48 (*amending* 17 C.F.R. § 35.36(a)(9), defining affiliate as:

> (a) Any person that directly or indirectly owns, controls, or holds with power to vote, 10 percent or more of the outstanding voting securities of the specified company; (b) Any company 10 percent or more of whose outstanding voting securities are owned, controlled, or held with power to vote, directly or indirectly, by the specified company; (c) Any person or class of persons that the Commission determines, after appropriate notice and opportunity for hearing, to stand in such relation to the specified company that there is liable to be an absence of arm's-length bargaining in transactions between them as to make it necessary or appropriate in the public interest or for the protection of investors or consumers that the person be treated as an affiliate; and (d) Any person that is under common control with the specified company).

14. *Market-Based Rates for Wholesale Sales of Electric Energy*, 126 F.E.R.C. ¶ 61,072 at P 2 (2009).

15. *Id.*

16. *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 127 F.E.R.C. ¶ 61,284 at P 1 (2009).

sites for new generation capacity development.[17] The purpose of these quarterly reports is to give an opportunity to interested parties to intervene and comment on the acquisitions of sites for new generation capacity if they believe the acquisition will create barriers to market entry.[18] In particular, these quarterly reports apply to sites for which "site control"[19] has been found in the interconnection process and for which the potential megawatts that are commercially feasible on the site equals or exceeds 100 megawatts.[20] Also, under this new quarterly reporting obligation, the timing has been extended from submission within thirty days of an acquisition to within thirty days after the end of each quarter for which an acquisition related change in market-based rate status occurs.[21] Each report shall include: a) the number of sites acquired or to be acquired; b) the geographic market where the sites are located; and c) a justification of "the maximum potential number of megawatts that are reasonably commercially feasible on the sites reported . . . ."[22] Finally, the Commission created a separate reporting requirement for land acquired without demonstration of site control because the Commission is concerned that the purpose of such acquisitions is to prevent development of new generation capacity, thereby creating further barriers to entry and bolstering an existing seller's market power.[23]

Order No. 697-C also revised the mitigated sales tariff provision to mandate that "if the Seller sells at the metered boundary of a mitigated balancing authority area at market-based rates, then neither it nor its affiliates can sell into that mitigated balancing area [authority] from the outside."[24] The purpose of this revision is to ensure that a mitigated seller, or its affiliates, does not sell into the mitigated market through market-based rate sales at the metered boundary.[25] The metered boundary is the area "between a balancing authority area in which a seller is found, or presumed, to have market power and a balancing authority area in which the seller has market-based rate authority . . . ."[26] This revision derives from the general rule that mitigated sellers are prohibited from selling market-based rate power in their balancing authority area where the seller is

17. *Id.* at P 18 (amending 18 C.F.R. § 35.42 (2009)).

18. *Id.* at P 17.

19. *Standardization of Generator Interconnection Agreements and Procedures*, 104 F.E.R.C. ¶ 61,103 P 40 (2003) (referring to Standard Large Generator Interconnection Procedures § 1:

> "Site control" is documentation reasonably demonstrating: 1) ownership of a leasehold interest in a site, or the right to develop a site; 2) an option to acquire a leasehold site; or 3) "an exclusivity or other business relationship between Interconnection Customer and the entity having right to sell, lease or grant Interconnection Customer the right to possess or occupy the site for such purpose).

20. *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 127 F.E.R.C. ¶ 61,284 at P 18 (2009).

21. *Id.*

22. *Id.* at P 19.

23. *Id.* at P 20 (amending 18 C.F.R. § 35.42, requiring this report to be made upon a triggering event which: "site control has not yet been demonstrated . . . during the prior three years . . . and for which the potential number of megawatts that are reasonably commercially feasible on the land for new generation capacity development is equal to 100 megawatts or more").

24. *Id.* at P 42; *Id.* at P 24.

25. *Id.* at P 42.

26. *Id.* at P 23.

found, or presumed by a market power screen, to have market power.[27] As an alternative, the Commission advised mitigated sellers who wish to eliminate the risk that they will resell such power back into the mitigated area to not sell at market-based rates for sales within the metered boundary.[28] Likewise, such a risk could be mitigated by limiting sales at the metered boundary to end-users.[29]

Finally, on November 19, 2009, the Commission issued an order clarifying the issue of company control over facilities owned by another company, for which control is to be construed broadly for market power purposes.[30] In *Entegra Power*, a hedge fund filed an application with the Commission under Section 203 of the Federal Power Act (FPA) to acquire between ten and twenty percent of Entegra Power's outstanding voting securities.[31] The Commission approved the transaction, which included jurisdictional facilities like generator-interconnection facilities, wholesale power contracts, and rate schedules.[32] Calpine protested the transaction because the hedge fund owned twenty-one percent of Calpine common stock with the option to acquire up to forty percent of the common shares.[33] As such, Calpine was concerned that the acquisition by the hedge fund would jeopardize its ability to make market-based rate sales in the Entergy balancing authority area, and so Calpine argued that the hedge fund should not be considered to control Calpine in a horizontal market power analysis.[34] The Commission rejected Calpine's argument, and in approving the transaction, placed restrictions on the hedge fund's ability to exercise control over Entegra, thus mitigating the risk of horizontal market power concentration.[35]

Calpine petitioned for rehearing arguing that the hedge fund cannot be said to control Calpine for horizontal market power analysis since the hedge fund has no ability to control the power price from which power is sold by Calpine.[36] The Commission denied rehearing and clarified that control does not merely apply to daily operations of jurisdictional facilities, like in the ability to control the day-to-day sales of wholesale power.[37] As such, the Commission rejected this narrow view of control and took a broad view based on the "totality of the circumstances on a fact-specific basis."[38] Since the hedge fund could exercise corporate control over Calpine through its option to acquire up to forty percent of the common shares, and in other similar circumstances that hedge fund has exercised such an option, the Commission deemed the hedge fund controls Calpine for the purpose of market power analysis.[39]

27. *Id.*
28. *Id.*
29. *Id.*
30. *Entegra Power Group*, L.L.C., 125 F.E.R.C. ¶ 61,143 (2008) [hereinafter *Entegra Power I*], *reh'g denied*, 129 F.E.R.C. ¶ 61,156, P 19 (2009) [hereinafter *Entegra Power II*].
31. *Entegra Power I*, *supra* note 30, at P 1.
32. *Id.*
33. *Id.* at P 16-17.
34. *Id.*
35. *Id.* at P 40.
36. *Entegra Power II*, *supra* note 30, at P 5.
37. *Id.* at P 19.
38. *Id.*
39. *Id.* at P 20.

C. 2009 Affiliate Sales Developments

On January 21, 2009, the Public Utilities Commission of Ohio (Ohio Commission) requested a rehearing of a prior order which granted First Energy affiliates a permanent waiver of the affiliate sales restrictions promulgated in Order No. 697.[40] The Ohio Commission argued that the permanent waiver creates a risk that First Energy's wholesale rates charged to regulated utilities in Ohio will be unjust and unreasonable, and as such, the permanent waiver is unwarranted.[41] The Ohio Commission denied rehearing, reasoning that retail choice states like Ohio do not have captive customers in need of protection by affiliate restrictions.[42] A captive customer is defined as "any wholesale or retail electric energy customers served by a franchised public utility under cost-based regulation."[43] As such, customers in retail choice states are not served by a franchised utility under cost-based regulation.[44] And even if the Ohio retail customers met the definition of captive customers, the Commission found that affiliate abuse is not a concern with respect to First Energy affiliates since Ohio state law provides sufficient protection in its procurement process to prevent affiliate abuse.[45]

D. Order 719-A: Wholesale Competition in Regions with Organized Electric Markets, Order on Rehearing

The 2009 Report of the Antitrust and Competition Committee reported on FERC Order No. 719.[46] Issued on October 17, 2008, Order No. 719 adopted measures respecting demand response and market pricing during periods of operating reserve shortage, long-term power contracting, market monitoring policies, and the responsiveness of ISOs and RTOs to stakeholders and customers.

On July 16, 2009, the Commission issued Order No. 719-A.[47] In its order on rehearing the Commission largely affirmed its determinations in Order No. 719, while denying in part and granting in part rehearing and clarification regarding certain elements of its earlier order. On December 17, 2009, the Commission issued Order No. 719-B, a further Order Denying Rehearing and Providing Clarification.[48]

On the first issue addressed in Order No. 719-A, the Commission rejected a challenge to its authority to establish rules respecting demand response and demand response aggregators; rejected arguments that Order 719 impinges on state jurisdiction and imposes burdens on small entities in violation of the Regulatory Flexibility Act of 1980 by requiring public power systems and

40. *First Energy Solutions Corp*., 125 F.E.R.C. ¶ 61,356 (2008), *reh'g denied*, 128 F.E.R.C. ¶ 61,119 at P 1, 6 (2009).

41. *First Energy Solutions*, 128 F.E.R.C. ¶ 61,119 at P 7.

42. *Id.* at P 16.

43. *Id.* (*quoting* 18 C.F.R. § 35.36(a)(6) (2008)).

44. *Id.*

45. *Id.* at P 19-20.

46. *Wholesale Competition in Regions with Organized Markets*, 125 F.E.R.C. ¶ 61,071 (2008).

47. *Wholesale Competition in Regions with Organized Markets*, 128 F.E.R.C. ¶ 61,059 (2009) [hereinafter *Order No. 719-A*].

48. *Wholesale Competition in Regions with Organized Markets*, 129 F.E.R.C. ¶ 61,252 (2009).

cooperatives to take affirmative action to consider retail aggregation issues; and denied that Order 719 undermines either existing retail demand response programs or Load Serving Entities' (LSEs) existing rates, metering, and billing protocols.

With respect to its jurisdiction, the Commission explained that it has "broad authority under the FPA to identify practices that 'affect' public utility wholesale rates under the FPA."[49] Explaining that "demand response affects wholesale markets, rates, and practices,"[50] the Commission likened Order 719's provisions promoting demand response in organized markets to the ISO New England installed capacity requirement approved by the D.C. Circuit earlier in 2009.[51]

In response to claims that Order No. 719 interfered with state authority, the Commission explained that Order No. 719's demand response provisions applied only to the organized markets under the Commission's jurisdiction. The Final Rule, the Commission stated "did not challenge the role of states and others to decide the eligibility of retail customers to provide demand response."[52] Nor did the Commission "intend to make findings as to whether ARCs may do business under state or local laws, or whether ARCs' contracts with retail customers are subject to state and local law. Nothing in the Final Rule authorizes a retail customer to violate existing state laws or regulations or contract rights."[53] To minimize the concerns of small entities, the Commission directed the organized markets to amend their market rules to require affirmative permission from the relevant electric retail regulatory authority before accepting bids from ARCs that aggregate the demand response of small electric utilities.[54] The Commission also required each RTO or ISO, through the stakeholder process to develop appropriate mechanisms for sharing information to address utilities' concerns about the impacts that RTO demand response programs could have on their operations.[55]

With respect to the second element of Order No. 719, the Commission rejected several challenges to the Commission's shortage pricing requirements. Parties had argued that the proposal would eliminate price caps during periods when bidders could exercise market power; that customers do not have in place tools to enable them to respond to scarcity prices; and, that the Commission acted without sufficient evidence that its proposal would achieve its goals, including achieving just and reasonable wholesale power prices, encouraging investment in new generation resources, and encouraging investment in new demand response resources.[56] The Commission also declined to adopt several alternative scarcity pricing proposals that would have permitted demand response resources to receive higher prices without raising bid caps for generation resources.

49. *Order No. 719-A*, *supra* note 47, at P 45.

50. *Id.* at P 46.

51. *Id.* at P 45 (*citing* Connecticut Dep't of Public Util. Control v. FERC, No. 07-1375, slip op. at 14-15 (D.C. Cir. June 23, 2009)).

52. *Id.* at P 49.

53. *Id.* at P 54.

54. *Id.* at PP 51, 59.

55. *Id.* at P 69.

56. *Id.* at P 74.

The Commission reaffirmed its determination in Order No. 719 that "today's RTO and ISO market rules may not produce rates that accurately reflect the true value of energy during periods of operating reserve shortages. . ." and that "such inaccurate prices during an emergency may harm reliability, inhibit demand response, deter new entry of demand response and generation resources, and thwart innovation."[57] In response to evidence submitted by parties demonstrating that scarcity pricing is unlikely to do more than clear the market in the short term, the Commission responded that "it is reasonable to expect that higher shortage prices will encourage investment in additional generation and demand response resources"[58] and that "[w]ith improved price signals, more buyers would find it worthwhile to invest in technologies that allow them to respond to prices."[59] The Commission dismissed challenges to the efficacy and lawfulness of its proposed scarcity pricing mechanisms, and declined to consider alternative mechanisms by noting that "the Final Rule did not establish the shortage rates to be implemented, or even one particular approach to shortage pricing. . . . Rather, it required RTOs and ISOs to make a compliance filing, in consultation with their customers and other stakeholders."[60] Most of the critiques filed in response to Order No. 719, the Commission asserted should be raised instead in the RTO and ISO stakeholder processes or in response to specific compliance filings.[61]

No parties to the rulemaking objected to the third element of Order No. 719, which promoted long-term power contracting in organized markets by directing RTOs and ISOs to dedicate a portion of their web sites for market participants to post offers to buy and sell electric energy on a long-term basis. Some parties, however, argued that the Commission had an obligation to go further than it did. One group of commenters in particular argued that the Commission "erroneously failed to expand the scope of [the] proceeding to investigate the issues of whether RTO markets are producing just and reasonable rates. They argue[d] that sections 205 and 206 of the Federal Power Act require the Commission to act when it finds evidence of unjust and unreasonable rates."[62] Citing *Massachusetts v. EPA*,[63] this group argued that the Commission had a legal obligation to investigate evidence they submitted of systemic, market-wide failures that "include fewer and higher-priced long-term power supply options, the shifting of financial risks to customers, and impediments to the construction of new generation resources."[64]

Commenters also referred for support to a 2008 GAO Report, "which they argue found that the Commission has not done the analyses necessary to support its assertions that RTO markets provide demonstrable benefits to wholesale customers and consumers."[65] The Commission responded that it has "broad

57. *Id.* at P 94.
58. *Id.* at P 96.
59. *Id.* at P 98.
60. *Id.* at P 103.
61. *Id.* at PP 103-106.
62. *Id.* at P 112.
63. 549 U.S. 497 (2007).
64. *Order No. 719-A*, *supra* note 47, at P 113-114.
65. *Id.* at P 115.

discretion to choose how best to marshal its limited resources and personnel to carry out its designated responsibilities,"[66] that the Commission had properly limited the Final Rule to "incremental improvements to the ongoing operation of organized markets without undoing or upsetting the significant efforts that have already been made in providing demonstrable benefits to wholesale customers,"[67] and that the Commission "welcome[s] suggestions for concrete actions that could be taken to improve competition in wholesale markets."[68]

The fourth element of Order No. 719 included a number of reforms designed to enhance the market monitoring function. Despite a large number of requests for rehearing and clarification on different elements of the Final Rule, the Commission modified only one element of this portion of the Order. The Commission decided to "permit an RTO or ISO MMU to enter into contracts to monitor a market participant operating in the same RTO or ISO for activity in that RTO or ISO, under limited conditions."[69]

E. Control and Affiliation for Purposes of Market-Based Rate Requirements Under Section 205 of the Federal Power Act and Requirements of Section 203 of the Federal Power Act (FERC Docket No. PL09-3)

In September 2008, the Electric Power Supply Association (EPSA) filed a petition with the Commission in Docket No. EL08-37 requesting guidance with respect to the question of when investments in publicly-held companies will be deemed to convey "control" or to result in "affiliation" for purposes of the Commission's market-based rate requirements of section 205 of the FPA and the requirements of section 203 of the FPA.[70]

More specifically, EPSA asked the FERC for three determinations. First, it asked the FERC to establish that investments in publicly-held companies by investors owning less than twenty percent of such companies' voting securities and making filings with the Securities and Exchange Commission (SEC) on SEC Schedule 13G, certifying that the investment is not for the purpose of controlling the company, will not be deemed to convey "control" or to result in "affiliation" for market-based rate or FPA section 203 purposes.[71] Second, EPSA sought confirmation that Commission findings that a given entity does not "control" another entity made in the FPA section 203 setting apply equally in the market-based rate setting to affected market-based rate sellers.[72] Finally, EPSA requested the FERC to state that investments by entities upstream of a publicly-held company in entities not otherwise related to the publicly-held company will not be deemed to be within the knowledge and control of the publicly-held company's subsidiaries with market-based rate authorization, and, therefore, those market-based rate subsidiaries will not be required to file a notification of

66. *Id.* at P 118.

67. *Id.* at P 119.

68. *Id.* at P 121.

69. *Id.* at P 164.

70. ELECTRIC POWER SUPPLY ASS'N, OVERVIEW OF EPSA ANSWER TO PROTESTS FILED ON PETITION FOR GUIDANCE REGARDING COMPANY CONTROL AND AFFILIATION (2008), *available at* http://www.epsa.org/forms/uploadFiles/D9DB000000A1.filename.FYI9_Fact_Sheet_re_Control_and_Affiliation_Response.pdf.

71. *Id.*

72. *Id.*

change in status or to include generation or inputs to generation owned or controlled by the other entities in future market power analyses.[73]

The petition was initially given Docket No. EL08-37, but, finding that the petition raised "issues of generic implication to the electric utility industry,"[74] the FERC opened a new docket of general applicability, Docket No. PL09-3 and announced that it would hold a workshop in December 2009.[75] It asked parties interested in participating in the workshop to address, among other things, (1) whether the FERC should reconsider its decision in *FPA Section 203 Supplemental Policy Statement*, 120 FERC ¶ 61,060 (2007) not to rely solely on a Schedule 13G filing as evidence of a lack of control and instead to consider the totality of the facts and circumstances on a case-by-case basis, (2) how compliance with the intent not to exercise control for purposes Schedule 13G would address the Commission's concerns under section 203 of the FPA and the Commission's market-based rate program under FPA sections 205 and 206 and whether the statutory and policy purposes of Schedule 13G filings were comparable to the purposes of FPA sections 203, 205, and 206 and (3) what types of actions an investor could take with respect to a company's management, operations and policy and still be eligible to file a Schedule 13G?

In response to the FERC's invitation a number of parties participated in the December workshop and submitted post-workshop written comments in early 2009. Those participating included financial institutions, power marketers, municipal utilities and rural electric cooperatives, and the American Antitrust Institute.

F. Power Supplier Comments

Representative of the comments submitted by power marketers were those of the Mirant companies, who generally supported EPSA's petition. Mirant questioned the Commission's current policy in section 203 proceedings, commenting that under existing policy a utility, along with any other market-based rate sellers in which the acquiring investor owns an interest, could be deemed to be under common control, and hence "affiliates" pursuant to section 205, requiring each one of them to account for the others' generation when justifying their respective eligibility to sell at market-based rates. This, Mirant stated, appeared to be an unintended and unwarranted consequence of FERC's current section 203 policy, at least where the investment is passive and confers no meaningful control over the market-based rate seller's operations. To address its concern, Mirant proposed that where an acquirer of public utility stock demonstrates that it cannot or will not control a public utility, the Commission, in its section 203 order, should make an express finding of absence of control on the part of the acquirer and should allow the utility to rely on that finding for purposes of its market-based rate authorization and compliance obligations. As

73. *Id.*

74. Notice Redocketing Proceeding, Electric Power Supply Association, Control and Affiliation for Purposes of Market-Based Rate Requirements Under Section 205 of the Federal Power Act and the Requirements of Section 203 of the Federal Power Act, 73 Fed. Reg. 67,152 (Nov. 12, 2008).

75. Notice of Agenda for Workshop, Control and Affiliation for Purposes of the Commission's Market-Based Rate Requirements Under Section 205 of the Federal Power Act and the Requirements of Section 203 of the Federal Power Act, 73 Fed. Reg. 72,783-72,784 (Nov. 21, 2008).

to what constitutes a determination of "control," it suggested that where an acquirer commits that its acquisition is being made for investment purposes and that it will not exercise control over the management or policies of the utility, the Commission should make an unambiguous, express finding that there is no change in control of the utility.

G. American Antitrust Institute Comments

The Antitrust Institute urged the Commission to reject EPSA's proposal that the Commission use SEC Schedule 13G as a criterion for what does not constitute "control" for evaluating competitive issues in section 203 and 205 applications. Section 203 and 205 transactions involving cross-ownership, it stated, often raise complex competitive issues suggesting the need for: "(1) a more robust screening test for transactions that would clearly have a *de minimis* effect on competition and (2) reasoned analysis for those that will not."[76]

The Antitrust Institute's principal stated concern with the EPSA proposal was that ownership share alone, particularly in the case of cross-ownership by private equity firms, is not determinative of the ability to influence a firm's competitive decisions. Private equity transactions, it commented, "are a fundamentally different and novel type of strategy for investment in the electricity sector"[77] in that, unlike the typical section 203 transactions involving complete mergers or acquisitions, these transactions involve acquisition of a partial ownership stake in a company that often adds to an investment portfolio that already includes a partial interest in a rival generating asset. According to the Antitrust Institute, "[p]artial ownership by a private equity firm in competing assets can adversely affect competition in three possible ways:"[78] (1) by controlling or influencing the competitive decisions of the partially-owned firms, (2) by the diminished rivalry between firms that that might result from common ownership and (3) by the "potential exchange of competitively sensitive information between the commonly owned firms—using the private equity firm as a conduit."[79] It said that EPSA's bright line ownership share approach would not adequately address these concerns, which are relevant under FPA sections 203 and 205.[80] As to EPSA's proposal that the FERC rely on Schedule 13G filings, its main objection was that Schedule 13 G has as its primary purpose the protection of investors, not the consumers whose protection is the main purpose of FPA sections 203 and 205.[81]

H. Joint Comments of APPA and NRECA

The American Public Power Association (APPA) and the National Rural Electric Cooperative Association (NRECA) filed joint comments on behalf of

76. Comments of the American Antitrust Institute, Control and Affiliation for Purposes of the Commission's Market-Based Rate Requirements under Section 205 of the Federal Power Act and theRequirements of Section 203 of the Federal Power Act, F.E.R.C. Docket No. PL09-3-000, *available at* http://www.antitrustinstitute.org/archives/files/aaicrossownershipcomments_012020091152.pdf.

77. *Id.*

78. *Id.*

79. *Id.*

80. *Id.*

81. *Id.*

their memberships similar to those filed by the Antitrust Institute. Noting that under current FERC policy, a Schedule 13G filing at the SEC is "probative" evidence of the absence of control, APPA/NRECA's objection was that the EPSA proposal would make such a filing "determinative" of the lack of control by the utility investor. It voiced many of the same concerns as the Antitrust Institute as to why such a test would not adequately measure control or the potential for anticompetitive effect resulting from cross-ownership.

The Commission issued a Notice of Proposed Rulemaking (NOPR) in January 2010 proposing to amend Part 33 of its regulations to grant a blanket authorization under section 203(a)(2) of the FPA and a parallel blanket authorization under section 203(a)(1).[82] Such blanket authorizations would apply to acquisitions representing between ten (equal to or greater than) and twenty percent of the outstanding voting securities of a public utility or holding company. To qualify, the NOPR proposes that the acquiring company file a statement certifying that such securities were not acquired and not to be held for the purpose or effect of changing or influencing the control of the public utility. Finally, the acquiring company must comply with certain conditions designed to limit its ability to exercise control.

II. COMPETITION-RELATED FERC ORDERS

A. *New York Independent System Operator, Inc. (FERC Docket Nos. EC09-32-000, et al.)*

On December 7, 2007, as supplemented on June 18, 2009 and June 27, 2008, pursuant to section 206 of the FPA,[83] the New York Independent System Operator, Inc. (NYISO) submitted a regional transmission planning process as required by Order No. 890.[84] On October 16, 2008, the FERC accepted the NYISO filing with modifications.[85] NYISO and New Transmission Owners (collectively, the Joint Parties), Niagara Mohawk Power Corporation (National Grid), and the New York Regional Interconnect, Inc. (NYRI) filed requests for rehearing. On March 31, 2009, the FERC issued its order on rehearing.

The NYISO plan, which will be known as the Comprehensive System Planning Process (CSPP), consists of two-year cycles which begin with the Local Transmission Planning Process of the New York transmission owners. Each cycle contains three major components: (1) local transmission planning; (2) reliability planning; and (3) economic planning.[86]

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82. *Control and Affiliation for Purposes of Market-Based Rate Requirements under Section 205 of the Federal Power Act and the Requirements of Section 203 of the Federal Power Act*, 130 F.E.R.C. ¶ 61,046 at P 1(2010).

83. 16 U.S.C. § 824(e) (2006).

84. Order No. 890, *Preventing Undue Discrimination and Preference in Transmission Service*, F.E.R.C. STATS. & REGS. ¶ 31,241 (2007), 72 Fed. Reg. 12,266 (Mar. 15, 2007); *order on reh'g*, Order No. 890-A, F.E.R.C. STATS. & REGS. ¶ 31,261 (2007), 73 Fed. Reg. 2984 (Jan. 16, 2008); *order on reh'g*, Order No. 890-B, 123 F.E.R.C. ¶ 61,299 (2008).

85. *New York Independent System Operator, Inc*. 125 F.E.R.C. ¶ 61,068 (2008) [hereinafter *October 16 Order*]; *order on reh'g*, 126 F.E.R.C. ¶ 61,320 (2009) [hereinafter *Rehearing Order*]; *order on reh'g*, 129 F.E.R.C. ¶ 61,045 (2009) [hereinafter *Final Order*].

86. *October 16 Order*, *supra* note 85, at P 7.

The Joint Parties sought clarification or, in the alternative, rehearing of the October 16 Order with respect to the revised Reliability Agreement which NYISO included in its compliance filing.[87] It was not clear to the Joint Parties that FERC had accepted the revised Reliability Agreement. FERC affirmed that it had accepted the revised Reliability Agreement.[88]

The Joint Parties and National Grid sought clarification or, in the alternative, rehearing of the statement in the October 16, 2008 Order that "NYISO continues to bear the ultimate burden of proof, i.e., to demonstrate the justness and reasonableness of the charges resulting from the application of the formula rate" for regulated reliability projects.[89] Under the operating structure, only the transmission-owning utilities and the developers can make rate filings under Rate Schedule 10, and those making the rate filing bear the burden of proof, not the NYISO.[90] The FERC granted rehearing and agreed with the Joint Parties that the burden of proof rests with the entity making the rate filing and found that the language in the October 16 Order was inadvertent.[91]

NYRI sought rehearing or, in the alternative, clarification of NYISO's proposed cost/benefit study. Under the NYISO proposal, the costs of transmission projects for reliability were allocated to load serving entities (LSEs).[92] But economic projects designed to relieve congestion would have costs allocated to LSE only if the projects passed two tests: 1) an economic cost/benefit test, and 2) a voting procedure test. NYRI claimed that the NYISO cost/benefit analysis considered only production cost savings, and did not consider numerous other economic, environmental, and reliability benefits, which would create a bias against economic transmission investment.[93] NYRI stated that reliance on production cost savings alone is an inaccurate measure of project benefits for, among other reasons, it excludes the reduction in customer energy prices, a metric which the FERC has traditionally relied upon. NYRI claimed that NYISO was unique among transmission organizations regarding its reliance solely on production cost savings as the determiner of benefits, FERC denied rehearing. The FERC noted that NYISO's cost/benefit analysis is a two step process.[94] In the first step, the NYISO measures the net system benefits. As the FERC explained in its October 16 Order, production costs savings measures the net system benefits and includes the net benefits to consumers.[95] Hence, NYRI was incorrect that the FERC did not consider price effects.[96] As for other factors, those will be considered in the second step in which beneficiaries vote on the proposed project.[97] Finally, uniqueness of a planning approach does not mean that it is unjust or unreasonable.[98]

87. *Rehearing Order, supra* note 85, at P 12.
88. *Id.* at P 13.
89. *October 16 Order, supra* note 85, at P 94.
90. *Rehearing Order, supra* note 85, at PP 14-15.
91. *Id.* at P 17.
92. *October 16 Order, supra* note 85, at PP 81-88.
93. *Rehearing Order, supra* note 85, at PP 18-19.
94. *Id.* at P 21.
95. *October 16 Order, supra* note 85, at P 110.
96. *Rehearing Order, supra* note 85, at P 26.
97. *Id.* PP 21, 28.
98. *Id.* P 27.

NYRI also sought rehearing on the NYISO supermajority voting procedures for the second step of the cost allocation process.[99] Under the NYISO procedures, eighty percent of the beneficiaries from an economic transmission upgrade, weighted by the benefits received, must vote in favor of the project before it is subject to mandatory cost allocation.[100] NYRI claimed: (1) the procedure would block all congestion-reducing projects;[101] (2) no other RTO had supermajority provisions;[102] (3) the procedure was anticompetitive because some market participants could block a project;[103] (4) the procedure contravenes Congress' mandates in section 216 and 219 of the FPA and FERC Order Nos. 689, 679, and 890.[104] Once again, the FERC denied rehearing. The FERC reasoned that when the costs of an economic transmission project are allocated via the NYISO OATT, the costs and risks of those projects are paid directly by rate payers. In this case,

> the supermajority voting procedure at issue here is a reasonable method of determining which economic transmission project should be subject to OATT cost recovery. We explained that it 'provides a useful check to ensure that a project has net benefits, by requiring that most of those whom NYISO expects to benefit from a project agree that they actually will benefit.'[105]

The voting procedure does not violate prior orders, as Order No. 890-A (at P 252) held that such procedures "could be adopted if stakeholders desire."[106] Similarly, the procedure does not contravene Congress' intent in section 216 and 219 of the FPA.[107] Nor would the procedure be anticompetitive and block transmission projects because southeastern New York LSE had supported merchant transmission projects in the past.[108] Overall, the FERC found that the NYISO economic planning process complements the reliability planning process, as envisioned in Order No. 690.[109]

On April 29, 2009, NYRI filed a request for rehearing of the March 31, 2009 Rehearing Order and a motion to reopen the record. On October 15, 2009, FERC denied NYRI's request for rehearing and dismissed the motion as moot.[110] Rehearing was denied because the FERC does not accept requests for further rehearing when the rehearing order does not change the core ruling of the original order. In this case, the FERC did not change its core ruling and granting rehearing would amount to a second swipe at the same apple.[111] The motion to reopen the record was moot because the document sought to be included in the

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99. *Id.* PP 29-34.

100. *October 16 Order, supra* note 85, at PP 102-103. Projects not receiving a supermajority could proceed as merchant projects with funding from the beneficiaries. *Rehearing Order, supra* note 85, at P 37.

101. *Rehearing Order, supra* note 85, at P 30.

102. *Id.*

103. *Id.* at P 31.

104. *Id.* at PP 32-33.

105. *Id.* at P 35, *citing October 16 Order, supra* note 85, at P 130.

106. *Id.* at P 36.

107. *Id.* at P 41.

108. *Id.* at P 39.

109. *Id.* at P 43.

110. *See generally Final Order, supra* note 85.

111. *Id.* at P 11.

record, NYISO's *Transmission Expansion in New York State* dated November 2008, was already in the record.[112]

B. Exelon Corp/NRG Energy (FERC Docket No. EC09-32-000)

On November 12, 2008, Exelon Corporation (Exelon) commenced an unsolicited tender offer for NRG Energy, Inc. (NRG). On December 18, 2008, Exelon filed an application seeking authorization under section 203 of the FPA for the acquisition of NRG, acquisition of NRG subsidiaries that are public utilities subject to the FERC's jurisdiction, and subsequent restructuring of NRG.[113] Exelon and NRG had two areas with significant overlap of generation assets: PJM East and ERCOT. Exelon proposed a "clean sweep" approach in which it proposed to divest all of NRG's generation assets in PJM East and all of the Exelon generation assets in ERCOT.[114] Exelon also offered to hold harmless transmission customers from rate increases as a result of merger-related costs, and to adopt a number of ring-fencing provisions to prevent any cross-subsidization. NRG, Energy Program of Public Citizen, Inc. (Public Citizen), and the International Brotherhood of Electric Workers (IBEW) filed timely motions to intervene and protest. All three claimed that the application was premature and speculative.[115] NRG had additional objections concerning the proper geographic markets for analysis, the calculation of Available Economic Capacity, the optimal divestiture of assets, and the Commission's jurisdiction over assets in ERCOT.[116] IBEW raised concerns that Exelon would have a higher cost of capital due to lower Exelon credit ratings.[117]

On May 21, 2009, the FERC approved the application as filed by Exelon. The FERC indicated that its task is to review the application as filed, and it concluded that the proposed divestiture were sufficient to ensure no adverse effect on competition.[118] In addition, the FERC found that the acquisition would not increase vertical market power,[119] transmission rates,[120] or cross-subsidization.[121]

After losing a proxy vote for control of NRG, on July 21, 2009, Exelon announced that it was terminating its tender offer. On July 28, 2009, Exelon informed the FERC of its action. No other jurisdictions ruled on the proposed transaction.

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112. *Id.* at P 9.
113. *See generally Exelon Corp*., 127 F.E.R.C. ¶ 61,161 (2009).
114. *Id.* at P 29.
115. *Id.* at PP 21-22.
116. *Id.* at PP 53-58.
117. *Id.* at P 109.
118. *Id.* at PP 18, 25, 84.
119. *Id.* at P 93.
120. *Id.* at P 102.
121. *Id.* at P 122.

III. JUDICIAL DECISIONS

A. *AGF v. Columbia Gas Transmission Corp., et al.*[122]

The dismissal of three cases in September and October 2009 draws to a close a set of eight cases alleging anticompetitive behavior in natural gas transmission by several Columbia Energy Group (Columbia) companies and some of their gas shipper customers. The original cases were filed in the Kanawha County Court in West Virginia on July 14, 2004, but the story begins with an earlier FERC Order.

1. October 2000 FERC Order and Agreement

On October 25, 2000, FERC Order 1N01-1-000, 93 F.E.R.C. 61,057 (2000 FERC Order) approved a stipulation and consent agreement (2000 Agreement)[123] between the FERC and three natural gas companies who were all Columbia subsidiaries: Columbia Gas Transmission Corporation (TCO), a gas pipeline company in the eastern United States; Columbia Gulf Transmission Company (Gulf), a gas pipeline company that controlled a pipeline connecting Gulf Coast gas supply with TCO's network; and Columbia Energy Services, Inc. (CES), a gas shipper.

Natural gas transportation is regulated to encourage competition among gas suppliers and ultimately to ensure fair prices for consumers. FERC Order 636, issued in 1992, requires interstate pipeline companies to separate their gas sales services from their gas transportation services to ensure that the gas of other suppliers receives the same quality of transportation services.[124] In the case of Columbia, FERC Order 636 requires that Gulf and TCO not engage in gas sales, leaving that to their sister company CES and other gas shippers. Under the Natural Gas Act (NGA), interstate pipeline companies such as TCO and Gulf must file tariffs with the FERC for each gas storage and transportation service, specifying the rate and the terms and conditions pursuant to which the pipeline companies are required to operate.

According to the 2000 Agreement, TCO and Gulf both engaged in gas imbalance transactions, providing long-term storage services to some of their respective customers. These customers paid TCO and Gulf for these gas imbalance services.[125] TCO and Gulf did not post the availability of their gas imbalance services or communicate and make the services known to all customers. Further, TCO and Gulf did not provide the gas imbalance service to every shipper that sought to participate. The gas imbalance transactions allowed the select customers to generate revenues based on the fluctuating seasonal price of natural gas.

122. AGF v. Columbia Gas Transmission Corp., 2009 WL 2213477 (S.D. W.Va.).

123. The 2000 Agreement was the outcome of a nonpublic, preliminary FERC investigation concerning possible violations of the Natural Gas Act (NGA), 15 U.S.C. 717 (2006), the Natural Gas Policy Act of 1978 (NGPA), 15 U.S.C. 3301 (2006), and provisions of FERC's regulations.

124. An earlier order, FERC Order 436, provided an open access interstate pipeline tariff structure in which independent marketers were assured fair and equal access to interstate gas transportation and storage facilities.

125. TCO received approximately 90% of the anticipated transaction revenues for transactions of six months or longer. For transactions of lesser duration, TCO received 50%-60% of the anticipated revenues. Gulf invoiced shippers for specific dollar amounts and not for a percentage of the anticipated revenues.

The gas imbalance transactions with both TCO and Gulf were of two types: positive imbalance and negative imbalance transactions. In a positive imbalance transaction, a shipper delivers gas into the pipeline system (usually during summer or fall months), and the gas is held on the pipeline as a positive imbalance. Later, during a period of higher demand (usually in winter months), the shipper requests gas delivery, thus eliminating its positive gas imbalance. In a negative imbalance transaction, a shipper delivers gas it does not own. This volume is recorded as a negative imbalance until the shipper delivers gas back onto the pipeline's system.

According to the 2000 Agreement, beginning in February 1996 and concluding in May 1999, TCO engaged in gas imbalance transactions with eight of its customers, including its sister company CES. From January 1997 to June 1998, Gulf engaged in gas imbalance transactions with eight of its customers, not including CES. The 2000 Agreement provided that TCO and Gulf pay $27.5 million to their customers.[126] Customers that participated in the gas imbalance transactions did not receive any of the disgorgement amount. TCO, Gulf, and CES neither admitted nor denied that their actions violated the NGA, the Natural Gas Policy Act, or any other statute or FERC's regulations.

2. Second Amended Complaint Claims

On August 13, 2004, the eight original cases were removed to the U.S. District Court for the Southern District of West Virginia (the Court) as 2:04-cv-0867 and 2:04-cv-0874 (cases 0867-0874). On October 22, 2004, plaintiffs filed the Second Amended Complaint (SAC), which remained the most current complaint to the end of the litigation. In the SAC, plaintiffs largely repeated the gas imbalance transactions story in the 2000 Agreement. The alleged anti-competitive behavior began in 1996, the year the gas imbalance transactions discussed in the 2000 Agreement began, but continued indefinitely through TCO's continued purported illegal use of a parking and lending (PAL) license, which TCO acquired in 1998 and which allowed TCO to offer long-term gas imbalance services.

Transportation and storage services for gas have a hierarchy consisting of "firm," "interruptible," and storage in transit (SIT), or PAL. Firm transportation service means that the pipeline guarantees delivery at a certain time and place; the service will not be stopped or interrupted. Interruptible service means that the transportation and delivery can be stopped or delayed for a variety of reasons; there is no guarantee that the delivery will take place at a certain time or place. SIT and PAL are the lowest priority and allow a shipper to run a gas imbalance on a pipeline. SIT allows imbalances during a month. The shipper must take the gas off the pipeline before the month expires; if it does not, SIT penalties are assessed for continued storage, or "parking." PAL allows shippers to park or borrow gas for a period beyond the short-term parking allowed under SIT. Whether the service is firm, interruptible, PAL, or SIT affects the price of the service.

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126. TCO agreed to refund $1.8 million in Storage In Transit penalties, inclusive of interest, and disgorge $24.7 million to its firm and interruptible gas transportation customers. Gulf agreed to disgorge $1 million to its firm and interruptible gas transportation customers. The disgorgement amounts were based on the gas imbalance volumes on each of the TCO and Gulf systems.

Plaintiffs divided the defendants into two groups: pipeline defendants and shipper defendants. Plaintiffs added Cove Point LNG, L.P. (Cove Point),[127] a gas storage company with a storage facility connected to TCO's pipelines, as an additional pipeline defendant to TCO and Gulf. Cove Point was owned by a Columbia affiliate of TCO and Gulf until 2000, and the three companies had communicated daily pursuant to operational balance agreements.[128] In addition to the pipeline defendants, the SAC listed eight shipper defendants, including CES.[129]

Plaintiffs alleged that, in order to circumvent FERC Order 636, the pipeline and shipper defendants entered into a conspiracy whereby pipeline defendants offered preferential gas imbalance services to shipper defendants in exchange for illegal "kickback" payments. Plaintiffs were allegedly harmed through a lack of access to the gas imbalance service, through higher fees paid for storage compared to shipper defendants, and through constraints on transport of gas caused by delivery of the gas relating to the imbalance service. Plaintiffs alleged that when shipper defendants contracted for transport to deliver gas from their imbalance transactions, delivery of plaintiff shipper gas was sometimes delayed. Further, plaintiffs alleged that the pipeline defendants sometimes did not follow the hierarchy rules and gave delivery priority to shipper defendant interruptible service over plaintiff shipper firm service.

In total, plaintiffs made thirteen claims against the pipeline and shipper defendants, which are listed in Table 1 below.

	Claim	**Pipeline Defendants**	**Shipper Defendants**	**Post-*Twombly* Outcome**
1	Breach of contract	TCO		Left in.
2	Breach of good faith and fair dealing	TCO		Left in.
3	Unjust enrichment	ALL	ALL	Left in.
4	Vertical conspiracy	ALL	ALL	Must be treated as individual conspiracies between shipper and TCO. Left in.
5	Horizontal conspiracy under state law	ALL		Claim dismissed.
6	Horizontal conspiracy under state law		ALL	Claim dismissed.
7	Conspiracy to	ALL		Claim dismissed.

127. The particular named Cove Point defendants evolved over time.

128. In 2000 Williams purchased Cove Point from Columbia. In 2002 Dominion purchased Cove Point from Williams.

129. The 2000 FERC Order and 2000 Agreement did not list shipper customers by name. The SAC says the names were learned through discovery.

	monopolize under state law			
8	Conspiracy to monopolize under state law		ALL	Claim dismissed.
9	Vertical conspiracy under Sherman Act	ALL	ALL	Must be treated as individual conspiracies between shipper and TCO. Left in.
10	Horizontal conspiracy under Sherman Act	ALL		Claim dismissed.
11	Horizontal conspiracy under Sherman Act		ALL	Claim dismissed.
12	Conspiracy to monopolize under Sherman Act	ALL		Claim dismissed.
13	Conspiracy to monopolize under Sherman Act		ALL	Claim dismissed.

3. Twombly

In May 2007, the U.S. Supreme Court published its decision in *Bell Atlantic Corp. v. Twombly* (*Twombly*).[130] In *Twombly*, the Supreme Court ruled that an antitrust complaint based on parallel conduct allegations should be dismissed because the plaintiffs had failed to present enough facts for the case to survive in federal court.

Following this Supreme Court decision, first the shipper defendants and then the pipeline defendants asked the Court to reconsider its opinion on the defendants' motion to dismiss in light of *Twombly*. On October 18, 2007, the Court dismissed the horizontal conspiracy and conspiracy to monopolize claims involving shipper defendants. The Court found that plaintiffs did not present evidence that shipper defendants communicated with each other. The same October 2007 order limited the vertical conspiracy claims to separate conspiracy claims between individual shipper and pipeline defendants.

In early 2008, the pipeline defendants similarly requested the Court reconsider the earlier motion to dismiss in light of *Twombly*.[131] With respect to the pipeline horizontal conspiracy and conspiracy to monopolize claims, the Court found that plaintiffs did not present evidence that Cove Point knew of or engaged in any conspiracy. When Gulf then requested the Court reconsider the

130. 550 U.S. 544 (2007).

131. Cove Point and Gulf motions to reconsider were filed separately, and the Court addressed them separately. The Court responded to Cove Point's motion on Jan. 4, 2008, and Gulf's motion on March 4, 2008.

earlier motion to dismiss, plaintiffs did not oppose the motion to dismiss the horizontal conspiracy and conspiracy to monopolize claims. On April 15, 2008, the parties stipulated dismissal of Cove Point and all related entities.

Following the post-*Twombly* orders, vertical conspiracy and unjust enrichment claims remained for all remaining defendants and two additional non-antitrust claims remained against TCO.

4. Class Certification Denied

On June 9, 2005, the Court consolidated the eight cases, and on December 1, 2005, plaintiffs submitted their first motion for class certification. The Court decided that discovery was necessary before deciding on the class certification motion. After almost two years of discovery, plaintiffs submitted their renewed motion for class certification on November 19, 2007.

On August 19, 2008, the Court denied plaintiffs' motion of class certification. The Court found that plaintiffs had successfully shown numerosity, commonality, and typicality, but had failed to show adequacy of representation, predominance of common questions over questions affecting only individual members, and superiority of class resolution over other methods.

On the question of adequacy of representation, the Court found that conflicts of interest might inhibit the named plaintiffs from adequately representing the interests of the proposed class. The defendants noted that all but one of plaintiffs had been out of the gas shipping business for several years, and the remaining plaintiff shipper had engaged in transactions with TCO that had features that their claims sought to condemn. The Court also noted that some shipper defendants were removed from the suit without explanation and some shippers were not party to the suit at all. According to plaintiffs, forty-three shippers participated in the scheme, yet only eight were listed as defendants. The defendants argued that the named plaintiffs could not adequately represent the interests of those class members whose injuries were caused by the conduct of nonparties. Finally, to prove lost profits, each plaintiff would seek to prove how much business they could have obtained and how much they could have prospered had the defendants' actions not stifled them. In order to maximize its damages award, each plaintiff had an incentive to minimize the other plaintiffs' losses.

On predominance of common questions, the Court found individual questions predominated in the vertical conspiracy liability and lost profit damages claims, as well as in the unjust enrichment claims and on statute of limitation issues. With respect to vertical conspiracy liability, based on plaintiffs' description, each individual shipper defendant entered into a separate contract with TCO to receive preferential rates. Plaintiffs would be were required to show which individual defendants and which of their transactions injured which individual plaintiff in each instance – by time and location – to demonstrate that the conduct violated antitrust laws. That is, the determination of liability of each defendant shipper could not be based on the conduct of other shippers.

With respect to lost profits, the Court cited precedent noting that a "claim for lost profits damages was not a natural candidate for class-wide resolution; the calculation of lost profits is too 'dependent upon consideration of the unique circumstances pertinent to each class member.'"[132] With respect to unjust enrichment, "the Court would need to consider the conduct of each individual defendant and each individual plaintiff to determine which defendant was unjustly enriched by which plaintiff."[133]

Finally, the Court noted that the statute of limitations may have run out for some class members, requiring individual inquiry. The statute of limitations for antitrust claims is four years. The latest date on which the plaintiffs could have been put on notice of the alleged conspiracy is the date of the October 2000 FERC Order. The July 2004 complaint filing occurred almost four years after the 2000 FERC Order, and the federal antitrust claims were not added to the complaint until October 22, 2004. Individual inquiry would be needed to determine if individual plaintiffs were put on notice prior to the October 2000 FERC Order.

On the question of the superiority of a class action, the Court found that the management of such a class action would likely become unwieldy given the individual questions of fact that will arise regarding the nature and terms of each contract, the location and nature of each transaction, and the potential adverse impact to each other plaintiff – as well as whether such impact was illegal or not. Further, each plaintiff would require a subsequent individual damages trial where the proof required would replicate the evidence relied upon in the class-wide trial in order to support the individual damage claims.

5. 2009 Resolution

On December 31, 2008, the Court ordered a voluntary dismissal with prejudice of the lead case, Case 0867 (Plaintiff Stand Energy Corporation), and subsequently sent the remaining cases back to their respective dockets. At this point, Case 0868 (Plaintiff Triad Energy Resources Corporation) was dismissed without prejudice, and Case 0874 (Plaintiff AtlantiGas Corporation) was marked closed as of July 5, 2005. After the Court ordered a voluntary dismissal with prejudice of Case 0873 (Plaintiff Nicole Gas Marketing, Inc.) on January 22, 2009, four cases remained with Case 0869 as the lead case.

The Court proceeded to remove TCO's sister companies Gulf and CES as defendants. The Court terminated Gulf as a defendant on January 22, 2009, leaving TCO as the sole pipeline defendant. On April 23, 2009, the Court ruled that CES and TCO were sister corporations and thus could not have conspired. The Court ruled that the FERC regulations requiring that TCO treat CES as a completely separate and independent entity were insufficient basis to support an antitrust claim against CES.

On April 3, 2009, the Court granted the defendants' motion for summary judgment of the plaintiffs' unjust enrichment claims without a detailed explanation. Case 0869 (Plaintiff Energy Marketing Services, Inc.) settled and was dismissed on May 7, 2009, leaving case 0870 as the lead case.

In July 2009, the Court granted summary judgment on all remaining antitrust claims to the defendants because the statute of limitations had expired

132. Broussard v. Meineke Discount Muffler Shops, Inc., 155 F.3d 331 (4th Cir. 1998) (*quoting* Boley v. Brown, 10 F.3d 318, 223 (4th Cir. 1993)).

133. *Id.*

in each of the three remaining cases. On July 2, 2009, the Court granted summary judgment to the defendants in Case 0871 on all claims and Case 0872 on antitrust claims. These plaintiffs had not shipped gas on TCO pipeline in the four years prior to filing suit, and state and federal antitrust law have a four-year statute of limitations. On July 14, 2009, the Court granted summary judgment on antitrust claims to the defendants in Case 0870, citing for its reasoning the July 2 ruling. Case 0870 (Plaintiff AGF, Inc.) settled and was dismissed on September 18, 2009. Case 0872 (Plaintiff East Lancaster Avenue Business Trust) settled and was dismissed on October 8, 2009. Case 0871 (Plaintiff Advantage Energy Marketing, Inc.) was appealed and then dismissed October 22, 2009.

B. Pacific Bell Telephone Co. v. Linkline Communications, Inc.

In *Pacific Bell Telephone Co. v. Linkline Communications, Inc.*,[134] the Supreme Court granted certiorari to resolve a conflict among the Courts of Appeals concerning the circumstances in which a plaintiff may pursue a "price squeeze" claim under Section 2 of the Sherman Act. Relying in part on its earlier decision in *Verizon Communications Inc. v. Law Offices of Curtis V. Trinko, L.L.P.*,[135] the Court held that such a claim cannot be maintained where the defendant has no antitrust duty to deal with the plaintiff.[136]

A "price squeeze" is said to occur when a defendant, who operates in both the wholesale and retail markets (and therefore competes with its wholesale customers in the retail market), raises prices in the wholesale market while simultaneously cutting prices in the retail market. This is seen as "squeezing" the profit margins of its retail competitors. In essence, these claims involve allegations that a defendant has charged too much for wholesale service, while charging too little for retail service.[137] As the Court of Appeals noted in the decision under review by the Supreme Court, "[f]or over six decades, federal courts have recognized price squeeze allegations as stating valid claims under the Sherman Act." [138]

The *Linkline* case involved the market for digital subscriber line (DSL) service, which provides high-speed access to the Internet. The defendants (various corporate entities collectively referred to as AT&T) were engaged in both the wholesale and retail DSL markets, providing "DSL transport service" to various internet service providers at the wholesale level, while also furnishing internet access to individual retail customers. The plaintiffs were Internet service providers who obtained DSL transport service by leasing facilities from AT&T, while simultaneously competing with AT&T to provide retail Internet access. The plaintiffs claimed, among other things, that AT&T had squeezed their profit margins by setting a high wholesale price for DSL transport service, while setting a low price for its own DSL internet service. This, according to the plaintiffs, excluded and unreasonably impeded competition, allowing the

134. 129 S. Ct. 1109 (2009).

135. 540 U.S. 398 (2004).

136. *Pacific Bell Telephone Co.*, 129 S. Ct. at 1114-15.

137. *See generally* Town of Concord v. Boston Edison Co., 915 F.2d 17 (1st Cir. 1990).

138. Linkline Communications, Inc. v. SBC California, Inc., 503 F.3d 876, 880 (9th Cir. 2007).

defendant to maintain monopoly control of DSL access to the Internet.[139] Both the District Court and the Court of Appeals found that plaintiffs' allegations were sufficient to state a claim under section 2 of the Sherman Act.

At the outset, the Supreme Court had to determine whether the case was moot. On appeal, the plaintiffs had changed their position and essentially adopted the views of the dissenting judge on the Court of Appeals. They asked that the case be remanded so that they could amend their complaint. In addition, certain amici argued that the case should be dismissed for lack of an adversarial presentation. The Court, however, rejected those contentions and found that the case was not moot, in part because the main parties were seeking different relief, in part because two amici had submitted briefs defending the Court of Appeals decision (and had been permitted to participate in oral argument), and in part because the plaintiffs had defended the Court of Appeals decision at the certiorari stage and the parties had invested substantial efforts and resources in briefing and arguing the merits of the case. The Court also saw a need to resolve the conflict among the circuits.[140]

Turning to the merits, the Court began by examining the plaintiffs' claims involving the wholesale market, in which AT&T provided DSL transport service. The Court reiterated the general rule, first enunciated in *United States v. Colgate & Co.*,[141] that "businesses are free to choose the parties with whom they will deal, as well as the prices, terms, and conditions of that dealing."[142] While acknowledging that there were "limited circumstances" in which a firm's unilateral refusal to deal could give rise to antitrust liability, the Court noted that the District Court had found that AT&T had no antitrust duty to deal with its competitors, and that ruling had not been challenged on appeal.[143]

As a result, the Court concluded that a "straightforward application" of its earlier decision in *Verizon Communications, Inc. v. Law Offices of Curtis V. Trinko, L.L.P.*[144] foreclosed any challenge to AT&T's wholesale prices.[145] In *Trinko*, the plaintiff, who was a customer of one of Verizon's competitors, alleged that Verizon had denied its competitors access to its telecommunications network facilities, making it difficult for the competitors to fill their retail customers' orders. The Court found that Verizon's conduct was not actionable under section 2 of the Sherman Act. Since Verizon had no antitrust duty to deal with its competitors, its alleged "insufficient assistance" to those competitors did not violate the provisions of the Sherman Act.[146] As the Court interpreted its earlier holding: "*Trinko* thus makes it clear that if a firm has no antitrust duty to deal with its competitors at wholesale, it certainly has no duty to deal under terms and conditions that the rivals find commercially advantageous."[147]

139. *Pacific Bell Telephone Co*., 129 S. Ct. at 1115.

140. *Id.* at 1117.

141. 250 U.S. 300 (1919).

142. *Pacific Bell Telephone Co.*, 129 S. Ct. at 1118.

143. *Id.* (AT&T did have an obligation to provide DSL Transport Service as a condition for a previous merger, but that obligation was deemed irrelevant to the antitrust claims).

144. 540 U.S. at 398.

145. *Pacific Bell Telephone Co.*, 129 S. Ct. at 1119.

146. *Id.*

147. *Id.*

Finding no reason to distinguish, for antitrust purposes, between price and nonprice components of a transaction, the Court concluded that there was no meaningful difference between the claims of "insufficient assistance" in *Trinko* and the price-squeeze claims presented in Linkline. Since AT&T had no antitrust duty to offer wholesale service at all, it was not required to offer it at "prices the plaintiffs would have preferred,"[148] and plaintiff's claims concerning AT&T's wholesale prices were therefore not cognizable under the Sherman Act.

The Court then turned to the other component of the price squeeze claim: the allegation that AT&T's retail prices were too low. The Court first noted that cutting prices to increase business was often the very essence of competition, and that to avoid chilling aggressive price cutting, its prior decisions had carefully limited the circumstances in which plaintiffs could state a Sherman Act claim by arguing that prices were too low. To prevail on such a "predatory pricing" claim, a plaintiff must satisfy the two-pronged test set forth in *Brooke Group Ltd. v. Brown & Williamson Tobacco Corp*.[149] That test requires a demonstration that (1) the prices complained of are below an appropriate measure of a rival's costs, and (2) there is a "dangerous probability" that the defendant will be able to recoup its "investment" in below-cost prices.[150] Since the allegations in the plaintiffs' original complaint failed to satisfy either prong of the *Brooke Group* test, they failed to state a cognizable claim under the Sherman Act.

The Court then summarized its overall conclusions:

> Plaintiffs' price-squeeze claim, looking to the relation between retail and wholesale prices, is thus nothing more than an amalgamation of a meritless claim at the retail level and a meritless claim at the wholesale level. If there is no duty to deal at the wholesale level and no predatory pricing at the retail level, then a firm is certainly not required to price *both* of these services in a manner that preserves its rivals' profit margins.[151]

The Court added that institutional concerns also counseled against recognizing such price-squeeze claims. Those concerns included the need for courts to simultaneously police both wholesale and retail prices in order to enforce such claims (arguably placing the courts in a role better suited for a regulatory agency), as well as the difficulty of determining a "fair" or "adequate" margin between the wholesale and retail prices, and the resulting lack of a "safe harbor" for a firm's pricing practices.[152] The case was remanded to the District Court, which would decide whether to allow the plaintiffs to move forward with an amended complaint alleging predatory pricing.

Four justices concurred in the judgment, stating that they would have accepted plaintiffs' concession that the Court of Appeals erred in its "price-squeeze" holding, vacated that decision, and remanded the case to the District

148. *Id.*

149. 509 U.S. 209 (1993).

150. *Pacific Bell Telephone Co.*, 129 S. Ct. at 1120.

151. *Id.*

152. *Id.* at 1120-21 (Court also rejected a suggestion by amici that it establish a "transfer price" test, under which a price squeeze would be presumed if an upstream monopolist could not have made a profit by selling at its retail rate if it purchased the necessary inputs at its own wholesale rate. The Court found that such a test lacked "any grounding in [its] antitrust jurisprudence". *Id*. at 1122).

Court to determine whether plaintiffs should be permitted to proceed with their predatory pricing claim.[153]

C. Maine Public Utilities Commission v. FERC

In *Maine Public Utilities Commission v. FERC*,[154] the D.C. Circuit reversed and remanded the FERC's order approving a settlement provision that applied the *Mobile-Sierra* doctrine's more restrictive "public interest" standard to both settling-party and non-settling-party rate challenges.[155] The Maine Public Utilities Commission and the Attorneys General of Connecticut and Massachusetts, as petitioners on appeal, had challenged the Commission's approval of a comprehensive settlement agreement that redesigned New England's capacity market, arguing generally that the Commission's approval of the settlement was arbitrary and capricious, contrary to law, and beyond the scope of the Commission's jurisdiction.

The petitioners presented the District of Columbia Circuit Court with four issues for review, but the D.C. Circuit's *per curiam* ruling granted review of only one of them—a matter of first impression concerning whether the Commission could enforce a regionally-global settlement agreement that would apply the more stringent "public interest" standard of the *Mobile-Sierra* doctrine to rate challenges brought by parties who did not join the settlement.[156]

In granting review on this issue, the D.C. Circuit determined that the Commission could not apply the settlement agreement's *Mobile-Sierra* provision to rate challenges mounted by non-contracting third-parties, but must instead apply the less stringent "just and reasonable" standard of review set forth in section 206 of the FPA.[157]

In its order on remand, the Commission declared that the settlement agreement remained approved, but ordered the 115 settling parties to submit, consistent with the court's decision, a compliance filing revising the standard of review applicable to non-settling third parties.[158]

By way of background, power generators in the New England capacity market had long been struggling with maintaining reliability standards in the face of insufficient revenue. As summarized by the D.C. Circuit, "the supply of capacity was barely sufficient to meet the region's demand."[159] After years of

153. *Id.* at 1123-25.

154. 520 F.3d 464 (D.C. Cir. 2008).

155. Summarized, the *Mobile Sierra* doctrine stands for the proposition that, absent a showing of harm to the public interest, the Commission cannot undo contract rules. Morgan Stanley Capital Group Inc. v. Pub. Util. Dist. No. 1, 128 S. Ct. 2733, 2737 (2008) (it should be noted, this was decided after the D.C. Circuit's opinion in Maine Pub. Utils. Comm'n v. FERC).

156. The petitioners also claimed that the FERC's acceptance of the settlement agreement was arbitrary and capricious because (a) the transition payment scheme lacked sufficient generator cost data, and (b) the arrangement failed to include non-locational pricing during the transition period—but the D.C. Circuit denied these claims, as well as rejected the petitioners' contention that FERC had exceeded its jurisdiction because the settlement agreement forced utilities to purchase a specific amount of capacity.

157. 16 U.S.C. § 824(a) (2006).

158. *Devon Power, L.L.C.*, 126 F.E.R.C. ¶ 61,027 (2009).

159. Unlike a wholesale electricity market that envisions the direct purchase of specific capacity, a "capacity market" presupposes that the electricity retailer will pay for the option of buying a specific quantity of the power generator's installed capacity "irrespective of whether it ultimately buys the electricity." *Maine Pub. Utils. Comm'n*, 520 F.3d at 467, *citing* Keyspan-Ravenswood v. FERC, 474 F.3d 804, 806 (D.C. Cir.

proceedings, however, on June 16, 2006,[160] a super-majority of the parties, 115, eventually arrived at a settlement agreement, which the Commission approved. Eight parties, including the petitioners, refused to join the settlement.

Side-stepping what's known as the "locational market" approach because it relied on a highly controversial demand curve, the parties to the settlement agreement developed a new mechanism with two noteworthy features, including (1) the so-called "forward capacity market," which would conduct annual capacity auctions three years in advance of when the capacity is needed,[161] and (2) a transition period from December 1, 2006 through June 1, 2010, that would require fixed payments to power generators to cover the three-year gap between the first auction and the delivery date for the procured capacity.[162]

The settlement agreement, however, imposed a provision whereby any challenges to the transition payments and the "final forward market" auction clearing prices would be subject to the more stringent "public interest" standard and not the less rigorous "just and reasonable" standard—regardless of whether a settling or non-settling party brought the challenge.[163]

Section 206 of the FPA generally requires the Commission to adjudicate rate challenges under the "just and reasonable" standard. Under the *Mobile-Sierra* doctrine, however, the Commission must, as a matter of law and public policy, duly enforce the parties' voluntary bargain—unless the public interest requires otherwise, meaning the Commission may abrogate or modify private contracts only where the freely negotiated rates "might impair the financial ability of the public utility to continue its service, cast upon other customers an excessive burden, or be unduly discriminatory."[164]

In *Sierra*, Pacific Gas & Electric sold surplus hydroelectric power to Sierra at a substantially reduced rate, but, with the Commission's approval, terminated the contract and increased Sierra's rates when the surplus dissipated. The Supreme Court, however, held for Sierra, requiring the Commission to apply the deferential and largely outcome-determinative "public interest" standard of review. Thus, unless the contractually-negotiated rates being challenged somehow contravene the public interest, the Commission may not modify them.[165] Put another way, absent a public interest basis, it is much more difficult

2007) (option mechanism is intended to enable electricity retailers to respond to fluctuations in demand and maintain grid reliability).

160. *Devon Power, L.L.C*., 115 F.E.R.C. ¶ 61,340 (2006); *Devon Power, L.L.C.*, 117 F.E.R.C. ¶ 61,133 (2006); *Maine Pub. Utils. Comm'n*, 520 F.3d at 469; *Devon Power, L.L.C.*, 126 F.E.R.C. ¶ 61,027 (2009).

161. Viewed as a mechanism for attracting new market entrants, the locational market approach would create sub-regions within a larger market, allowing for differential pricing at significantly higher rate levels in those sub-regions constrained by more severe capacity shortages. The three year lead time under the settlement planning period, on the other hand, would provide new entrants a substantial planning period and "allow potential new capacity to compete in the auctions." *Maine Pub. Utils. Comm'n*, 520 F.3d at 469; *Devon Power, L.L.C.*, 115 F.E.R.C. ¶ 61,340, 62306 (2006).

162. *Maine Pub. Utils. Comm'n*, 520 F.3d at 469; *Devon Power, L.L.C.*, 126 F.E.R.C. ¶ 61,027 (2009).

163. *Id.*

164. Fed. Power Comm'n v. Sierra Pacific Power Co., 350 U.S. 348, 355 (1956); *Maine Pub. Utils. Comm'n*, 520 F.3d at 477; Atlantic City Elec. Co. v. FERC, 295 F.3d 1, 14 (D.C. Cir. 2002) ("The purpose of the *Mobile Sierra* doctrine is 'to preserve the benefits of the parties' bargain as reflected in the contract, assuming that there was no reason to question what transpired at the contract formation stage.'")

165. *See also* United Gas Pipeline Co. v. Mobile Gas Serv. Corp., 350 U.S. 332, 344 (1956) (in similarly upholding the integrity and stability of negotiated agreements, precluded natural gas companies "from

for the two parties in a rate dispute to overcome the presumption that their previously negotiated rate is anything but just and reasonable.

The Commission defended its position before the D.C. Circuit with three central arguments. First, it claimed that the "public interest" standard would only apply on a going-forward basis to a narrow category of rates, including, specifically, the transition payments and the final auction clearing prices from the forward market. The D.C. Circuit, however, rejected this argument, deeming it "equivalent to arguing that FERC will use an illegal standard sparingly." For the court, the Commission's applying the "public interest" standard on even a "limited" basis would still deprive the non-settling parties of their statutory right to adjudicate rate challenges under the "just and reasonable" standard.[166]

Secondly, the Commission argued that it had approved contracts in other recent cases that applied the "public interest" standard to non-contracting parties, as well as called attention to the lack of a Commission or court precedent where a non-signing party had unilaterally sought to change a *Mobile-Sierra* agreement under the "just and reasonable" standard of review."[167] As to the former contention, the D.C. Circuit noted that the Commission's applying such policy consistently "does not necessarily support the policy's legality."[168] As to the latter, apart from citing to the plain language of section 206 of the FPA that requires the Commission, upon complaint, to determine whether the challenged rate is unjust and unreasonable, the D.C. Circuit recycled the Commission's logic with more than a hint of irony, observing it "could just as easily be said that there is no 'court precedent' that supports altering third parties' statutory rights based on a contract that they refused to sign."[169]

Finally, the Commission claimed that applying the *Mobile-Sierra* "public interest" standard in this instance was generally "necessary to promote price certainty and contract stability."[170] The D.C. Circuit, however, was unable to accept this broader view, declaring that the purpose of the *Mobile-Sierra* was "to ensure contract stability *as between the contracting parties*—i.e., to make it more difficult for either party to shirk its contractual obligations."[171] For the court, therefore, it boiled down to one inescapable and literal fact: the petitioners refused to sign the settlement agreement terms, so it made "no sense" to vindicate the contract values of stability and certainty by applying the more deferential standard of review to the non-settling third parties.

Following the Commission's January 15, 2009 order on remand, one of the settling parties, NRG Power Marketing, L.L.C. and its affiliates, filed with the United States Supreme Court a petition for certiorari, which the Supreme Court granted on April 27, 2009. Argued on November 3, 2009, under the caption *NRG Power Marketing, L.L.C. v. Maine Public Utilities Commission*, No. 08-674, the petitioners contended, among other things, that the D.C. Circuit's

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unilaterally changing their contracts simply because it is in their private interests to do so"—excepting "when their interests coincide with the public interest).

166. *Maine Pub. Utils. Comm'n*, 520 F.3d at 478.

167. *Id.*

168. *Id.*

169. *Id.*

170. *Id.* at 479.

171. *Id.* (emphasis in the original).

decision conflicts with the Supreme Court's subsequent ruling in *Morgan Stanley*,[172] and would destroy the contract stability *Mobile-Sierra* was intended to provide, allowing indirect parties the benefit of relying on a weaker standard of review than is available to the very parties who negotiated and agreed to the contract rate.[173] The respondents, on the other hand, essentially argued (a) that the settlement agreement did not fall within the ambit of the *Mobile-Sierra* doctrine; and (b) given the nature of the underlying settlement process, the approved agreement invited fair comparison to tariff rates, which generally apply to all market participants throughout New England.[174]

The Commission, for its part, simply held fast to the view that it permissibly exercised its discretion in approving the settlement agreement, and acted reasonably in applying the public interest standard to any subsequent rate challenges that might occur under the settlement agreement. For the Commission, that discretion extends to the view that the forward market auction process itself will result in presumptively "just and reasonable rates," which, in the interest of rate stability, then merits shielding the auction process by means of the public interest standard.[175] At least one remark from the bench during oral argument, from Chief Justice Roberts, more than suggested that the Supreme Court's eventual ruling[176] would hinge on this pivotal point of discretion – the Maine PUC, he said, is:

> in a very tough position because of the way this has progressed. I think you can make a strong argument that you shouldn't be bound by these contract rates if FERC doesn't have a lot of discretion to let you go. If FERC has a lot of discretion to let you go, your argument that you shouldn't be bound is a lot weaker.[177]

On January 13, 2010, joined by Chief Justice Roberts and Justices Scalia, Kennedy, Thomas, Breyer, Alito, and Sotomayor, with Justice Stevens dissenting, Justice Ginsburg delivered the opinion of the Court, holding that the *Mobile-Sierra* presumption applies to all challenges to contract rates, even when a non-contracting party initiates the challenge.[178] "[I]f FERC itself must presume just and reasonable a contract rate resulting from fair, arms-length negotiations, how," the Court asked, "can it be maintained that non-contracting parties nevertheless may escape that presumption?"[179] For the Court, a "presumption applicable to contracting parties only, and inoperative as to everyone else . . . could scarcely provide the stability *Mobile-Sierra* aimed to secure."[180] Thus, when it comes to rate challenges involving contract rates, the

172. *Morgan Stanley*, 128 S. Ct. at 2745 (the Supreme Court held that "[t]here is only one statutory standard for assessing wholesale electricity rates, whether set by contract or tariff – the just and reasonable standard").

173. *See generally* Brief for Petitioners, NRG Power Marketing v. Maine Pub. Util. Comm'n, No. 08-674 (S. Ct. 2010), *available at* http://www.abanet.org/publiced/preview/briefs/pdfs/07-08/08-674_Petitioner.pdf.

174. *Id.*

175. *Id*.

176. As of this writing, the Supreme Court has yet to issue its opinion.

177. NRG Power Marketing, L.L.C. v. Maine Public Utilities Commission, http://www.scotuswiki.com/index.php?title=NRG_Power_Marketing%2C_LLC_v._Maine_Public_Utilities_Commission (last visited Mar. 6, 2010).

178. NRG Power Marketing, L.L.C. v. Maine Pub. Util. Comm'n, No. 08-674 (S. Ct. Jan. 13, 2010).

179. NRG Power Marketing, L.L.C. v. Maine Pub. Util. Comm'n, No. 08-674, slip op. at 9 (S. Ct. Jan. 13, 2010).

180. *Id.* at 10.

Court determined that the *Mobile-Sierra* presumption makes no distinction based on the complainant's identity.

The Court, however, remanded the case to the D.C. Circuit to determine whether the settlement rates at issue qualify as "contract rates," and, if not, whether the FERC had discretion to treat them as analogous to contract rates.[181]

D. Sipco, L.L.C. v. Florida Power & Light Company, et al.

In *Sipco, L.L.C. v. Florida Power & Light Company*, filed in the U.S. District Court for the Southern District of Florida (Miami Division),[182] on July 27, 2009, the plaintiff alleges that Defendants Florida Power & Light Company (FP&L) and FPL Group, Inc.[183] infringed on three patents issued to Sipco related to "smart grid" technology. The suit alleges that FP&L's "Energy Smart Miami" initiative infringes on wireless network product and services technology patents found in Sipco's Smart Grid system. The suit alleges that the infringing systems include wireless network technology found in the utility meters, applications and control systems, wireless communications protocols, devices, network interface cards, computer devices, enabling software, data collection and processing, and associated communications platforms, gateways, and controls. Energy Smart Miami initiative would enable computers located at FPL's central offices to monitor utility meters at Miami's homes and businesses through a "Smart Grid" network of interconnected wireless transmitters and receivers, together with relay and access point devices that interface between the wireless network of meters and the Internet. Although the city of Miami announced the Energy Smart Miami initiative on April 20, 2009, the initiative has not yet been implemented.

The *Sipco v FPL* action stems from an agreement entered into between Silver Spring Networks, Inc. (SSN) and FP&L under which SSN will provide (1) the "Network Interface Cards" that will gather data from FP&L's utility meters and transmit that data through the wireless network, (2) the "relays" that transmit the collected data further through the wireless network, (3) the "access point" devices that forward signals from the wireless network to the Internet, and vice versa, and (4) the "UtilityIQ" software that runs on the central office computer and controls the entire system. On September 4, 2009, Sipco filed an amended complaint in the Florida action naming SSN as an additional defendant. SSN filed a companion case, *SilverSpring Networks, Inc. v. Sipco, L.L.C.*,[184] in the U.S. District Court for the Northern District of Georgia to resolve the broader question of whether SSN's Smart Grid Network infringes Sipco's patents. Pursuant to a contractual agreement, SSN has agreed to indemnify and defend FP&L against Sipco's claims.[185]

The parties to the Florida action have agreed to mediate the dispute and a mediation session was held on November 21, 2009. The parties provided telephonic notice of settlement to the Court on November 23, 2009 and the parties were given until December 23, 2009 to file their Settlement papers with

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181. *Id.* at 11.
182. Sipco v. Florida Power & Light Co., No 09-22209 (S.D. Fla. July 27, 2009).
183. FPL Group, Inc. was dismissed out of the lawsuit as a Defendant on October 8, 2009.
184. SilverSpring Networks, Inc. v. Sipco, No. 1:09-CV-2215 (N.D. Ga. Sept. 4, 2009).
185. Motion by Defendants to Stay, Transfer, or Sever and Transfer, SilverSpring Networks, Inc. v. Sipco, No. 1:09-CV-2215 (N.D. Ga. Sept. 8, 2009).

the Court. Plaintiff's counsel advises that the Settlement Agreement is confidential.

IV. ANTITRUST AGENCY INITIATIVES AND DEVELOPMENTS

A. U.S. Department of Justice Section 2 Report

On May 11, 2009, the new Assistant Attorney General for Antitrust, Christine A. Varney, withdrew the DOJ's Section 2 Report, stating that it "no longer represents the policy of the Department of Justice with regard to antitrust enforcement under Section 2 of the Sherman Act."[186] The Report, titled "Competition and Monopoly: Single-Firm Conduct Under Section 2 of the Sherman Act,"[187] was issued eight months earlier by AAG Varney's predecessor, Thomas O. Barnett; it examined "whether and when specific types of single-firm conduct may or may not violate Section 2 of the Sherman Act by harming competition and consumer welfare."[188] Although the report drew on a series of joint hearings held by the DOJ and FTC from June 2006 to May 2007, the FTC declined to join the DOJ's report and three of four FTC commissioners issued a statement that criticized the report as a "blueprint for radically weakened enforcement of section 2."[189]

In announcing withdrawal of the report, AAG Varney stated that it "provides a comprehensive evaluation of the history of single-firm enforcement and careful consideration of the risks and benefits of particular enforcement strategies. The Report's ultimate conclusions, however, miss the mark. In my view, the greatest weakness of the Section 2 Report is that it raises many hurdles to Government antitrust enforcement."[190] The withdrawal, said Varney, represented "a shift in philosophy and the clearest way to let everyone know that the Antitrust Division will be aggressively pursuing cases where monopolists try to use their dominance in the marketplace to stifle competition and harm consumers."[191] Varney stated that in place of the withdrawn report, the DOJ would "return to tried and true case law and Supreme Court precedent in enforcing the antitrust laws."[192]

186. Christine A. Varney, Assistant Attorney General, Antitrust Division, Department of Justice, *Vigorous Antitrust Enforcement in this Challenging Era* (May 11, 2009), *available at* http://www.usdoj.gov/atr/public/speeches/245711.pdf; Press Release, Justice Department Withdraws Report on Antitrust Monopoly Law (May 11, 2009), *available at* http://www.usdoj.gov/atr/public/press_releases/2009/245710.pdf.

187. DEPARTMENT OF JUSTICE, COMPETITION AND MONOPOLY: SINGLE FIRM CONDUCT UNDER SECTION 2 OF THE SHERMAN ACT (2008), *available at* http://www.justice.gov/atr/public/reports/236681.pdf.

188. Press Release, Justice Department Issues Report on Antitrust Monopoly Law (Sept. 8, 2008), *available at* http://www.justice.gov/atr/public/press_releases/2008/236975.pdf.

189. Statement of Commissioners Harbour, Leibowitz and Rosch on the Issuance of the Section 2 Report by the Department of Justice 1 (Sept. 8, 2008), *available at* http://www.ftc.gov/os/2008/09/080908section2stmt.pdf.

190. Christine A. Varney, *supra* note 186.

191. Press Release, *supra* note 186.

192. *Id.*

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