

WHAT IS HAPPENING AND WHERE IN THE WORLD OF RTOS AND ISOS?

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I. INTRODUCTION

With the implosion of standardized market design,¹ the Federal Energy Regulatory Commission (FERC or the Commission) has wisely returned to a regional approach to the development of Regional Transmission Organizations (RTOs) and Independent Transmission System Operators (ISOs). Nevertheless, this noble experiment has not been without controversy, complexity, and uncertainty. Indeed, there has been considerable tension between state and federal regulators, generators and load interests, and other industry members, as to which regional approaches will be reliable, yet cost-effective for consumers. Given the pace and diversity of regional development, the authors thought it would be helpful to provide energy bar practitioners with a survey of “what is happening and where” in the world of RTOs and ISOs.

This article briefly recaps RTO and ISO development beginning with Order No. 888 and surveys the current trends in regions across the country as policy development continues to evolve at the FERC and in the judiciary. It explores issues that have emerged, such as the need to develop capacity markets and reserves markets, the proliferation of Reliability Must Run agreements, and other prominent issues. It considers the divisions of responsibility over reliability, including the promulgation of rules, implementation, enforcement, and the role of the stakeholder process. Finally, it demonstrates how different RTOs have sought different solutions to accommodate circumstances unique to each region.

This article also identifies several issues that remain unsettled concerning RTOs and ISOs. For instance, what is the best approach to ensuring resource adequacy? Several approaches to resource adequacy and reliability compensation, such as Midwest ISO’s energy-only market and PJM Interconnection’s Reliability Pricing Model proposal are discussed. In addition, currently (as of March 2006), the Commission is reviewing a proposal for a Locational Installed Capacity (LICAP) market design for New England, which is targeted to adequately compensate existing generation and stimulate investment in new generation. A similar proposal has been adopted in New York, however, some argue that the capacity market there is too young to conclude whether the mechanism stimulates new investment as intended. A number of parties in the LICAP proceeding have contested aspects of the New England proposal and have put forward alternatives for the Commission’s consideration, and a

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1. See Notice of Proposed Rulemaking, *Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design*, F.E.R.C. STATS. & REGS. ¶ 32,563, 67 Fed. Reg. 55,451 (2002) [hereinafter SMD NOPR].

settlement resolving all issues was filed on March 6, 2006.² Also in the LICAP proceeding, the Commission has underscored the importance of reducing or eliminating reliance on Reliability Must Run (RMR) contracts, which have proliferated in New England and elsewhere. However, the debate over how this will be effectively accomplished continues.

Another matter that has gained much attention recently is how best to deal with market manipulation and the exercise of market power. In response to the Western energy crisis of 2000–2001, the Energy Policy Act of 2005 (EPA 2005) amended the Natural Gas Act and the Federal Power Act to prohibit energy market manipulation and enhanced the Commission's authority to assess civil penalties for violations. However, what roles should RTOs and ISOs have concerning the prevention of market manipulation and the exercise of market power? While several ISOs have had broad authority to correct market design implementation flaws when they commenced operations, this sort of authority was viewed as a temporary measure to assist in the initial implementation of the markets. As discussed further below, the precise role of ISOs/RTOs and their market monitoring units in preventing market manipulation is now somewhat uncertain. Further, following the August 14, 2003 Northeast blackout and the 2004 cold snap in New England, RTO and ISO development has increasingly captured the attention of policymakers on the federal, regional, and state levels.

Finally, while this article explores current issues that arise within the structure of existing ISOs and RTOs, it is important to remember that not all areas of the country have established an ISO or RTO. Thus, further areas of consideration also include what form of organization would best suit those regions? Moreover, how could cost-effectiveness of such organizations, as well as ISOs and RTOs, be ensured? This article provides a survey of the current state of development of RTOs and ISOs. However, all of these issues will merit further consideration as the industry continues to change rapidly.

II. ORDER NO. 888

In 1996, the Commission issued Order Nos. 888³ and 889,⁴ which required, as a remedy for undue discrimination, that all public utilities provide open access transmission service consistent with the terms and conditions of a *pro forma* OATT and stranded cost recovery rules that would provide a transition to competitive markets.

2. Explanatory Statement in Support of Settlement Agreement of the Settling Parties, FERC Docket Nos. ER03-563-000, ER03-030-000, ER03-055-000 (2006) [hereinafter Explanatory Statement]; Request for Expedited Consideration and Settlement Agreement Resolving All Issues, Devon Power LLC, FERC Docket Nos. ER03-563-000, ER03-030-000, ER03-055-000 (2006).

3. Order No. 888, *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, [Regs. Preambles 1991–1996] F.E.R.C. STATS. & REGS. ¶ 31,036 (1996), 61 Fed. Reg. 21,540 (1996) (to be codified at 18 C.F.R. pts. 35, 385) [hereinafter Order No. 888], *order on reh'g*, Order No. 888-A, F.E.R.C. STATS. & REGS. ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 F.E.R.C. ¶ 61,248, 62 Fed. Reg. 64,688 (1997), *order on reh'g*, Order No. 888-C, 82 F.E.R.C. ¶ 61,046 (1998), *aff'd in relevant part sub nom.*, *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom.*, *New York v. FERC*, 535 U.S. 1 (2002).

4. Order No. 889, *Open Access Same-Time Information System and Standards of Conduct*, F.E.R.C. STATS. & REGS. ¶ 31,035 (1996), 61 Fed. Reg. 21,737 (1996) (to be codified at 18 C.F.R. pt. 37), *order on reh'g*, Order No. 889-A, F.E.R.C. STATS. & REGS. ¶ 31,049 (1997), 62 Fed. Reg. 12,484 (1997), *order on reh'g*, Order No. 889-B, 81 F.E.R.C. ¶ 61,253 (1997).

Accordingly, Order No. 888 required all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to . . . file open access non-discriminatory transmission tariffs containing, at a minimum, the non-price terms and conditions set forth in the Order, and . . . functionally unbundle wholesale power services. Under functional unbundling, the public utility must: (1) take transmission services under the same tariff of general applicability as do others; (2) state separate rates for wholesale generation, transmission, and ancillary services; and (3) rely on the same electronic information network that its transmission customers rely on to obtain information about its transmission system when buying or selling power.⁵

In Order No. 888, the FERC clarified the extent of its authority under the Energy Policy Act of 1992 to order public utilities to provide transmission service.⁶ Under the Federal Power Act (FPA), the FERC enjoyed federal jurisdiction over wholesale, interstate transmissions of electricity while jurisdiction over retail electricity transactions was reserved to states. However, in Order No. 888, the “FERC concluded . . . that it has authority over the rates, terms and conditions of transmission in interstate commerce of electricity, including transmission of electricity destined for sale at retail.”⁷ Several parties appealed in the courts, but the United States Supreme Court in *New York v. FERC* upheld FERC’s assertions regarding the extent of its jurisdiction over transmission.⁸

The FERC, in Order No. 888, also began to mold the shape of ISOs, which it encouraged the industry to create as a vehicle to hold control of transmission facilities. At that time the California and PJM markets had ISO proposals pending. The Commission believed that ISOs “have great potential to assist us and the industry to help provide regional efficiencies, to facilitate economically efficient pricing, and, especially in the context of power pools, to remedy undue discrimination and mitigate market power.”⁹ It stated regarding ISOs:

[W]e see many benefits in ISOs, and encourage utilities to consider ISOs as a tool to meet the demands of the competitive marketplace. As a further precaution against discriminatory behavior, we will continue to monitor electricity markets to ensure that functional unbundling adequately protects transmission customers. At the same time, we will analyze all alternative proposals, including formation of ISOs, and, if it becomes apparent that functional unbundling is inadequate or unworkable in assuring nondiscriminatory open access transmission, we will reevaluate our position and decide whether other mechanisms, such as ISOs, should be required.¹⁰

The Commission required ISOs to develop mechanisms to coordinate with neighboring control areas to ensure reliability and the provision of transmission

5. Order No. 2000, *Regional Transmission Organizations*, [Regs. Preambles 1996–2000] F.E.R.C. STATS. & REGS. ¶ 31,089, at p. 30,995 (2000), 65 Fed. Reg. 809 (2000) (to be codified at 18 C.F.R. pt. 35) [hereinafter Order No. 2000], *order on reh’g*, Order No. 2000-A, F.E.R.C. STATS. & REGS. ¶ 31,092, 65 Fed. Reg. 12,088 (2000) [hereinafter Order No. 2000-A], *aff’d sub nom.*, Pub. Util. Dist. No. 1 v. FERC, 272 F.3d 607 (D.C. Cir. 2001).

6. SUEDEEN G. KELLY, MODRALL, SPERLING, ROEHL, HARRIS & SISK, P.A., FERC PROPOSALS AND ORDERS ON STANDARD MARKET DESIGN AND REGIONAL TRANSMISSION ORGANIZATIONS (2003), available at <http://library.findlaw.com/2003/Mar/6/132780.html> [hereinafter FERC PROPOSALS AND ORDERS].

7. *Id.* (citing Order No. 888, *supra* note 3, at pp. 31,694–95).

8. FERC PROPOSALS AND ORDERS, *supra* note 6 (citing *New York v. FERC*, 535 U.S. 1 (2002)). The Court agreed with FERC that whether FERC has jurisdiction over bundled retail transmission is a difficult issue that did not need to be decided in the case before it.

9. Order No. 888, *supra* note 3, at p. 31,652.

10. *Id.* at p. 31,655.

services that cross system boundaries. It determined that non-discriminatory open access transmission service, including access to transmission information, and stranded cost recovery, were the most critical components of a successful transition to competitive wholesale markets.¹¹

The Commission provided the industry with guidance on ISO formation in the form of eleven principles to be used to assess ISO proposals submitted to the Commission.¹² "These principles [address] the ISO's governance, independent structure, reliability and operations, efficiency of management, fostering of economic efficiency in use of and investment in generation, transmission, and consumption, provision of electronic information systems, regional coordination and dispute resolution process[.]"¹³

The first two principles concern the ISO's structure. Principle 1 states that "[t]he ISO's governance should be structured in a fair and nondiscriminatory manner."¹⁴ Thus, "the ISO must be independent of individual market participants, as well as all classes of participants, including transmission owners and end users."¹⁵ Moreover, the RTO structure must preclude any class of participants from exercising any control in the decision-making process. Under Principle 2, "[a]n ISO and its employees should have no financial interest in the economic performance of any power market participant. An ISO should adopt and enforce strict conflict of interest standards."¹⁶ In addition, any agreements between an ISO and generation or transmission owners must be at arm's length.

Principle 3 through Principle 6 relate to the Commission's objectives of promoting open access to transmission and ensuring short-term reliability of the grid. Under Principle 3, "[a]n ISO should provide open access to the transmission system and all services under its control at non-pancaked rates pursuant to a single . . . tariff that applies to all eligible users in a non-discriminatory manner."¹⁷ In addition, "all transmission should be scheduled by the ISO on the section of the grid which it controls."¹⁸ Under Principle 4, "[a]n ISO should have the primary responsibility in ensuring short-term reliability of grid operations."¹⁹ "[A]n ISO should oversee the maintenance of all transmission facilities under its control, including routine maintenance contracted out to third parties."²⁰ In addition, "an ISO may play a role in reliability planning."²¹ Under Principle 5, "[a]n ISO should have control over the operation of interconnected transmission facilities within its region."²² "The Commission determined that absent control over all of the interconnected transmission facilities within the ISO's region, the presence of non-member

11. Order No. 888, *supra* note 3, at p. 31,655.

12. *Id.* at p. 31,730. For a full summary of the eleven principles for evaluating ISO proposals, see Independent System Operators, 4 Energy Law and Transactions (MB) 89-1 (2002) [hereinafter Energy Law and Transactions].

13. Energy Law and Transactions, *supra* note 12, at 89-13.

14. *Id.* (quoting Order No. 888, *supra* note 3, at p. 31,730).

15. Energy Law and Transactions, *supra* note 12, at 89-13.

16. *Id.* at 89-13 (quoting Order No. 888, *supra* note 3, at p. 31,731).

17. Energy Law and Transactions, *supra* note 12, at 89-14 (quoting Order No. 888, *supra* note 3, at p. 31,731).

18. *Id.* at 89-14 (quoting Order No. 888, *supra* note 3, at p. 31,731).

19. Energy Law and Transactions, *supra* note 12, at 89-14 (quoting Order No. 888, *supra* note 3, at p. 31,731).

20. *Id.* at 89-14.

21. Energy Law and Transactions, *supra* note 12, at 89-14.

22. *Id.* (quoting Order No. 888, *supra* note 3, at p. 31,731).

transmission facilities within the region could undermine the effectiveness of the ISO.”²³ Finally, under Principle 6, “[a]n ISO should identify constraints on the system and be able to take operational actions to relieve those constraints within the trading rules established by the governing body.”²⁴ In promoting efficient trading, “an ISO may find it necessary to exercise some level of operational control over generation facilities.”²⁵ In situations where trading is limited by transmission constraints over some interfaces, “an ISO must act in accordance with trading rules composed by the governing body.”²⁶

Principle 7 through Principle 10 concern appropriate management practices at an ISO. Under Principle 7, “[t]he ISO should have appropriate incentives for efficient management and administration and should procure the services needed for such management and administration in an open competitive market.”²⁷ The “operational functions which may be performed by an ISO include: ‘determination of appropriate system expansions, transmission, maintenance, administering transmission contracts, operation of a settlements system, and operation of an energy auction.’”²⁸ Principle 8 states that “[a]n ISO’s transmission and ancillary services pricing policies should promote the efficient use of and investment in generation, transmission, and consumption.”²⁹ The Commission “recommended that transmission pricing proposals addressing network congestion be consistent with the Commission’s Transmission Pricing Policy Statement.”³⁰

Along with pricing policies, the Commission requires that an ISO perform . . . studies . . . necessary to identify transmission constraints on its system, loop flow impacts between the ISO’s system and those of neighboring systems, [and] additional factors which might have an effect on system operation or expansion.

Principle 9 requires that an ISO “make transmission system information publicly available . . . via an electronic information network.”³² Finally, Principle 10 requires that “[a]n ISO should develop mechanisms to coordinate with neighboring control areas.”³³

The last principle, Principle 11, requires that an ISO “establish an [alternative dispute resolution] process to resolve disputes in the first instance.”³⁴ It urges the ISO to “establish rules and procedures by which parties may voluntarily resolve technical, financial and other issues, thereby thwarting the filing of complaints with [the] FERC.”³⁵

In Order No. 888, the Commission established that taking steps to qualify as “a properly constituted ISO is a means by which public utilities can comply with

23. Energy Law and Transactions, *supra* note 12, at 89-14.

24. *Id.* (quoting Order No. 888, *supra* note 3, at p. 31,731).

25. Energy Law and Transactions, *supra* note 12, at 89-15.

26. *Id.*

27. Energy Law and Transactions, *supra* note 12, at 89-15 (quoting Order No. 888, *supra* note 3, at p. 31,731).

28. *Id.* at 89-15 (quoting Order No. 888, *supra* note 3, at pp. 31,731-32).

29. Energy Law and Transactions, *supra* note 12, at 89-15 (quoting Order No. 888, *supra* note 3, at p. 31,732).

30. *Id.* at 89-15.

31. Energy Law and Transactions, *supra* note 12, at 89-15 to -16.

32. *Id.* at 89-16 (quoting Order No. 888, *supra* note 3, at p. 31,732).

33. Energy Law and Transactions, *supra* note 12, at 89-16 (quoting Order No. 888, *supra* note 3, at p. 31,732).

34. *Id.* at 89-16 (quoting Order No. 888, *supra* note 3, at p. 31,732).

35. Energy Law and Transactions, *supra* note 12, at 89-16.

the Commission's non-discriminatory transmission tariff requirements."³⁶ The Commission has authority under Order No. 888 to determine whether or not a proposed or existing ISO meets the various standards and requirements encompassed in that Order. If the FERC found that an entity fails to satisfy ISO criteria, however, it may determine that the ISO no longer qualifies as an ISO for purposes of Order No. 888. In *California Independent System Operator Corp. v. FERC*, the FERC was concerned that the CAISO's governing board, which was chosen according to a method dictated by California statute, conflicted with the principle of Order No. 888 that ISOs should be independent of market participants.³⁷ In response, the FERC issued an order directing CAISO to implement FERC's own procedures to replace CAISO's board. However, the United States Court of Appeals for the District of Columbia Circuit overturned FERC's order, stating that FERC has no authority to replace the selection method or membership of the governing board of an ISO. The Court ruled: "If [the] FERC concludes that CAISO lacks the independence or other necessary attributes to constitute an ISO for purposes of Order No. 888, then it need not approve CAISO as an ISO."³⁸ The Court reminded the FERC that "Order No. 888 is merely a regulation."³⁹ "If California stubbornly refuses to make CAISO conform to FERC's requirements for ISOs, then FERC can declare that CAISO is not an ISO, or threaten to do so."⁴⁰

III. ORDER NO. 2000

After Order No. 888 was issued, the electric industry underwent sweeping restructuring activity, including the development in many states of retail competition, increasing "divestiture of generation plants by traditional electric utilities, a significant increase in the number of mergers among traditional electric utilities and among electric utilities and gas pipeline companies, large increases in the number of power marketers and independent generation facility developers entering the marketplace, and the establishment of [ISOs]"⁴¹ The Commission observed that since Order No. 888 was issued, there were both successful and unsuccessful efforts to establish ISOs and other regional entities to operate transmission facilities in various regions. While it was encouraged by the success of some of those efforts, the Commission concluded "that the results have been inconsistent, and much of the country's transmission facilities remain outside of an operational regional transmission institution."⁴²

On May 13, 1999, the Commission issued a Notice of Proposed Rulemaking (NOPR) on Regional Transmission Organizations, stating that the "traditional means of grid management . . . may be inadequate to support the efficient and reliable operation that is needed for the continued development of competitive electricity markets."⁴³ The Commission, on December 20, 1999, issued Order No. 2000, which adopted a Final Rule supporting development of

36. Order No. 888, *supra* note 3, at p. 31,730.

37. *Cal. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395 (D.C. Cir. 2004).

38. *Id.* at 404.

39. *Cal. Indep. Sys.*, 372 F.3d at 404.

40. *Id.*

41. Order No. 2000, *supra* note 5, at p. 30,992.

42. *Id.* at p. 30,999.

43. Notice of Proposed Rulemaking, *Regional Transmission Organizations*, [1999-2003 Proposed Regs.] F.E.R.C. STATS. & REGS. ¶ 32,541, at p. 33,685, 64 Fed. Reg. 31,389 (1999).

RTOs that generally followed the approach of the NOPR.⁴⁴ The Commission's policy with regard to RTOs is contained in Order No. 2000.

In Order No. 2000, the Commission concluded that "it is clear that RTOs are needed to resolve impediments to fully competitive markets" based on issues such as "undue discrimination and market power, . . . economic and engineering issues affecting reliability, operational efficiency, and competition in the electric industry."⁴⁵ The Commission's objective was "for all transmission-owning entities" in the Nation, including non-public utility entities, "to place their transmission facilities under the control of [appropriate] RTOs in a timely manner."⁴⁶ The Commission continued to believe that voluntary RTO participation would be most appropriate.⁴⁷

The Commission noted that during the course of the Order No. 888 proceeding, it was urged "to require generation divestiture or structural institutional arrangements such as regional" ISOs to better achieve non-discrimination.⁴⁸ While "ISOs had the potential to provide significant benefits," the Commission believed that "efforts to remedy undue discrimination should begin by requiring the less intrusive functional unbundling approach."⁴⁹ However, in Order No. 2000, the Commission recognized that "[s]ubsequent to issuance of Order No. 888, it has become apparent that several types of regional transmission institutions, in addition to the kinds of ISOs approved to date, may also be able to provide the benefits attributed to ISOs in Order No. 888."⁵⁰

All RTOs are required to abide by four core characteristics and eight key functions. The core characteristics are independence, scope and regional configuration, operational authority, and short-term reliability.⁵¹

Characteristic 1. Independence

The Commission underscored that "the principle of independence is the bedrock upon which the ISO must be built" and that "an RTO [must] be independent in both reality and perception."⁵²

RTOs [must] satisfy three conditions: (i) the RTO, its employees, and any non-stakeholder directors must not have any financial interests in any market participants; (ii) the RTO must have a decision-making process that is independent of control by any market participant or class of participants; and (iii) the RTO must have [the] exclusive

right to make Section 205 filings that apply to the rates, terms, and conditions of transmission services over the facilities operated by the RTO.⁵³

44. Order No. 2000, *supra* note 5, at pp. 31,046–168.

45. *Id.* at p. 31,033.

46. Order No. 2000, *supra* note 5, at p. 31,033.

47. *Id.* at pp. 31,033–34.

48. Order No. 2000, *supra* note 5, at p. 30,996.

49. *Id.*

50. Order No. 2000, *supra* note 5, at p. 30,996.

51. The summary of RTO functions and characteristics contained herein is largely a recitation of the functions and characteristics as described in *Report of the Committee on Electric Utility Regulation*, 22 ENERGY L.J. 425, 427–30 (2001) [hereinafter *Report of the Committee*]. See also Order No. 2000, *supra* note 5, at pp. 31,046–168.

52. Order No. 2000, *supra* note 5, at p. 31,061.

53. *Report of the Committee*, *supra* note 51, at 428. See Order No. 2000, *supra* note 5, at pp. 31,061–75.

Characteristic 2. Scope and Regional Configuration

"An RTO must be of sufficient scope to operate reliably and permit the RTO to effectively perform its required functions and to support efficient and nondiscriminatory power markets."⁵⁴ Proposed RTO boundaries are evaluated based on several factors, such as whether they will "facilitate performing essential RTO functions and achieving RTO goals[,]" whether they will "encompass one contiguous geographic area[,]" and whether they will "deter the exercise of market power"⁵⁵

Characteristic 3. Operational Authority

"An RTO must have operational authority for all transmission facilities under its control and . . . must be the security coordinator for its region."⁵⁶ The Commission provided examples of operational control, such as "switching transmission elements into and out of operation in the transmission system"⁵⁷

Characteristic 4. Short-Term Reliability

RTOs must be responsible for short-term reliability. The Commission clarified what is meant by short-term as "intended to cover transmission reliability responsibilities short of grid capacity enhancement. It includes all time periods, including but not limited to 'real-time,' necessary for the RTO to satisfy its reliability responsibilities, up to the planning horizon."⁵⁸

The eight key functions of an RTO are tariff administration and design, congestion management, parallel path flows, ancillary services, Open Access Same-Time Information System (OASIS), market monitoring, planning and expansion, and interregional cooperation:

Function 1. Tariff Administration and Design

"The RTO must be the sole provider of transmission service and sole administrator of its own open access transmission tariff. The RTO must have sole authority to evaluate and approve all requests for transmission service including requests for new interconnections" and the tariff must not result in pancaked rates.⁵⁹

Function 2. Congestion Management

The RTO must ensure the development and operation of market mechanisms to manage congestion. . . . [T]he responsibility for operating these market mechanisms must reside either with the RTO itself or with another entity that is independent of market participants.⁶⁰

54. Order No. 2000, *supra* note 5, at p. 31,076.

55. *Report of the Committee*, *supra* note 51, at 428.

56. *Id.*

57. *Report of the Committee*, *supra* note 51, at 428.

58. *Id.* at 428 (quoting Order No. 2000, *supra* note 5, at p. 31,103).

59. *Report of the Committee*, *supra* note 51, at 429.

60. *Id.*

Function 3. Parallel Path Flows

The RTO must implement procedures to address parallel path flow issues within its region by the RTO's startup date, and implement procedures to address the same issues with other regions within three years of the RTO's startup date.⁶¹

Function 4. Ancillary Services

The RTO must serve as the "provider" of last resort for all ancillary services required by Order No. 888 and subsequent orders. . . . [A]ll market participants must continue to have the option of self-supplying or acquiring ancillary services from third parties subject to general restrictions [under] Order No. 888 and subsequent orders.⁶²

Function 5. OASIS, TTC and ATC

"The RTO must be the single open access same time information system (OASIS) site administrator for all transmission facilities under its control, however, . . . the RTO can contract out the OASIS responsibilities to another independent entity."⁶³ Other provisions apply to Total Transmission Capacity (TTC) and Available Transmission Capacity (ATC).⁶⁴

Function 6. Market Monitoring

"RTO proposals must include a market monitoring plan that identifies . . . appropriate monitoring activities [that] the RTO, or an independent monitor, will perform."⁶⁵ The plan must meet several requirements and objectives, such as "ensur[ing] that there is objective information about the markets that the RTO operates or administers and a vehicle to propose appropriate action regarding any opportunities for efficiency improvement, market design flaws, or market power identified by such information"⁶⁶

Function 7. Planning and Expansion

The RTO must have ultimate responsibility for both transmission planning and expansion within its region and coordinate its efforts with appropriate state authorities. . . . [Unless] the RTO [can] demonstrate that an alternative proposal is consistent with or superior to the [following] three requirements[,] [t]he RTO must: (i) encourage market-motivated operating and investment actions for preventing and relieving congestion; (ii) accommodate efforts . . . to create multi-state agreements to review and approve new transmission facilities. . . and (iii) file a plan with the Commission . . . that will ensure that it meets the overall planning and expansion requirement no later than three years after initial operation.⁶⁷

Function 8. Interregional Coordination

"The RTO must develop mechanisms to coordinate its activities with other regions An RTO proposal must explain how the RTO will ensure the

60. *Report of the Committee*, supra note 51, at 429.

62. *Id.* at 429.

63. *Report of the Committee*, supra note 51, at 429–30.

64. *Id.* at 430.

65. *Report of the Committee*, supra note 51, at 430.

66. *Id.* at 430.

67. *Report of the Committee*, supra note 51, at 430.

integration of reliability and market interface practices.”⁶⁸ The FERC allowed “[i]ndustry participants . . . flexibility in structuring RTOs that satisfy the minimum characteristics and functions.”⁶⁹

[A]ll public utilities (with the exception of those participating in an approved regional transmission entity that conforms to the Commission’s [eleven] ISO principles [set forth in Order No. 888]) that own, operate or control interstate transmission facilities [were directed to] file with the Commission . . . a proposal for an RTO with the minimum characteristics and functions to be operational by December 15, 2001, or, alternatively, a description of efforts to participate in an RTO, any existing obstacles to RTO participation, and any plans to work toward RTO participation.⁷⁰

IV. STANDARD MARKET DESIGN NOTICE OF PROPOSED RULEMAKING

In July 2002 the FERC issued a NOPR Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design (SMD NOPR) that would restructure the entire U.S. wholesale electricity market.⁷¹ However, at this point RTO development was well underway and the FERC, prior to issuing its NOPR on SMD, offered guidance steering the development of RTOs. In the time leading up to the SMD NOPR, “[t]he FERC ha[d] before it numerous ongoing proceedings involving RTO proposals” at various stages of development.⁷² The Commission held a public conference on RTO issues including the need for clear, standardized transmission tariff design and market rules.⁷³ The FERC on November 7, 2001 issued an Order stating its goals and providing general guidance on how it intended to proceed with RTO filings and other related efforts.⁷⁴

The FERC divided the RTO development effort into two tracks. “The first track [would] resolve issues relating to geographic scope and governance of . . . RTOs, [which would] be addressed in [the] pending RT[O] dockets following consultation with state commissioners”⁷⁵ The second track would take place under the SMD NOPR docket to resolve “business and process issues needed for organizations to accomplish the functions of Order No. 2000.”⁷⁶ The FERC noted that it would take

several immediate steps to move the RTO process along these [two] tracks[,] [including]: (1) a broader definition of how certain RTO functions will be fulfilled; (2) better state/federal dialogue; (3) further cost/benefit studies; (4) identification of areas where standardization is called for; and (5) creation of a time line for RTO implementation.⁷⁷

The Commission underscored the importance of state involvement, stating that state commissioner participation confirmed that FERC and the states “must work

68. *Id.*

69. Order No. 2000, *supra* note 5, at p. 30,994.

70. “A public utility that is a member of an existing transmission entity that has been approved by the Commission as in conformance with the eleven ISO principles set forth in Order No. 888 [was required to] make a filing no later than January 15, 2001.” Order No. 2000, *supra* note 5, at p. 30,994.

71. SMD NOPR, *supra* note 1.

72. *Electricity Market Design and Structure*, 97 F.E.R.C. ¶ 61,146 at p. 61,632 (2001).

73. *Id.*

74. 97 F.E.R.C. ¶ 61,146, at p. 61,632 (2001).

75. *Id.*

76. 97 F.E.R.C. ¶ 61,146, at p. 61,632.

77. *Id.* at pp. 61,632–33.

closely [together] to create a seamless national market.”⁷⁸ While the November 7, 2001 Order was not a final ruling on the development of RTOs, it set out FERC’s goals and a process for their creation.

In the SMD NOPR, the FERC articulated its plan under the FPA to remove impediments to competitive wholesale electricity markets, and included a resource adequacy requirement.⁷⁹ The FERC proposed

to amend its regulations under the [FPA] to modify the *pro forma* [OATT] established under . . . Order No. 888 to remedy remaining undue discrimination in the provision of interstate transmission services and in other industry practices, and to assure just and reasonable rates within and among regional power markets. [It] propose[d] to require all public utilities with open access transmission tariffs to file modifications to their tariffs to reflect non-discriminatory, standardized transmission service and standardized wholesale electric market design.⁸⁰

FERC’s SMD was adamantly opposed by many interest groups, including consumer groups and state commissions. Notably, much of the opposition came from areas of the country that are without RTOs. “[R]egulators from the Pacific Northwest, South and states that ha[d] an abundance of low-cost power . . . oppose[d] the SMD proposal and asked that it be withdrawn.”⁸¹ In a “joint filing by state regulators . . . and consumer groups from 22 states, [one group] argued that [the FERC] unlawfully intrudes on the states’ authority to oversee retail electricity markets.”⁸² Another “group of consumers’ counsels and consumer groups from Colorado, New Mexico, Rhode Island, and Utah [argued] that the traditional cost-of-service approach to retail and wholesale ratemaking [was] working” in their states, and that they saw no need to make a change.⁸³ The president of the Alabama Public Service Commission summed up its objections to SMD, arguing: (1) SMD would “adversely affect [consumers] in low-cost states[;]”⁸⁴ (2) SMD would “usurp long-term state regulatory authority[;]”⁸⁵ (3) SMD would “favor power marketers and IPPs[;]”⁸⁶ and (4) SMD would “shift[] costs to retail customers and away from those who caused the costs to be incurred.”⁸⁷

Implementation of SMD was put on hold due to opposition in Congress. Congress asked the Department of Energy (DOE) to study the merits of FERC’s SMD proposal. On April 30, 2003, the DOE issued a report on its independent study to assess various potential impacts of the proposed rulemaking.⁸⁸ In response to comments on the SMD NOPR, the Commission on April 28, 2003, issued a Wholesale Power Market Platform White Paper laying out a revised

78. 97 F.E.R.C. ¶ 61,146, at p. 61,633.

79. SMD NOPR, *supra* note 1, at p. 32,563.

80. *Id.* at p. 32,563.

81. Foster Electric Report, *Many State Commissions Demand that FERC Withdraw Proposed SMD Rule, But Others Just Want Initiative Tweaked* (Dec. 4, 2002), available at <http://www.fosterassociates.com/electric/article.asp?id=951> [hereinafter Foster Electric Report].

82. *Id.*

83. Foster Electric Report, *supra* note 81.

84. Lori A. Burkhardt, *Regulators’ Forum: A Fight Over Market Design*, PUB. UTILS. REP., Nov. 15, 2002, available at <http://www.pur.com/pubs/4049.cfm>.

85. *Id.*

86. Burkhardt, *supra* note 84.

87. *Id.*

88. U.S. DEP’T OF ENERGY, REPORT TO CONGRESS: IMPACTS OF THE FEDERAL ENERGY REGULATORY COMMISSION’S PROPOSAL FOR STANDARD MARKET DESIGN, DOE/S-0138 (Apr. 30, 2003).

proposal for building a wholesale electric market. In that White Paper, the FERC

recognized the need for additional changes to its proposed rule and indicated that: (1) it would not assert jurisdiction over the transmission rate component of bundled retail service; (2) nothing in the Final Rule would change state authority over resource adequacy requirements and regional transmission planning requirements; (3) regional state committees would determine how firm transmission rights should be allocated to current customers; (4) implementation would be tailored to each region and modifications would be allowed to benefit customers in each region; (5) each RTO would be required to have a clear transmission cost recovery policy outlined in its tariff; and (6) it would eliminate the proposed requirement that public utilities create or join an independent entity, but would require them to join an RTO or independent system operator (ISO).⁸⁹

On July 19, 2005, the FERC issued an order terminating the SMD docket.⁹⁰ The FERC stated that the SMD NOPR had been overtaken by events because "[s]ince issuance of the SMD NOPR, the electric industry has made significant progress in the development of voluntary RTOs and ISOs"⁹¹ The Commission noted that such progress in the electric industry "has allowed interested parties, through region-specific proceedings, to shape the development of independent entities to reflect the needs of each particular region."⁹²

V. RTO AND ISO ACTIVITIES

Many of the developments described in this article will affect all of the RTOs and ISOs in the United States. However, a brief history of the formation of individual RTOs is useful to identifying and understanding particular issues with which some RTOs and ISOs will be faced. Some key developments that are not addressed separately in later sections below are also discussed.

A. PJM Interconnection

PJM Interconnection (PJM) began operating as an ISO on March 1, 1998,⁹³ after operating for many years as a "tight" power pool.⁹⁴ By order issued December 20, 2002, the Commission granted PJM full RTO status.⁹⁵ PJM's operations, as its name suggests, originally focused primarily in the states of Pennsylvania, New Jersey, Maryland, and the District of Columbia, although PJM has been sporadically expanding ever since it first became operational. PJM is now at a stage where it is digesting its most recent acquisitions, having more than doubled its size in the past year to where its footprint now includes more than twenty percent of the U.S. economy.⁹⁶ In May of 2004, PJM integrated the Illinois-based Commonwealth Edison system. In October of 2004,

89. *Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design*, 112 F.E.R.C. ¶ 61,073 at P 4 (2005). See also FED. ENERGY REGULATORY COMM'N, WHITE PAPER: WHOLESALE POWER MARKET PLATFORM, Docket No. RM01-12-000 (Apr. 28, 2003), available at www.feris.ferc.gov/idmws/common/opennat.asp?fileID=9686957 [hereinafter WHITE PAPER].

90. 112 F.E.R.C. ¶ 61,073 at P 1.

91. *Id.*

92. 112 F.E.R.C. ¶ 61,073 at P 6.

93. *PJM Interconnection*, 81 F.E.R.C. ¶ 61,257 (1997), *motion to defer tariff implementation granted*, 81 F.E.R.C. ¶ 61,379 (1997), *order on reh'g and clarification*, 92 F.E.R.C. ¶ 61,282 (2000).

94. A "tight" pool dispatches the generation resources of its members on an integrated basis to minimize production costs.

95. *PJM Interconnection, L.L.C.*, 101 F.E.R.C. ¶ 61,345 (2002).

96. Press Release, PJM Interconnection, Dominion Successfully Integrated into PJM (May 1, 2005).

American Electric Power and Dayton Power & Light joined PJM followed by the integration of Duquesne Light Company on January 1, 2005. Finally, on May 1, 2005, PJM began operating Dominion Resources' transmission assets in Virginia and North Carolina. While these acquisitions have presented a myriad of issues, none of these issues has to date presented insurmountable problems and transmission operations have continued without major difficulty.⁹⁷

While PJM is rather large now, for some time the Commission, PJM, Midwest ISO (MISO), and their market participants have anticipated the day when PJM and MISO may become an integrated market.⁹⁸ By order issued March 3, 2005,⁹⁹ the Commission modified and conditionally accepted a joint PJM/MISO filing which described how they proposed to coordinate their energy markets when MISO's energy market commenced on April 1, 2005. In compliance with that order¹⁰⁰ on October 31, 2005, MISO and PJM filed a description of, and a schedule for, the steps they plan to take to further coordinate their various markets, including their energy markets. However, in their compliance filing,¹⁰¹ MISO and PJM make clear that they do not recommend the simple creation of a single market since "the incremental benefits of a single market are overwhelmingly outweighed by [the] costs" of creating and operating that market.¹⁰²

Meanwhile, PJM has been fine tuning other aspects of its tariff. In a series of orders,¹⁰³ the Commission considered, and ultimately accepted as modified, tariff provisions proposed by PJM to alter its transmission planning process so that it "would identify transmission expansions that are needed to support competition."¹⁰⁴ Under these tariff provisions

PJM will first identify areas that are experiencing unhedgeable congestion (*i.e.*, the increased generation costs incurred because of a transmission constraint). PJM will then initiate a one-year period (the market window) for the market to provide a solution for areas experiencing unhedgeable congestion, such as a merchant developer proposing to construct an upgrade. If the market does not bring about a solution during this period, PJM will determine the costs and benefits of constructing an upgrade, and, if it determined that the benefits of constructing an

97. See, e.g., *Report of the Electric Utility Regulation Committee*, 26 ENERGY L.J. 217, 220-23 (2005) (discussing the issues presented by the integration of American Electric Power Corporation (AEP) into PJM, including the objections of the Kentucky Public Service Commission and the Virginia State Corporation Commission. In addition, the parties are now sorting through the issues related to the recovery of expenses incurred by PJM to develop the systems and infrastructure necessary to integrate AEP, Commonwealth Edison Company and the Dayton Power and Light Company into PJM). See also *Am. Electric Power Service Corporation*, 111 F.E.R.C. ¶ 61,180 (2005), *order granting reh'g, dismissing compliance filing, and establishing hearing and settlement judge procedures*, 113 F.E.R.C. ¶ 61,050 (2005).

98. See, e.g., *Alliance Companies*, 100 F.E.R.C. ¶ 61,137 (2002), *order addressing requests for clarification*, 102 F.E.R.C. ¶ 61,214 (2003), *order on reh'g and providing clarification*, 103 F.E.R.C. ¶ 61,274 (2003), *order granting clarification in part and denying request for reh'g*, 105 F.E.R.C. ¶ 61,215 (2003), *appeal docketed sub nom. Am. Elec. Power Serv. Corp. v. FERC*, No. 03-1223 (D.C. Cir. Aug 1, 2003).

99. *Midwest Independent Transmission System Operator, Inc.*, 110 F.E.R.C. ¶ 61,226 (2005).

100. *Id.*

101. *Midwest Independent Transmission System Operator, Inc.*, Docket Nos. ER04-375-017 and ER04-375-018, at 49 (Oct. 31, 2005) (complying with the Commission's order of March 3, 2005, *Midwest Independent Transmission System Operator, Inc.*, 110 F.E.R.C. ¶ 61,226 (2005)).

102. Letter from Midwest ISO, Inc., and PJM Interconnection, L.L.C., to the Honorable Magalie Roman Salas, Sec'y, Fed. Energy Regulatory Comm'n (Oct. 31, 2005) (transmittal letter regarding informational filing in response to the Commission's order of March 3, 2005, Docket No. ER04-375-017 and ER04-375-018).

103. *PJM Interconnection, L.L.C.*, 101 F.E.R.C. ¶ 61,345 (2002); *PJM Interconnection, L.L.C.*, 104 F.E.R.C. ¶ 61,124 (2003); *PJM Interconnection, L.L.C.*, 105 F.E.R.C. ¶ 61,123 (2003); *PJM Interconnection, L.L.C.*, 109 F.E.R.C. ¶ 61,067 (2004); and *PJM Interconnection, L.L.C.*, 110 F.E.R.C. ¶ 61,377 (2005).

104. 110 F.E.R.C. ¶ 61,377 at P 2.

upgrade would outweigh the costs, PJM would propose construction of a transmission upgrade. PJM would also make a determination as to the parties who would bear the costs of constructing the upgrade (*i.e.*, the upgrade's beneficiaries).¹⁰⁵

B. ISO New England Inc.

Before ISO New England Inc. (ISO-NE) became an RTO, the New England Power Pool (NEPOOL) had assumed responsibility for all aspects of the day-to-day operation of the region's bulk power system. Formed in 1971, NEPOOL was responsible for "assur[ing] that the bulk electric power supply of the New England region [was] provided reliably and economically through central dispatch of virtually all of the generation and transmission facilities in New England as a single control area."¹⁰⁶ On December 31, 1996, as supplemented February 14, April 18, May 1 and June 5, 1997, NEPOOL filed a comprehensive restructuring proposal that included an interim ISO Agreement.¹⁰⁷ On June 25, 1997, the FERC issued an order conditionally authorizing establishment of an ISO by the NEPOOL.¹⁰⁸

ISO-NE and the New England transmission owners¹⁰⁹ filed a request for recognition as an RTO on October 31, 2003.¹¹⁰ The filing built upon earlier efforts to establish a Commission-approved RTO. One proposal was submitted on January 16, 2001,¹¹¹ and a second proposal was filed on August 23, 2002.¹¹² On March 24, 2004, ISO-NE was granted RTO status subject to fulfillment of certain requirements identified by the Commission.¹¹³ In an order issued on February 10, 2005 the Commission "address[ed] a series of related compliance filings, informational filings, proposed tariff revisions, and requests for rehearing and/or clarification of prior orders concerning the proposal . . ."¹¹⁴ It found that, with the satisfaction of additional compliance requirements and the resolution of certain related proceedings and reserved issues, ISO-NE was authorized to begin operation as an RTO effective February 1, 2005.¹¹⁵

ISO-NE is in the process of designing and implementing several critical market design changes that are currently being addressed at the Commission and in the courts. These include the introduction of a Locational Installed Capacity (LICAP) mechanism, appropriate compensation of RMR resources, the filing of IC Requirements (*i.e.*, "a projection of the minimum amount of capacity required to serve load reliably in the New England region"), development of an Ancillary

105. *Id.* at P 3.

106. *New England Power Pool*, 79 F.E.R.C. ¶ 61,374, at p. 62,576 (1997).

107. *Id.* at p. 62,577.

108. 79 F.E.R.C. ¶ 61,374, at p. 62,576.

109. Bangor Hydro Electric Company, Central Maine Power Company, NSTAR Electric & Gas Corporation, New England Power Company, Northeast Utilities Service Company, The United Illuminating Company, and Vermont Electric Power Company.

110. *Request for Approval of a Regional Transmission Organization for New England*, Docket Nos. RT04-2-000 and ER04-116-000 (Oct. 31, 2003).

111. *See Bangor Hydro-Electric Company*, 96 F.E.R.C. ¶ 61,063, at p. 61,275 (2001). In the RTO 2001 Order, the Commission rejected a proposed RTO scope limited to the New England region.

112. The proposal was submitted jointly by ISO-NE and NYISO. While negotiations surrounding the joint effort ultimately failed, in a notice of withdrawal filed on November 22, 2002, ISO-NE and NYISO expressed their commitment to continue to work collaboratively toward RTO formation.

113. *See ISO New England Inc.*, 106 F.E.R.C. ¶ 61,280 (2004); *see also ISO New England Inc.*, 109 F.E.R.C. ¶ 61,147 (2004).

114. *ISO New England Inc.*, 110 F.E.R.C. ¶ 61,111 at P 1 (2005).

115. *Id.*

Services Market Project, and revisions to the market rules instituting revised cold weather procedures.¹¹⁶ Each of these developments is discussed in detail in section VI, below.

ISO-NE has also been active with other filings. It participated in numerous proceedings regarding RMR agreements such as recent filings concerning Bridgeport Energy, LLC and Berkshire Power Co, LLC. On February 18, 2005, as supplemented on May 20, 2005, Bridgeport Energy, LLC (Bridgeport) filed a proposed unexecuted RMR agreement between Bridgeport and ISO-NE, for Bridgeport's generation facility located in Southwest Connecticut. The FERC conditionally accepted the proposed RMR agreement and established hearing and settlement judge procedures.¹¹⁷ Requests for rehearing of that Order were denied. On June 30, 2005, Berkshire Power Co, LLC (Berkshire) filed an unexecuted Cost-of-Service Agreement with ISO-NE.¹¹⁸ Berkshire filed on October 6, 2005 a modified Cost-of-Service Agreement which incorporates certain changes ordered by the Commission in a September 6, 2005 Order that conditionally accepted the agreement and established hearing and settlement procedures.¹¹⁹ On February 2, 2006, the Commission denied a petition for rehearing of the September 6, 2005 Order that was filed by Massachusetts Municipal Wholesale Electric Company.¹²⁰ The proliferation of RMR agreements in New England and in other regions is discussed in further detail below.

The ISO has also filed tariff revisions, such as an amendment to NEPOOL Market Rule 1 and the Transmission, Markets and Service Tariff.¹²¹ "The Amendment removes the current prohibition against Participants submitting a negative price per MW for Financial Transmission Rights [(FTR)] in FTR Auctions."¹²² The Commission accepted the amendment, effective April 1, 2005.¹²³ ISO-NE has also submitted revisions to Market Rule 1 with respect to partial delisting of ICAP resources.¹²⁴ The revisions would allow "generators to partially de-list as qualified Installed Capacity . . . resources and make sales of capacity and firm, non-recallable energy available to neighboring control areas."¹²⁵ In that proceeding, the Commission on March 31, 2005 conditionally accepted the tariff filing "and direct[ed] ISO-NE and NEPOOL to make a further

116. *ISO New England, Inc.*, 112 F.E.R.C. ¶ 61,254 at P 2 (2005).

117. *Bridgeport Energy, LLC*, 112 F.E.R.C. ¶ 61,077 (2005), *reh'g denied*, 113 F.E.R.C. ¶ 61,311 (2005).

118. *Unexecuted Cost-of-Service Agreement Between Berkshire Power Company, LLC and ISO New England Inc.*, Docket No. ER05-1179-000 (June 30, 2005).

119. *Berkshire Power Company, LLC*, 112 F.E.R.C. ¶ 61,253 (2005).

120. *Berkshire Power Company, LLC*, 114 F.E.R.C. ¶ 61,099 (2006).

121. Letter from ISO New England Inc. and New England Power Pool, to the Honorable Magalie Roman Salas, Sec'y, Fed. Energy Regulatory Comm'n (Jan. 26, 2005) (transmittal letter regarding amendment to Market Rule 1, FERC Electric Tariff No. 3, Docket No. ER05-492-000).

122. *Id.*

123. See Letter from Anna V. Cochrane, Division of Tariffs and Market Development—East, Fed. Energy Regulatory Comm'n, to James Douglas, ISO New England Inc. (Mar. 3, 2005) (regarding submitted amendment to Market Rule 1, FERC Electric Tariff No. 3, Docket No. ER05-492-000).

124. Letter from ISO New England Inc. and New England Power Pool, to the Honorable Magalie Roman Salas, Sec'y, Fed. Energy Regulatory Comm'n (Jan. 31, 2005) (transmittal letter regarding revisions to Market Rule 1—Partial De-listing of ICAP Resources, Docket No. ER05-531-000).

125. *New England Power Pool*, 110 F.E.R.C. ¶ 61,396 at P 1 (2005), *order on reh'g*, 112 F.E.R.C. ¶ 61,278 (2005). The Commission expressed concern that several provisions in the proposal would limit the benefits of partial de-listing, and requested that ISO-NE address these issues in a separate compliance filing. See *ISO New England, Inc.*, 113 F.E.R.C. ¶ 61,157 (2005).

filing to address certain issues raised by the parties to [the] proceeding”¹²⁶

C. New York ISO

The New York ISO (NYISO) is an outgrowth of the New York Power Pool, which was formed by New York’s eight largest electric utilities following the Northeast Blackout of 1965. On June 30, 1998, the Commission issued an order authorizing the establishment of NYISO.¹²⁷ NYISO began to administer its open access tariff on November 18, 1999, and formal transfer to NYISO of operational control over the New York State transmission facilities occurred on December 1, 1999.¹²⁸ NYISO has not filed for RTO status and apparently has no current plans to do so.¹²⁹

Operationally, the last year has been relatively uneventful for NYISO. NYISO’s Independent Market Advisor’s 2004 State of the Market Report indicates that there were relatively few price corrections in the New York market during 2004, in part because “no major enhancements were made to the market software in 2004.”¹³⁰ The Independent Market Advisor concluded: “[w]hile the overall state of the market in 2004 was good, there were continuing issues relating to market rules and operations, many of which have been addressed with the implementation of the Real-Time Scheduling (“RTS”) system that occurred in February, 2005.”¹³¹

The RTS system replaces NYISO’s much-criticized Balancing Market Evaluation software and “co-optimizes energy, reserves[,] and regulation, and commits resources as necessary to meet the demands of the next hour.”¹³² A report by NYISO’s Independent Market Advisor reviewing the early performance of the RTS system is anticipated in the near future.

D. Midwest ISO

The Midwest ISO (MISO) is a relatively new entity among the ISOs and RTOs here examined, although by order issued December 20, 2001, the Commission found that MISO’s proposal to become an RTO was the first one to satisfy the requirements of Order No. 2000.¹³³ MISO “controls more than 100,000 miles of transmission lines and more than 100,000 megawatts of electric generation over approximately 1.1 million square miles” in a 15-state region in the Midwestern United States.¹³⁴ MISO began selling regional transmission

126. 110 F.E.R.C. ¶ 61,396 at P 1.

127. *Cent. Hudson Gas & Elec. Corp.*, 83 F.E.R.C. ¶ 61,352 (1998), *order on reh’g*, 87 F.E.R.C. ¶ 61,135 (1999).

128. On December 22, 2003 the Commission clarified that NYISO’s Order No. 2000 RTO compliance filing docket (Docket No. RT01-95 and all its subdockets) had been terminated. *RTO Informational Filings*, 105 F.E.R.C. ¶ 61,327 at P 8 (2003).

129. *Id.*

130. POTOMAC ECON., LTD., 2004 STATE OF THE MARKET REPORT: NEW YORK ISO iii (July 2005), available at http://www.ksg.harvard.edu/hepg/Papers/NYISO_2004_state_of_the_market_report.pdf [hereinafter POTOMAC ECON., LTD.].

131. *Id.*

132. POTOMAC ECON., LTD., *supra* note 130, at xxiii.

133. *Midwest Indep. Transmission Sys. Operator, Inc.*, 97 F.E.R.C. ¶ 61,326 (2001), *reh’g denied*, 103 F.E.R.C. ¶ 61,169 (2003).

134. *Industry restructuring FAQ’s*, WESTERN AREA POWER ADMINISTRATION, (October 24, 2003) available at <http://www.wapa.gov/newsroom/cct/2003/oct24/25no221a.htm>.

service under its FERC-approved tariff ("Day 1" operations) on Feb. 1, 2002.¹³⁵

Although MISO implemented its Day 2 energy market on April 1, 2005 without any disruption of service, there have been a number of problems resulting from its implementation that have required the attention of MISO, its market participants, and the Commission. On June 30, 2005, Commission Staff issued a study on generator offers made during Day 2 implementation which found that the large number of potentially excessive generator offers identified by MISO's Independent Market Monitor during the Day 2 period in question "[w]ere mainly the result of [several] practical problems [facing] participants in the new market, including difficulties establishing accurate reference [price] levels and communications problems"¹³⁶ On June 28, 2005, the Commission issued an order¹³⁷ which granted a "complaint filed by Alliant alleging that MISO "improperly defined two of Alliant's transmission service entitlements, resulting in the denial of an allocation of FTRs for those entitlements."¹³⁸ Similarly, on November 2, 2005, the Wisconsin Electric Power Company filed a complaint alleging that MISO "failed to allocate financial transmission rights sufficient to cover all of [its] eligible Network Resource entitlements"¹³⁹ Meanwhile, Louisville Gas and Electric Company has sought to withdraw from MISO, asserting that its Independent Transmission Organization/Reliability Coordinator proposal will satisfy Order No. 888 requirements at a lower cost than would continued membership in MISO.¹⁴⁰ And, the MISO market participants continue to wade through the thorny issues related to the grandfathering of existing transmission agreements.¹⁴¹

E. California ISO

Authority to establish the California ISO (CAISO) was conditionally granted by Commission order issued November 26, 1996.¹⁴² Filings requesting such authority were made by California's three largest investor-owned electric utilities, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company, at the direction of the Public Utilities Commission of the State of California to implement the decision of that

135. *Id.*

136. FED. ENERGY REGULATORY COMM'N, REPORT ON GENERATOR OFFERS IN THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR MARKET LAUNCH (June 2005).

137. *Alliant Energy Corporate Servs., Inc.*, 111 F.E.R.C. ¶ 61,499 at P 1 (2005).

138. *Id.*

139. *Wisc. Elec. Power Co.*, 114 F.E.R.C. ¶ 61005 at P 1 (2006).

140. Letter from Clifford S. Sikora et al., Attorney for LG&E Energy, LLC, Louisville Gas and Electric Company, and Kentucky Utilities Company, to the Honorable Magalie Roman Salas, Sec'y, Fed. Energy Regulatory Comm'n (Oct. 7, 2005) (transmittal letter regarding Section 203 and 205 Filing, Docket Nos. EC06-04-000 and ER06-20-000) [hereinafter Louisville Transmittal Letter]. Louisville asserts that its withdrawal from MISO will not have an adverse impact on MISO's operations, energy markets, or membership, since, among other things, its system represents a mere "drop in the bucket" compared to MISO's regional system and, therefore, Louisville's withdrawal will only increase market concentration slightly. In addition, Louisville maintains that it is located on the "border" of the MISO footprint and that, therefore, it is not essential for MISO's connectivity needs. *Id.* at 27-28. Various parties, including MISO, have vigorously protested Louisville's proposal. In its protest of Louisville's filing, MISO asserts, among other things, that Louisville's proposal does not adequately manage loop flow, lacks market power monitoring, does not eliminate pancaked rates, and inaccurately assesses the costs and benefits to Louisville's customers and others of Louisville's participation in MISO. Motion to Intervene and Protest of the Midwest Independent System Operator, Inc., FERC Docket Nos. EC06-4-000, ER06-20-000 (Nov. 15, 2005).

141. See, e.g., *Midwest Indep. Transmission Sys. Operator, Inc.*, 107 F.E.R.C. ¶ 61,191 (2004).

142. *Pac. Gas and Elec. Co.*, 77 F.E.R.C. ¶ 61,204 (1996).

Commission and of the California Legislature requiring the restructuring of the electric utility industry in California. The CAISO received conditional authorization to commence operations by Commission order issued October 30, 1997.¹⁴³ The CAISO is not an RTO and its Order No. 2000 compliance filing proceeding, Docket No. RT01-85-000, has been terminated.¹⁴⁴

The CAISO is attempting to reconstruct its market to avoid the combination of price spikes and blackouts that plagued it previously. And the refund cases relating to prior California markets are heading for final resolution which should provided much needed regulatory certainty for all market participants.¹⁴⁵

California also appears to be on the verge of obtaining the desperately needed Path 15 transmission upgrade.

In an order issued on December 2, 2004, the Commission accepted for filing Trans-Elect NTD Path 15, LLC's transmission revenue requirement and proposed Transmission Owner Tariff . . . , suspended it for a nominal period, to become effective upon commencement of commercial operation of the Path 15 Upgrade, subject to refund and subject to the outcome of the proceeding established in Docket No. PL05-5-000.¹⁴⁶

In that order, "[t]he Commission also established hearing and settlement judge procedures."¹⁴⁷ In the PL05-5 proceeding, the Commission issued a Policy Statement on Income Tax Allowances that concluded that an "allowance for partnerships or similar pass-through entities that hold interests in a regulated public utility . . . should be permitted on all [such] interests . . . if the owner of that interest has an actual or potential income tax liability on the public utility income earned through the interest."¹⁴⁸ The Commission believed that this policy statement would "facilitate[] investment in public utility assets."¹⁴⁹

With regard to the development of California market design, the Commission has provided guidance in a series of orders dating back to 2002,¹⁵⁰

143. *Pac. Gas and Elec. Co.*, 81 F.E.R.C. ¶ 61,122 (1997).

144. *See San Diego Gas & Elec. Co.*, 112 F.E.R.C. ¶ 61,155 (2005). By letter dated September 14, 2005, the CAISO informed the Commission that it has no objection to the Commission's termination of its RT01-85-000 Order No. 2000 compliance filing docket. Thus, it does not appear that the CAISO will obtain, or even seek to obtain, RTO status for the foreseeable future. Governance issues concerning the CAISO appear to be nearing resolution given the issuance of recent Commission orders approving the CAISO's proposed changes to its Board of Governors selection process. *See Cal. Indep. Sys. Operator Corp.*, 112 F.E.R.C. ¶ 61,010 (2005), *reh'g dismissed*, 112 F.E.R.C. ¶ 61,337 (2005). *See also Cal. Indep. Sys. Operator Corp.*, 112 F.E.R.C. ¶ 61,001 (2005).

145. *Report of the Electric Utility Regulatory Committee*, 26 ENERGY L.J. 217, 231-33 (providing a useful summary of recent developments in California in this regard). In addition, under section 1824 of EPCA 2005, the FERC was required to submit to Congress a report describing actions taken by the Commission to conclude its investigation of unreasonable charges incurred by California during the electricity crisis and to ensure that refunds to California are paid. The FERC submitted its report to Congress on December 27, 2005. FED. ENERGY REGULATORY COMM'N, THE COMMISSION'S RESPONSE TO THE CALIFORNIA ELECTRICITY CRISIS AND TIMELINE FOR DISTRIBUTION OF REFUNDS (2005), <http://www.ferc.gov/legal/staff-reports/comm-response.pdf>.

146. *Trans-Elect NTD Path 15, LLC*, 109 F.E.R.C. ¶ 61,249 (2004), *reh'g denied*, 111 F.E.R.C. ¶ 61,140 at P 1 (2005), *order on compliance filing*, 112 F.E.R.C. ¶ 61,202 (2005), *order accepting compliance filing*, 113 F.E.R.C. ¶ 61,162 (2005).

147. *Trans-Elect NTD Path 15, LLC*, 109 F.E.R.C. ¶ 61,249 (2004), *reh'g denied*, 111 F.E.R.C. ¶ 61,140 at P 1 (2005), *order on compliance filing*, 112 F.E.R.C. ¶ 61,202 (2005), *order accepting compliance filing*, 113 F.E.R.C. ¶ 61,162 (2005).

148. *Inquiry Regarding Income Tax Allowances*, 111 F.E.R.C. ¶ 61,139 (2005).

149. *Id.*

150. *Cal. Indep. Sys. Operator Corp.*, 100 F.E.R.C. ¶ 61,060 (2002), *Cal. Indep. Sys. Operator Corp.*, 105 F.E.R.C. ¶ 61,140 (2003), *Cal. Indep. Sys. Operator Corp.*, 107 F.E.R.C. ¶ 61,274 (2004), *Cal. Indep. Sys.*

the most recent being an Order on Rehearing issued on September 19, 2005.¹⁵¹ On February 9, 2006, CAISO filed at the FERC its Market Redesign and Technology Upgrade Tariff (MRTU Tariff) for implementation November 1, 2007.¹⁵² The CAISO's new tariff includes several prominent changes to its market design and market mitigation, including Congestion Revenue Rights to allow Market Participants to manage their costs of Congestion, the implementation of a day-ahead market, an hour-ahead scheduling process, and a real-time market using locational marginal pricing and security-constrained unit commitment to dispatch resources and manage congestion.¹⁵³

F. Southwest Power Pool

[Southwest Power Pool (SPP)] is an Arkansas non-profit corporation, serving more than four million customers in a 250,000 square mile area, covering all or part of the States of Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma, and Texas. [Its] membership includes 14 investor-owned utilities, six municipal systems, eight generation and transmission cooperatives, three [S]tate authorities, one [F]ederal power marketing agency, two independent power producers, and 16 power marketers.¹⁵⁴

Since 1997, SPP has been the reliability coordinator in its region. SPP filed a request for recognition as an RTO on October 15, 2003.¹⁵⁵ On February 10, 2004,¹⁵⁶ SPP was conditionally granted RTO status and in a series of FERC orders issued in 2004, was directed to complete certain additional steps identified by the Commission.¹⁵⁷ By order issued October 1, 2004,¹⁵⁸ the Commission granted SPP status as an RTO, subject to further compliance filings. In a second order issued on that day, the Commission accepted a Joint Operating Agreement (JOA) between SPP and the MISO on an interim basis.¹⁵⁹

G. ERCOT

The Electric Reliability Council Of Texas (ERCOT) is the Regional Reliability Council responsible for ensuring the reliability of the bulk electric system that serves 85% of the electrical load within the State of Texas.¹⁶⁰ It is

Operator Corp., 108 F.E.R.C. ¶ 61,254 (2004), *Cal. Indep. Sys. Operator Corp.*, 110 FERC ¶ 61,041 (2005), *Cal. Independent System Operator*, 112 F.E.R.C. ¶ 61,013 (2005).

151. *Cal. Indep. Sys. Operator Corp.*, 112 F.E.R.C. ¶ 61,310 (2005), *reh'g pending*.

152. California Independent System Operator Corp.'s Electric Tariff Filing to Reflect Market Redesign and Technology Upgrade, FERC Docket No. ER06-615-000 (2006).

153. *Id.*; Letter from Sidney M. Davies et al., *Cal. Indep. Sys. Operator Corp.*, to the Honorable Magalie Roman Salas, Sec'y, Fed. Energy Regulatory Comm'n at 2-4 (2006) (transmittal letter regarding MRTU Tariff, Docket No. ER06-615-000).

154. *Sw. Power Pool, Inc.*, 109 F.E.R.C. ¶ 61,010 at P 3 (2004).

155. RTO Proposal of Southwest Power Pool, Inc., FERC Docket Nos. RT04-1-000, ER04-48-000 (Oct. 15, 2003).

156. *Sw. Power Pool, Inc.*, 106 F.E.R.C. ¶ 61,110 (2004), *order on reh'g*, 109 F.E.R.C. ¶ 61,010 (2004).

157. *Id.* See also *Sw. Power Pool, Inc.*, 108 F.E.R.C. ¶ 61,003 (2004), *order on reh'g*, 110 F.E.R.C. ¶ 61,138 (2005); *Sw. Power Pool, Inc.*, 109 F.E.R.C. ¶ 61,009 (2004), *order on reh'g*, 110 F.E.R.C. ¶ 61,137 (2005); *Sw. Power Pool, Inc.*, 110 F.E.R.C. ¶ 61,046 (2005); *Sw. Power Pool, Inc.*, 111 F.E.R.C. ¶ 61,118 (2005), *order on reh'g*, 112 F.E.R.C. ¶ 61,319 (2005); *Sw. Power Pool, Inc.*, 113 F.E.R.C. ¶ 61,014 (2005).

158. *Sw. Power Pool, Inc.*, 109 F.E.R.C. ¶ 61,009 (2004), *order on reh'g*, 110 F.E.R.C. ¶ 61,137 (2005).

159. *Sw. Power Pool, Inc.*, 109 F.E.R.C. ¶ 61,008 (2004).

160. Notice of Proposed Rulemaking, *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards, Comments of The Electric Reliability Council of Texas*, F.E.R.C. STATS. & REGS. ¶ 32,587, 70 Fed. Reg. 53,117 (2005).

also subject to the oversight of the Public Utility Commission of Texas (PUCT). It is a single point of control, intra-state Interconnection organized on an Interconnection-wide basis. Single point of control operations utilizing competitive capacity and energy markets to maintain the reliability of the ERCOT grid began in mid 2001. ERCOT's only connections to electric grids outside of its Interconnection consist of a 220 MW DC tie to the Southwest Power Pool, a 600 MW DC tie to the Southeast Electric Reliability Council and a 35 MW DC tie to the Mexico electric grid. ERCOT is not subject to FERC jurisdiction for rate matters under FPA sections 205 and 206.¹⁶¹ ERCOT's membership consists of Municipal Utilities, Rural Electric Cooperatives and River Authorities, Investor Owned Utilities, Independent Power Producers, Power Marketers, Retail Electric Providers and Customers.

VI. CURRENT ISSUES

Many RTO and ISO developments are at the forefront of electric industry policymaking that has been ongoing at the Commission and in the judiciary. Numerous rulemakings and litigated proceedings are pending at FERC, which is working toward developing policies that foster competitive markets while also implementing new rules and regulations prompted by the EPAct 2005. Although an in depth analysis of all pertinent issues is not included here, the following survey will inform practitioners of several important issues that will have a significant impact on the energy industry.

A. *Development of Capacity Markets*

The stability of the electric system requires capacity resources adequate to meet peak demand (plus a reserve margin) while capable of withstanding the unexpected loss of transmission and/or generation.¹⁶² The main purpose of a capacity market is to "ensure that adequate capacity is committed on a daily or seasonal basis to meet system load and reserve requirements."¹⁶³ Capacity markets have been introduced in NYISO and ISO-NE, and CAISO is currently considering developing a capacity market. PJM on October 1, 1998 initiated monthly and multi-monthly capacity markets, and introduced daily capacity markets in 1999.¹⁶⁴

1. New York ISO

The Installed Capacity (ICAP) market in New York was created administratively to ensure the reliability of the electricity system. The New York State Reliability Council (NYSRC) had set New York State's minimum Capacity requirement at 118% of the State's peak load, and the NYISO had set the New York City and Long Island LICAP Requirements at 80% and 95% of their peak Load levels, respectively.¹⁶⁵ The LICAP requirements would be met with

161. See e.g., *Dynegy Power Mktg., Inc.*, 111 F.E.R.C. ¶ 61,411 at P 13 (2005).

162. Anna Creti & Natalia Fabra, *Capacity Markets for Electricity* (Ctr. for the Study of Energy Mkts., Working Paper No. 124, 2003), available at <http://www.ucei.berkeley.edu/ucei/PDF/csemwp124.pdf> [hereinafter *Capacity Markets for Electricity*].

163. *Id.*

164. *Capacity Markets for Electricity*, *supra* note 163, at 4.

165. Letter from New York ISO, Inc., to the Honorable Magalie Roman Salas, Sec'y, Fed. Energy Regulatory Comm'n (Mar. 21, 2003) (filing letter regarding revisions to the ISO Market Administration and Control Area Services Tariff: ICAP Demand Curve, Docket No. ER03-647-000) [hereinafter ICAP Demand

Resources located within those areas, while the capacity quantities above the LICAP Requirement levels up to the minimum 118% level could be procured from anywhere in the state and from external resources.¹⁶⁶ The requirements are allocated among Load Serving Entities (LSEs) in proportion to the Load they serve. LSEs may meet their requirements by self-supplying the capacity from their own resources, or with capacity acquired through bilateral contracts, or by purchasing the capacity through the auctions conducted by the NYISO.¹⁶⁷ The ICAP market established a vertical demand curve at the minimum requirement level extending up to the deficiency price level (three times the annual cost of installing a new gas turbine).¹⁶⁸

On March 21, 2003, the NYISO introduced revisions to its Market Administration and Control Services Tariff to incorporate an ICAP Demand Curve in the Installed Capacity/Unforced Capacity market.¹⁶⁹ NYISO was prompted to replace the existing rules for ICAP because those rules created a market that produced volatile prices and did not signal investment beyond the minimum ICAP requirement.¹⁷⁰ NYISO explained that the volatility occurred because the market value of ICAP rose above \$200 per kW-year (the deficiency charge) when aggregate ICAP supply was less than the 118 percent requirement, and fell to nearly \$0 when aggregate ICAP supply exceeded 118 percent.¹⁷¹ According to NYISO, this volatility increased risk and reduced the ability of new generation to obtain financing.¹⁷²

The ICAP Demand Curve was designed to replace the existing vertical demand curve.¹⁷³ Under the proposal, the ICAP requirement would no longer be fixed at 118% of peak load. Rather, it would vary depending on the market price for ICAP determined using a demand curve in a monthly auction.¹⁷⁴ The proposed ICAP Demand Curve would replace the vertical demand curve with a sloped demand curve, and would be used to determine both the amount of the ICAP requirement as the market price for ICAP:

[A]t a capacity of 118 percent of peak load, the demand price would be set equal to the annualized cost of a new peaking unit for each area. The demand price would gradually fall for amounts of capacity beyond 118 percent of peak load until, at 132 percent of peak load, the demand price would be \$0. In addition, the demand price would gradually rise above the annualized cost of a new peaking unit for levels of capacity below 118 percent of peak load to a maximum of about two times the annualized cost of the new peaking unit.¹⁷⁵

Each month, capacity suppliers would bid into an ICAP auction creating a supply curve. The point of intersection between the supply curve and the demand curve would determine the quantity and price of required ICAP.¹⁷⁶

In an order issued on May 20, 2003 (May 20 Order), the Commission

Curve].

166. *Id.*

167. ICAP Demand Curve, *supra* note 166.

168. *Id.*

169. ICAP Demand Curve, *supra* note 166.

170. *N.Y. Indep. Sys. Operator, Inc.*, 103 F.E.R.C. ¶ 61,201 at P 3 (2003), *order on reh'g*, *N.Y. Indep. Sys. Operator, Inc.*, 105 F.E.R.C. ¶ 61,108 (2003).

171. *Id.* at P 4.

172. 103 F.E.R.C. ¶ 61,201 at P 4.

173. *Id.* at P 2.

174. 103 F.E.R.C. ¶ 61,201 at P 2.

175. *Id.* at P 5.

176. *N.Y. Indep. Sys. Operator, Inc.*, 103 F.E.R.C. ¶ 61,201 at P 7 n.7 (2003).

accepted NYISO's proposal, with modifications.¹⁷⁷ The FERC agreed with the NYISO that the proposal would encourage greater investment in generation capacity and improve reliability by reducing the volatility of ICAP revenues.¹⁷⁸ The Commission concluded that:

[a]lthough the potential costs and benefits cannot be known with certainty . . . the NYISO's analyses adequately demonstrate that the proposal will benefit customers because it will encourage the construction of new generation, will encourage the formation of long-term bilateral transactions, and, as modified . . . will reduce incentives to withhold capacity.¹⁷⁹

The Commission acknowledged that the development of ICAP was based on "some measure of judgment, since there has been no experience with this new mechanism."¹⁸⁰ Accordingly, NYISO was directed to file detailed evaluations of the demand curve and its implementation annually for three years.

Among several issues raised on rehearing, Industrial Consumers¹⁸¹ argued that, because the purpose of the demand curve was to encourage new supplies, the case law governing incentive rates must apply.¹⁸² Such a ratemaking standard would "requir[e] the Commission to demonstrate that the rate increase is no more than necessary to achieve its purpose of encouraging investment in new generation facilities in New York State."¹⁸³ The Commission denied rehearing on the issue of standard of review. It distinguished incentive ratemaking cases which involved incremental rate increases levied upon all customers for the basic commodity, unlike the instant case where ICAP charges would be incurred by an LSE only if the LSE needs to procure additional ICAP in the spot market.¹⁸⁴ Even if such cases would apply, the Commission stated that its conclusion would remain the same: "the ICAP demand curve is clearly necessary . . . to reduce volatility in the ICAP and energy markets, provide better price signals for investment in new generation, and reduce incentives to withhold capacity."¹⁸⁵

New York Municipals argued that the Commission's failure to address arguments that NYISO did not justify its demand curve as either a cost-based rate or as a market-based rate conflicts with the just and reasonable standard under section 205 of the FPA.¹⁸⁶ The Commission rejected this argument, noting that "the key to whether a rate is just and reasonable is the end result, not the particular formula used to reach that result."¹⁸⁷ Several parties also argued that the ICAP Demand Curve would increase electricity costs in New York without

177. *Id.* at P 3.

178. 103 F.E.R.C. ¶ 61,201 at P 13.

179. *Id.* at P 36. For example, the Commission rejected the Supplemental Supply Fee aspect of the proposal, noting that it may create the potential for capacity withholding when the system does not clear to meet the 118 percent minimum. 103 F.E.R.C. ¶ 61,201 at P 67.

180. *Id.* at P 36.

181. Two groups sought rehearing of the May 20 Order. Industrial Consumers include the Electricity Consumers Council (ELCON), the NEPOOL Industrial Customer Coalition, and the PJM Industrial Consumer Coalition. NY Municipals comprise the municipal electric utilities of the Village of Bergen, Village of Freeport, Jamestown Board of Public Utilities, Village of Rockville Centre and Salamanca Board of Public Utilities. In addition, KeySpan Ravenswood, LLC filed a request for clarification. *N.Y. Indep. Sys. Operator, Inc.*, 105 F.E.R.C. ¶ 61,108 at P 7 nn.7-8 (2003).

182. *Id.* at P 16.

183. *Elec. Consumers Res. Council v. FERC*, 407 F.3d 1232, 1234 (D.C. Cir. 2005).

184. 105 F.E.R.C. ¶ 61,108 at P 19.

185. *Id.* at P 20.

186. 105 F.E.R.C. ¶ 61,108 at P 17.

187. *Id.* at P 21.

providing additional benefits.¹⁸⁸ However, the Commission found that “increased stability in ICAP revenues will contribute to, but not exclusively influence, the construction of new generation, which over time should provide for savings and benefits that are difficult to quantify at the present time.”¹⁸⁹ The Commission was not persuaded to reverse its ruling in the May 20 Order. It accepted NYISO’s compliance filing and proposed tariff revisions and denied the requests for rehearing and clarification.

The Electricity Consumers Resource Council (ELCON), filed a petition for review of FERC’s May 20 Order and the Rehearing Order in the United States Court of Appeals for the District of Columbia Circuit. ELCON, which represents industrial consumers of electricity, argued that the Commission’s orders violated the “just and reasonable” ratemaking standard and were arbitrary and capricious.¹⁹⁰ In addition, ELCON urged the court to apply a heightened standard of review for incentive ratemaking cases.¹⁹¹

The court denied ELCON’s petition for review. It found that there was no basis for a heightened standard of review because the rate design does not impose an incremental rate increase above traditional cost-based rates, but rather seeks to stabilize rates to promote the development and retention of installed capacity.¹⁹² Moreover, the court found that “[i]nstead of granting ‘above-cost premiums to suppliers of capacity,’ the ICAP Demand Curve restructures ICAP prices to ‘more realistically reflect . . . the economic value of capacity reserves’ and to ‘send better price signals to encourage the construction of generation before a shortage occurs.’”¹⁹³

ELCON argued that the Commission failed to consider several other arguments, including: (1) that the ICAP charges were too high and that the demand curve slope was too gradual; (2) that the demand curve would impose increased costs on consumers; (3) that the demand curve would not encourage investment in new generation; (4) that the demand curve replaces price volatility with quantity volatility; and (5) the Commission failed to consider alternatives to the demand curve.¹⁹⁴ The Court found that the Commission adequately considered and rejected all of these arguments.¹⁹⁵ Accordingly, the Court denied ELCON’s petition for review, finding that FERC’s approval of NYISO’s rate design was supported by substantial evidence in the record and was not arbitrary and capricious.¹⁹⁶

NYISO won at the court house in *ELCON*, but has NYISO’s ICAP Demand Curve been successful in practice? Has it encouraged construction of needed new generation in New York in the more than two years that it has been in effect? Some say that “the jury is still out.”¹⁹⁷ In contrast, some observers,¹⁹⁸

188. *N.Y. Indep. Sys. Operator, Inc.*, 103 F.E.R.C. ¶ 61,201 at P 37 (2003).

189. *Id.* at P 44.

190. *Elec. Consumers Res. Council v. FERC*, 407 F.3d 1232, 1234 (D.C. Cir. 2005).

191. *Id.*

192. *Elec. Consumers*, 407 F.3d at 1234, 1237.

193. *Id.* at 1238 (internal citations omitted).

194. *Elec. Consumers*, 407 F.3d at 1239–42.

195. *Id.*

196. *Elec. Consumers Res. Council v. FERC*, 407 F.3d 1232, 1239–42 (D.C. Cir. 2005).

197. Transcript of Oral Argument at 78:10–13; 89:25, 90:3–4, *In Re Devon Power LLC* (Sept. 20, 2005) (Docket No. ER03-563-000) [hereinafter Transcript of Oral Argument].

198. See, e.g., John Reese, Dir. of Econ. Dev. and Policy Coordinator, N.Y. Pub. Serv. Comm’n, Statement at the Meeting of the Northeast Chapter of the Energy Bar Association (Oct. 31, 2005). Mr. Reese’s statements were offered as his personal observations and were not meant to convey any position taken by the

while indicating that there has been “no direct line” between the demand curve and construction, and that construction would not occur based on the existence of the curve alone, relate that conversations with equity investors indicate that the curve is “an important factor” in their deliberations concerning whether to invest in new generation. NYISO’s ICAP mechanism and how it compares with the proposals of other RTOs are discussed further below.

2. ISO New England Inc.

ISO-NE designed its proposed LICAP mechanism to address Reliability Compensation Issues (RCIs) identified in the New England region.¹⁹⁹ The ISO’s LICAP mechanism has been the subject of highly complex litigation at the Commission for the past two years. The proceeding began²⁰⁰ on February 26, 2003, when Devon Power LLC, Middletown Power LLC, Montville Power LLC, Norwalk Power LLC and NRG Power Marketing Inc. (collectively, NRG) filed four cost-of-service RMR agreements to provide compensation for generating units necessary for reliability in Southwest Connecticut and Connecticut. In an order issued April 25, 2003,²⁰¹ the Commission rejected the RMR agreements and directed the ISO “to file no later than March 1, 2004 for implementation no later than June 1, 2004, a mechanism that implements location or deliverability requirements in the ICAP or resource adequacy market . . . so that capacity within DCAs may be appropriately compensated for reliability.”²⁰²

On March 1, 2004, the ISO submitted its LICAP mechanism (March 1 Filing) pursuant to the Commission’s April 25 Order.²⁰³ Its key objectives were to design a market that provided appropriate incentives for long-term reliability, just and reasonable market outcomes, and reduction of RMR agreements.²⁰⁴ ISO-NE acknowledged that its existing ICAP market suffered from significant problems, many attributed to the vertical demand curve that was used to clear the market:

When installed capacity is close to the reliability requirements, the vertical demand curve causes even small changes in capacity to result in large price swings between near zero and the deficiency charge. These potential price movements, sometimes referred to as “bi-polar” or “binary” pricing, are inherent in any market with a vertical demand curve and supply which is unresponsive in the short term. With a vertical demand curve, capacity payments may drop to zero when there is only slightly more capacity than required.²⁰⁵

The March 1 Filing contained a comprehensive proposal for a LICAP market, including a downward sloping demand curve with specified parameters, four ICAP regions, a five year transition mechanism, market mitigation rules and a detailed clearing auction process.²⁰⁶ The ISO’s March 1 Filing was protested

New York Public Service Commission.

199. See discussion *infra* Section VI.B regarding Reliability Compensation Issues.

200. The procedural history herein is largely a recitation of the Unopposed Joint Procedural History submitted by the parties in the LICAP proceeding. For the full text of the Unopposed Joint Procedural History see *Devon Power LLC*, 111 F.E.R.C. ¶ 63,063 at PP 2–36 (2005).

201. *Devon Power LLC*, 103 F.E.R.C. ¶ 61,082 (2003).

202. *Id.* at P 37. In its order on rehearing of the April 25 Order, the Commission affirmed PUSH bidding, and clarified its section 206 finding. *Devon Power LLC*, 104 F.E.R.C. ¶ 61,123 (2003).

203. 103 F.E.R.C. ¶ 61,082 at P 37.

204. Transcript of Testimony of David LaPlante, *Devon Power LLC* (2004) (FERC Docket No. ER03-563-000) [hereinafter Testimony of David LaPlante].

205. *Id.* at 3–4.

206. Testimony of David LaPlante, *supra* note 205.

by several New England parties, including load and suppliers.²⁰⁷

On June 2, 2004, the Commission issued an order²⁰⁸ which addressed the ISO's March 1 Filing and identified issues to be addressed at a hearing before an Administrative Law Judge (ALJ). It also directed the ISO to submit a filing addressing whether the Commission should revise the ISO's proposal to create a separate import-constrained ICAP region for Southwest Connecticut.²⁰⁹ In that order the FERC deferred implementation of the LICAP proposal until January 1, 2006.

The Commission in the June 2 Order agreed with the overarching concept of a demand curve, but found that more information was necessary to appropriately set the parameters of the demand curve for each LICAP region and established the hearing for that purpose.²¹⁰ The Commission concluded that until LICAP is implemented, it would extend the PUSH mechanism and would consider RMR contracts to ensure that market participants are appropriately compensated for reliability services in the short-term.

In several rounds of testimony, ISO-NE made certain adjustments to its initial proposal filed on March 1, 2004. These adjustments include changes to the price-setting mechanism, use of the "As-Is," rather than the "At Criterion" assumption for computing CTLs, and introduction of a "shortage hours" availability metric to replace the Equivalent Demand Forced Outage Rate (EFORD) metric. The shortage hours metric was intended to take into account the actual availability of each generator in contributing to system reliability during the hours when the system is under most stress. ISO-NE's proposal, as modified, had the following four key characteristics:

1. A demand curve that solves the short and long term RCIs . . . while providing the proper incentives to build the right amount of capacity at the lowest possible cost to consumers;
2. The use of a market-based availability metric to determine which resources should receive LICAP Payments;
3. The deduction from the LICAP demand curve price of the actual energy revenues that would be earned by a benchmark generator to determine the LICAP Payment, based on an *ex ante* rolling 12-month average of the energy rents; and
4. The use of all installed capacity, including mothballed units, net of imports and exports, to determine the supply curve for the market.²¹¹

On June 15, 2005, the presiding ALJ issued an Initial Decision generally approving the LICAP mechanism that ISO-NE initially filed on March 1, 2004. The judge found that ISO-NE's demand curve proposal:

considered as a whole, is responsive to the Commission's directive and provides a just and reasonable result "that will appropriately compensate generators needed for reliability and attract and retain necessary infrastructure to assure long-term

207. *Devon Power LLC*, 111 F.E.R.C. ¶ 63,063 at P 5.

208. *Devon Power LLC*, 107 F.E.R.C. ¶ 61,240 (2004).

209. The Commission instituted an investigation and paper hearing regarding whether a separate energy load zone should be created for Southwest Connecticut, and whether it should be implemented in advance of the implementation of LICAP.

210. The proper method for calculating Capacity Transfer Limits (CTLs), the appropriate method for determining the amount of Capacity Transfer Rights (CTRs) to be allocated, and the proper allocation of CTRs were also set for hearing.

211. Initial Brief of ISO New England Inc., FERC Docket No. ER03-563-000 (Apr. 15, 2005).

reliability" at the lowest cost²¹² to consumers, balancing the interests of both Generators and Load in doing so.

However, the judge declined to adopt ISO-NE's proposed availability metric, stating "at this time, the record supports a finding that the continued use of EFORD to define and measure availability is appropriate."²¹³

Several parties filed briefs on exceptions citing numerous objections to the judge's Initial Decision. Notably, several parties alleged that they were denied the opportunity to present alternatives to ISO-NE's proposed LICAP market design, and that ISO-NE's proposal was too costly to consumers, and thereby unjust and unreasonable.²¹⁴ In addition, several parties²¹⁵ filed petitions for review at the United States Court of Appeals for the First Circuit. The parties sought review of several FERC orders in the LICAP proceeding.²¹⁶ However, on May 5, 2005, the court dismissed without prejudice all dockets²¹⁷ on the basis that the FERC orders at issue were not final.²¹⁸ In addition, the Court stated that it doubted that the petitioners were aggrieved by the orders, and that it was "too early to know whether a LICAP market would be costlier than the undeveloped alternatives."²¹⁹

On July 15, 2005, several state entities²²⁰ requested an oral argument before the Commission on the exceptions to the ALJ's Initial Decision. The Commission granted that request, and an oral argument was held on September 20, 2005. The Commission directed the parties to be prepared to discuss the following questions:

1. Does the proposal (or any alternative approach) provide for just and reasonable wholesale power prices in New England, at levels that encourage needed generation additions?
2. Will the proposal (or any alternative approach) provide adequate assurance that necessary electric generation capacity or reliability will be provided? If so, how?

212. *Devon Power LLC*, 111 F.E.R.C. ¶ 63,063 at P 284 (2005) (quoting *Devon Power LLC*, 107 F.E.R.C. ¶ 61,240 at P 1).

213. *Id.* at P 559 (2005).

214. See, e.g., The Connecticut Parties' Brief On Exceptions, FERC Docket No. ER03-563-000 (July 15, 2005); Brief on Exceptions of the Connecticut Municipal Electric Energy Cooperative and Massachusetts Municipal Wholesale Electric Company, FERC Docket No. ER03-563-000 (July 15, 2005).

215. Petitions for review were filed by NSTAR Electric and Gas Corporation, National Grid USA, Attorney General Thomas F. Reilly, New Hampshire Office of Consumer Advocate, Connecticut Department of Public Utility Control, and Patrick C. Lynch, Attorney General of the State of Rhode Island. See, e.g., Petition for Review, *National Grid USA v. FERC*, No. 03-6330 (1st Cir. Jan. 5, 2005).

216. The appellants sought review of the following Commission orders in the LICAP proceeding: *Devon Power LLC*, 107 F.E.R.C. ¶ 61,240 (2004); *Devon Power LLC*, 109 F.E.R.C. ¶ 61,154 (2004); *Devon Power LLC*, 109 F.E.R.C. ¶ 61,156 (2004); *Devon Power LLC*, 110 F.E.R.C. ¶ 61,315 (2005).

217. The complaint of Patrick C. Lynch, Attorney General of the State of Rhode Island, was filed several months later than the dockets filed by NSTAR and others in the First Circuit. Accordingly, the Court on October 14, 2005 issued a separate judgment dismissing the appeal on the same basis as it had dismissed the NSTAR group of dockets. See Order Entered Granting Motion to Dismiss, *Lynch v. FERC*, No. 05-1765 (Oct. 14, 2005).

218. See, e.g., *NSTAR v. FERC*, No. 04-2549 (2005).

219. *Id.*

220. The moving parties included Connecticut Office of Consumer Counsel, Richard Blumenthal, Attorney General for the State of Connecticut, the Southwestern Area Commerce and Industry Association of Connecticut, Inc., The Connecticut Light and Power Company, by its agent Northeast Utilities Service Company, New England Conference of Public Utilities Commissioners, Maine Public Utilities Commission, Maine Public Advocate, Vermont Department of Public Service and Vermont Public Service Board. Connecticut Parties' Request for Oral Argument, FERC Docket No. ER03-563-030 (July 15, 2005).

3. What are the costs, benefits, and economic impacts of the proposal (or any alternative approach), compared to continued reliance on the status quo, such as the cost of Reliability-Must-Run agreements?²²¹

The oral argument was devoted to discussion of ISO-NE's LICAP proposal and to a discussion of alternatives to LICAP. The parties presented three alternatives to LICAP, including: a New England Resource Adequacy Market (NERAM); a New England Locational Resource Adequacy Market (NELRAM); and Reliability Options (ROs). These alternatives are discussed in further detail below.

In an order issued on October 21, 2005, the Commission gave the parties an opportunity to pursue a settlement on an alternative to the LICAP mechanism, and required that any alternative developed in that process be submitted to the Commission by January 31, 2006.²²² In addition, the Commission directed ISO-NE to submit a compliance filing further detailing its proposal for implementation of a shortage hours availability metric.²²³

On March 6, 2006, a Settlement Agreement resolving all issues was filed at the Commission. The capacity market proposed in the Settlement Agreement establishes a "market-type mechanism" to attract new Resources to meet the growing electric energy needs of the New England region, generally using the Forward Capacity Market (FCM) design recommended by state regulators and consumer representatives.²²⁴ The FCM establishes "competitive auctions for capacity resources to be held three years ahead of their anticipated need."²²⁵ The forward capacity auction (FCA), which will be held annually, will be a descending clock auction. According to the Explanatory Statement, the Settlement Agreement achieves two fundamental objectives: "First, the FCM provides a market structure that will encourage needed new generation to be built. Second, the FCM is designed to allow new capacity to set the clearing price, thus providing a market-based measure of the cost of new entry."²²⁶ At press time, the Commission had not yet issued a final order in this proceeding.

a. Alternatives

Three major alternatives were presented at the oral argument, and two of these had wide support. The major difference between these alternatives and the LICAP approach is that they involve central procurement—the actual acquisition by ISO-NE or some central purchaser of the needed supply, rather than the ISO merely setting the price for the needed supply.

One of the filed alternatives is NERAM, filed by mainly Massachusetts and Connecticut parties. The key elements of the NERAM centralized capacity market include²²⁷ the establishment of the required amount of capacity in the region using established methods and standards; a descending clock auction to procure capacity for the supply period to be held by ISO-NE roughly three-and-a-half years before the capacity supply period; the imposition on the capacity

221. Notice Scheduling Oral Argument, FERC Docket No. ER03-563-000 (Aug. 25, 2005).

222. *Devon Power LLC*, 113 F.E.R.C. ¶ 61,075 at P 1 (2005).

223. *Id.* at P 13.

224. Explanatory Statement, *supra* note 2, at 2.

225. *Id.* at p. 9.

226. Explanatory Statement, *supra* note 2, at p. 3.

227. Statement in Support of The New England Resource Adequacy Market, FERC Docket No. ER03-563-030 (Sept. 13, 2005) [hereinafter *The New England Resource Adequacy Market*].

provider the responsibility to ensure that the bid amount of physical capacity is available during the supply period; the provision of penalties for non-performance; an administered price if there was not sufficient qualified supply to hold a competitive auction; and an availability calculation using the shortage hours proposal developed by ISO-NE for LICAP.

The second alternative to LICAP is NELRAM, which was filed by the state commissions of Rhode Island, New Hampshire, Vermont, and Maine, and which is quite similar to NERAM. The major distinction between the NERAM and the NELRAM proposals is that NELRAM features locational prices, whereas NERAM assumes that New England is best treated as a single unified market.

The third alternative to LICAP is the Reliability Options proposal that is sponsored only by the Connecticut Department of Public Utility Control (CT DPUC), the Connecticut Office of Consumer Counsel, and the Business Council of Fairfield County, which filed testimony on this alternative in the LICAP proceeding. These parties state that although they "support and endorse" NERAM,²²⁸ they "continue to proffer their alternative to LICAP: a Reliability Options market."²²⁹ The Reliability Options market²³⁰ uses an auction-based options product based on the energy market. The option supports generation capacity suppliers' contractual commitments to provide electricity when the options are called. The transacted product is a call option on a megawatt of capacity—backed energy associated with a specified generating facility for a designated supply period. The Reliability Option would consist of two components—a designated strike price and a spot price based on the real-time market. ISO-NE would call Reliability Options during scarcity conditions, when the system is stressed and additional generating resources are needed, i.e., when the Reliability Option's spot price exceeds its strike price. The Reliability Option is both a financial call option and a physical call option because when the Reliability Option is called, the specified generating plant must be generating power or otherwise be available, e.g., supplying reserves. The Reliability Option is a financial option because a generator that sells the Reliability Option must pay the option holder the difference between the spot price and the strike price when the Reliability Option is called.

As was discussed at the oral argument,²³¹ the alternatives to LICAP raise a number of issues including: how to address the near-term need for a capacity market since the alternatives would take some time to develop and implement; what are the appropriate planning and commitment periods; should capacity demand curves be incorporated; and how to address the fact that installed capacity requirements and available capacity are difficult to estimate years in advance despite capacity commitments. In addition, these alternatives present title transfer, market power mitigation, credit verification and risk premium issues.

228. *Id.* at 1.

229. The New England Resource Adequacy Market, *supra* note 228, at 2.

230. *Id.* at 3–4.

231. Transcript of Oral Argument, *supra* note 198, at 187–236.

3. PJM's Reliability Pricing Model Proposal

a. Description of the Proposal

The Reliability Pricing Model's (RPM) primary features include: valuing capacity resources by location; use of a downward-sloping variable resource requirement curve; four-year-forward commitment of capacity resources; and recognizing the added value of capacity resources that preserve operational aspects of reliability. In addition, it allows planned generation, planned and existing demand resources, and planned transmission upgrades to compete on an equal basis with existing generation resources to meet capacity requirements. Finally, it features explicit market power mitigation rules that directly address market-structure concerns of capacity markets.²³²

PJM believes that its RPM proposal is necessary to remedy serious shortcomings in its current capacity market.²³³ PJM asserts that the current market lacks an important locational element, is not providing sufficient financial incentives for supply additions, will not ensure the future reliability of the region, and does not look far enough into the future to secure capacity in time to meet reliability needs. Numerous comments and protests were filed concerning PJM's RPM proposal, together with a few requests for hearing.

b. Comparison With Previously-Filed Installed Capacity Proposals

A critical feature of PJM's RPM proposal is the incorporation of LICAP-like demand curves. PJM proposes to base its demand curves on a downward sloping demand curve with four segments.²³⁴

- (a) a less variable costs, referred to by PJM as the E/AS gross margin), horizontal segment with an ICAP price equal to two times the fixed cost of a turbine if the reserves are less than 96% of the target reserves, minus the net average peak rents of the energy and ancillary services markets (revenues divided by one minus the forced outage rate ($1 - \text{EFORD}$);

(This is similar to ISO-NE's LICAP proposal except that ISO-NE would extend the two times the cost of new entry price to 100% of target reserves (previously OC or Objective Capability, now called IC or Installed Capability in ISO-NE terminology) and ISO-NE subsequently subtracts peak energy rents based on actual prices, and uses a shortage hours availability metric rather than EFORD.)

- (b) another horizontal segment with a zero price if the installed capacity exceeds the desired installed reserve margin of 15% by 5% or more; and

(ISO-NE's proposal is similar except that the zero price is when installed capacity exceeds the desired reserve margin by 15% rather than by 5%.)

- (c) two linear downward sloping segments located between the other two, with the right-hand segment having a shallower slope. The slope of these two lines changes at a point where capacity equals the desired installed reserve margin (IRM) and price equals the cost of new entry (CONE) minus the net average peak rents of the energy and ancillary services markets (the average E/AS gross margin), divided by one minus the forced outage rate (EFORD);

232. Letter from PJM Interconnection LLC, to the Honorable Magalie Salas, Sec'y, Fed. Energy Regulatory Comm'n (Aug. 31, 2005) (transmittal letter submitting new Reliability Pricing Model, Docket Nos. ER05-1410-000, EL05-148-000) [hereinafter RPM Tariff Filing].

233. *Id.* at 4-5.

234. RPM Tariff Filing, *supra* note 233, at 62.

(ISO-NE's proposal is similar except that the slope changes at a somewhat higher level of installed capacity than PJM proposes.) PJM's proposed curve is based on the above except that it is shifted 1% to the right.

PJM's proposal is different than NYISO's or ISO-NE's design in that it recognizes the added value of load following and 30 minute start resources in the auction process, whereas NYISO's curves do not attempt to do so at all and ISO-NE recognizes 30 minute resources through its shortage hours availability metric. PJM also proposes to specifically compare the economics of planned transmission upgrades, which neither NYISO nor ISO-NE does. All three mechanisms are locational, with PJM ultimately calculating separate demand curves for 22 zones. PJM and NYISO rely on auctions to set the price, while ISO-NE would establish a supply curve based on available generation facilities ("iron in the ground"). Unlike NYISO and ISO-NE, PJM's proposal is based upon a four-year-forward commitment of capacity resources.

c. Issues Arising in PJM's RPM Proceeding

Among the issues raised concerning PJM's proposal are issues relating to the effective date of the proposal, what procedures should be used to assess the proposal, what need there is for an ICAP mechanism on PJM's system, whether PJM's proposal impinges on state jurisdiction, and how the proposal should be coordinated with PJM's ongoing transmission planning reform efforts.

Some parties have raised issues concerning price volatility and the need for demand curves, whether RPM will induce new generation and adequately addresses market power, and seams issues with NYISO and MISO.

i. Alternatives

Four major alternatives to PJM's RPM proposal were filed. American Electric Power Service Corporation (AEP) proposes a complete exemption from RPM for vertically integrated regulated utilities as long as the utility can demonstrate that it meets the reliability requirement established as part of its reliability planning process. The Coalition of Consumers for Reliability (Consumers Coalition)²³⁵ filed its Enhanced Integrated Transmission and Capacity Construct (EITCC) model as an alternative to RPM. In PJM's view,²³⁶ a substantial part of the EITCC proposal concerns PJM's Regional Transmission Expansion Plan (RTEP) reforms which PJM is already pursuing. The remaining parts of the proposal are little different from the current capacity construct and do not address its limitations. FirstEnergy Service Company ("FirstEnergy") provided a "broad outline" of its Reliability Framework, which it offered as alternative to PJM's RPM Proposal,²³⁷ and which would, among other things, provide for a long-term expansion of the existing PJM RTEP Process in which

235. The Consumers Coalition includes Pennsylvania Office of Consumer Advocate, Maryland Office of People's Counsel, District of Columbia Office of People's Counsel, Ohio Office of Consumers' Counsel, Old Dominion Electric Cooperative, North Carolina Electric Membership Corporation, Allegheny Electric Cooperative, Inc., Borough of Chambersburg, Pennsylvania, Illinois Citizens Utility Board, Southern Maryland Electric Cooperative, Virginia Division of Consumer Counsel, and Indiana Office of Utility Consumers Counselor.

236. Answer of PJM Interconnection, L.L.C. to Comments and Protests, FERC Docket Nos. ER05-1410-000, EL05-148-000 (Nov. 8, 2005).

237. Motion to Intervene, Comments and Protest of First Energy Service Company, FERC Docket Nos. ER05-1410-000, EL05-148-000 (Oct. 19, 2005).

PJM, in collaboration with affected States, would develop a plan that proposes the optimal mix and locational character of existing resources and new investments to ensure capacity requirements, including transmission projects and baseload, intermediate, and peaking generation. PPL proposes an alternative that it asserts has much in common with RPM, including locational valuation of capacity, and an auction incorporating a downward-sloping demand curve. In PJM's view,²³⁸ PPL's proposal and RPM differ mainly in that under the former the auction would be held no earlier than one year prior to the delivery year.

4. CAISO

According to the California Energy Commission (CEC), California over the next several years will face "significant challenges in ensuring adequate electricity supplies to keep California's lights on during critical peak demand periods."²³⁹ In its 2004 Integrated Energy Policy Report Update (2004 Energy Report), the CEC stated that California must address its long-term electricity needs by bringing new generation online. The lack of available long-term power contracts has stalled the construction of more than 7,000 MW of plants already permitted and has sharply curtailed the amount of capacity seeking new permits. According to the Commission, "if unforeseen events cause electricity demand to rise sharply in the next few years, utilities may find themselves forced once again to enter into high-priced contracts that result in higher electricity prices for consumers."²⁴⁰ The CEC warned that utilities need to invest now for the long-term to continue to avoid the mistakes made during the 2000–2001 energy crisis that Californians are still paying for today.²⁴¹

The CEC concluded that the development of capacity markets could effectively provide a price signal of the value of capacity to power plant owners and developers.²⁴² The CEC supports the CPUC's proposal to explore developing a capacity market and local deliverability requirements in California.²⁴³ In its 2004 Energy Report, the CEC recommended the following broad policy principles that the CPUC and stakeholders could follow in developing a capacity market:

- Capacity markets should make compliance with resource adequacy requirements easier and less expensive, while supporting applicable local deliverability requirements.
- Initial steps should be targeted to meeting near-term capacity requirements. All qualifying capacity should be eligible to participate in a capacity market. The Energy Commission staff white paper suggested that some aging plants could compete quite effectively in such a market.
- Tradeable capacity obligations should use standardized contractual terms and conditions, and should include provisions to ensure that they are actually available to the system operators as needed.
- Establishing standardized contract terms and conditions, including an availability commitment provision that can be traded in bilateral contracts and can be the foundation for a broader capacity market that will grow

238. *Id.* at 60–61.

239. CAL. ENERGY COMM'N, 2004 ENERGY REPORT xiii (2004) [hereinafter 2004 ENERGY REPORT].

240. CAL. ENERGY COMM'N, 2005 INTEGRATED ENERGY POLICY REPORT (2005).

241. *Id.*

242. 2004 ENERGY REPORT, *supra* note 240, at 14.

243. *Id.* at 14–15.

over time.²⁴⁴

The CPUC and the CEC are progressing toward establishing capacity obligations for resource adequacy.

On August 25, 2005, the Energy Division of the CPUC issued a white paper on capacity markets.²⁴⁵ The white paper states that there are two demand side structural problems that prevent the existing market from inducing an efficient level of investment in generation: lack of demand response to real time prices, and the free rider problem created by the ISO's inability to shut down service to specific customers. It continues that the damaging side effects of structural problems are the increase of market power and investor risk, and a break in the link between fixed cost recovery and the desired level of installed capacity. The white paper further observes that market power pressures regulators to mitigate spot prices and that because the structural market imperfections and adverse impacts cannot be fixed within a reasonable time frame, the regulator must step in with resource adequacy programs to induce adequate investment in production capacity.

The white paper describes how a well-defined capacity market compensates for energy market imperfections by stabilizing and guiding the market to provide the target level of generation adequacy at reasonable cost; efficiently restoring the revenues missing from the capped spot energy market; reducing both investor risk and market power; ensuring against double payment in the energy and capacity markets; ensuring that installed generation is available when it is needed; providing an effective means for the Commission to monitor and enforce compliance with its resource adequacy requirements; addressing free rider concerns associated with the implementation of retail choice; and working closely with the CAISO's locational spot energy market to ensure that generation locates where it is needed, and not in areas that are inaccessible to load.

The recommendations of the white paper were as follows:

1. Adopt a short-run capacity market approach with a downward sloping capacity-demand curve for the CAISO.
2. Further investigate alternative availability metrics (e.g. UCAP v. ISO-NE's proposed metric based on performance during shortage conditions) and ensure development of an availability metric that is applicable to hydro, wind, thermal and other generation technologies, and to appropriate demand response products.
3. Consider subtraction of peak energy rents from the capacity payment.
4. Adopt reasonable locational installed capacity requirements with locally varying demand curves, although the white paper noted that reflecting locational capacity presents the following design problems:
 - a. Specification of zones.
 - b. Specification of transmission limits on capacity flows.
 - c. Specification of rights to capacity transmission, if any.
 - d. Specification of zonal adequacy requirements.

244. 2004 ENERGY REPORT, *supra* note 240, at 15.

245. SEAN GALLAGHER, CAL. PUB. UTILITIES COMM'N, CAPACITY MARKETS WHITE PAPER (2005), available at http://www.cpuc.ca.gov/word_pdf/REPORT/48884.pdf.

- e. Specification of a price calculation method.
5. Consider protecting against capacity exports during times of tight supply through the use of capacity prices that fluctuate seasonally.
6. Investigate the dependability of capacity import contracts during times of high West-wide load.
7. Make the fixed-cost recovery curve explicit.
8. Strive for regulatory credibility.

The white paper examined several potential limitations of a capacity market: For example, will a central spot capacity market interfere with bilateral trading? Does a short-term capacity market alone provide an adequate foundation for investment? The white paper also reviewed ICAP demand curve developments in New York, PJM, and New England, and noted that the recent innovation in capacity market design is the use of a demand curve with a non-vertical slope.

The CAISO has expressed support for “the creation of some form of capacity market.”²⁴⁶ While the CAISO has commented that details concerning the appropriate structure of such market remain under evaluation, “the CAISO believes that an essential attribute of this market is the trading of a physical and verifiable capacity product.”²⁴⁷

According to CAISO, “[t]his requires a transition from reliance on firm energy products to a capacity product to satisfy [Resource Adequacy] obligations. Other RTO capacity markets transact in a single standard ‘all hours’ capacity product.”²⁴⁸ Accordingly, to the extent that the Commission would seek to build upon the experience of other regions in developing a centralized capacity market, the CAISO prefers a “Top-Down” approach to resource adequacy that provides advantages as a transition mechanism, rather than “following an original and untested course.”²⁴⁹

5. MISO

An important development in the MISO’s approach to ensuring resource adequacy was described in MISO’s October 19, 2005 comments on PJM’s RPM filing,²⁵⁰ where MISO stated:

In addition to the resource adequacy proposals mentioned above, the Midwest ISO is currently working with its stakeholders and state regulators on the development of what has been described as an “energy-only” market construct for resource adequacy. This energy-only market construct may be implemented in lieu of an

246. CAISO, CAISO COMMENTS ON TOP-DOWN VS. BOTTOM-UP APPROACH FOLLOWING APRIL 29, 2005 RESOURCE ADEQUACY WORKSHOP (2005), available at <http://www.caiso.com/docs/2005/05/11/20050511080737495.pdf> [hereinafter CAISO COMMENTS ON TOP-DOWN VS. BOTTOM-UP].

247. *Id.*

248. CAISO COMMENTS ON TOP-DOWN VS. BOTTOM-UP, *supra* note 247.

249. *Id.* at 3. “[T]he principle difference between the ‘pure’ [Top-Down] and the [Bottom-Up] proposals is the sources for establishing the parameters of the resource’s obligation. In the [Top-Down approach], the resource is obligated . . . to offer for all hours it is physically capable of running consistent with environmental or other regulatory limitations. In contrast, the [Bottom-Up] resources are limited . . . also by contractual offer periods . . .” CAISO COMMENTS ON TOP-DOWN VS. BOTTOM-UP, *supra* note 247, at 3.

250. Motion to Intervene and Comments of the Midwest Independent Transmission System Operator, Inc., FERC Docket Nos. ER05-1410-000, EL05-148-000 (Oct. 19, 2005) [hereinafter Motion to Intervene and MISO Comments].

explicit capacity requirement and corresponding capacity market.²⁵¹

MISO went on to state,

A primary motive in considering this energy-only approach by the Midwest ISO is the concern widely held by stakeholders in the Midwest and by some market design experts that the complexity and administrative involvement inherent in developing any type of capacity construct might place the Midwest region on a “slippery slope,” taking it further away from the goal of using market-based means to pursue resource adequacy and a workably competitive market structure that will drive investment in generation and transmission infrastructure.²⁵²

The paper referred to by MISO concerning an “energy only” market for resource adequacy²⁵³ is discussed below.

a. MISO-Hogan Energy Only Market

In its filed comments on PJM’s RPM filing, MISO states that it:

appreciates PJM’s [attempt] to present a proposal to address the myriad of investment and operational incentive problems identified in its filing and [that MISO] is not commenting, at this time, as to whether RPM is an appropriate solution to these problems for the PJM region. Instead, [MISO’s] focus . . . is on the potential effect [that] the RPM proposal may have on the choices [that MISO], its members and affected states may have with respect to a resource adequacy mechanism for the [MISO] footprint if the Commission were to approve the RPM proposal and its potential implementation throughout the PJM region.²⁵⁴

In particular, MISO is concerned whether approval of PJM’s proposal would make it difficult to implement such alternatives as an “energy only” market for resource adequacy. How such a market might work has been spelled out in some detail in a paper written by Dr. William W. Hogan.²⁵⁵

In Dr. Hogan’s view, the revenue, which generators are not receiving because of price caps and mitigation, “reflects a view that market design imperfections suppress electricity prices in spot markets” and “produces inadequate incentives to invest in infrastructure resources such as generation capacity and its substitutes.”²⁵⁶ The approach he discusses “to address the imperfections in the market design, provide the missing incentives, and eliminate the missing money” is an “energy only” market, which he believes “would not remove the need for regulatory interventions, but it would substantially change the character of those interventions.”²⁵⁷

Dr. Hogan explains that his version of an “energy only” market would not include only:

spot deliveries of electric energy with a complete absence of administrative features in the market. Since the technology of electricity systems does not yet allow for operations dictated solely by market transactions with simple well-defined property rights, the system [would] require[] some rules to deal with the complex interactions in the network[,] [such as an] array of ancillary services and associated

251. *Id.* at 8–9 (footnote omitted).

252. Motion to Intervene and MISO Comments, *supra* note 251, at 9–10.

253. William W. Hogan, On An “Energy Only” Electricity Market Design for Resource Adequacy (Sept. 2005) (unpublished manuscript), available at http://www.ksg.harvard.edu/hepg/Papers/Hogan_Energy_Only_-92305.pdf.

254. Motion to Intervene and MISO Comments, *supra* note 251, at 3–4.

255. Hogan, *supra* note 254.

256. *Id.* at 34.

257. Hogan, *supra* note 254, at 34.

administrative rules for such services.²⁵⁸

As an example, he states that “the existing technology for electricity requires that system security be met by providing operating reserves in generation in order to meet the possible contingencies.”²⁵⁹

Dr. Hogan further explains that “the average opportunity cost of the involuntary curtailment” in an energy only market “would be the average ‘value of the lost load’ (VOLL) defined by the implicit demand curve, which represents the correct estimate of the cost of curtailment given the limits on control of inflexible load.”²⁶⁰ He further states that “[a]bsent some means of credible declaration by the customers, this implicit demand curve would be estimated by regulators or by the system operator. Hence, there would be an administrative determination of what should serve as the average VOLL.”²⁶¹

At first glance, it would appear that an administrative determination of VOLL could be as controversial and speculative as any issue in the various litigated resource adequacy proceedings to date. But it remains to be seen whether this is proven correct by actual experience.

With regard to market power, Dr. Hogan states that concerns regarding the exercise of “market power would remain in an energy-only market.”²⁶² In fact, “[w]ith no limit on energy and operating reserve prices other than the average VOLL, there would be even greater fear about potential incentives to exercise market power.”²⁶³ However, he believes that:

[t]he ability of generators to enter the market with new capacity supported by voluntary contracts with consumers should make the long-term energy market workably competitive. Without artificial barriers to entry, no special policy would be required to address market power in forward contracting with a sufficiently long horizon that allows for entry.²⁶⁴

Dr. Hogan then discusses “the short-term spot market [where], especially in the presence of transmission congestion that created load pockets . . . generators might have substantial market power and [may] be able to raise prices above competitive levels.”²⁶⁵ Dr. Hogan states that

[t]he market design could include administrative intervention when and where there was a serious possibility of an exercise of . . . market power through physical or economic withholding[, but that] the interventions would be structured to emulate the results of competition to the greatest degree possible. These interventions would be in the form of offer caps and offer requirements for generators, with appropriate exemptions for all generators who are not in a position to exercise market power or who enter a market with new facilities.²⁶⁶

“Deciding on the level of the appropriate offer caps would be contentious,” he concedes, “but the focus would be on preventing withholding and not on keeping prices low.”²⁶⁷

258. *Id.* at 9.

259. Hogan, *supra* note 254, at 9.

260. *Id.* at 10.

261. Hogan, *supra* note 254, at 11.

262. *Id.* at 25.

263. Hogan, *supra* note 254, at 25.

264. *Id.* at 25.

265. Hogan, *supra* note 254, at 25.

266. *Id.* at 25.

267. Hogan, *supra* note 254, at 25.

Dr. Hogan also discusses the concept of a "Mandatory Load Hedge," which "would be a regulatory intervention to address the concern that there would be inadequate forward contracting."²⁶⁸ Finally, Dr. Hogan discusses the transition from ICAP resource adequacy mechanisms to an energy only market. He maintains that "there appears to be nothing that dictates that an improved spot market design is mutually exclusive [with] an ICAP approach."²⁶⁹ Dr. Hogan supports this claim with a short discussion of the mechanisms used to coordinate energy and capacity markets, and ancillary services markets, if they create substantial revenue. Typically such mechanisms, such as ISO-NE's peak energy rent deduction proposal, subtract energy market revenues from money that would be distributed through the capacity market. Thus, if the energy market can be improved so that price caps are no longer binding, more revenues should be available through the energy market which would leave fewer revenues to be collected through the capacity market. And if the energy market can be totally perfected, theoretically there would be nothing to collect through the capacity market and that market could and would "wither away" to nothing.²⁷⁰

B. Generation Retirement and Reliability Must Run contracts

On May 6, 2004, the Commission issued an order establishing a Reliability Compensation Issues policy and ruling on a filing made by PJM Interconnection, LLC (PJM Order). The PJM order was prompted by "a complaint against PJM [alleging] that the offer price caps on certain . . . generat[ing] facilities in PJM operating areas that were subject to chronic transmission constraints were not just and reasonable."²⁷¹ The FERC noted that "PJM itself had recognized that its current provisions may not have been the most appropriate mechanism for providing recovery to Reliability Must Run (RMR) units, particularly as they relate to scarcity pricing."²⁷² The Commission ordered PJM "to make a filing . . . either revising its tariff[,] or [justifying] its existing provisions."²⁷³

In the PJM Order the Commission addressed the issue of ensuring "appropriate compensation to generators [that are] needed for reliability but [that are] subject to market power mitigation."²⁷⁴ The Commission explained that Reliability Compensation Issues (RCIs) arise because "[market] power mitigation (which impacts revenue received by units needed to ensure reliability) can conflict with the longer term goal of attracting and retaining necessary infrastructure to assure long-term reliability in such markets"²⁷⁵ It identified Short-term RCIs as relating:

to the appropriate compensation for units that are needed for reliability and are subject to mitigation[,] with the result that such units are receiving non-compensatory revenue impacting their ability to provide service. Long-term [RCIs] relate principally to local capacity shortages identified in the organized market's reliability-based planning process resulting from the reasonably expected retirement of units or the need for new infrastructure that is not anticipated to be installed.²⁷⁶

268. *Id.* at 27.

269. Hogan, *supra* note 254, at 33.

270. *Id.* at 33.

271. *PJM Interconnection, LLC*, 107 F.E.R.C. ¶ 61,112 at P 2 (2004).

272. *Id.* at P 5.

273. 107 F.E.R.C. ¶ 61,112 at P 5.

274. *Id.* at P 14.

275. 107 F.E.R.C. ¶ 61,112, at P 16.

276. *Id.*

The Commission concluded that rather than apply a standard regulatory response, it would “employ an overarching analytical approach” to addressing RCIs.²⁷⁷ The process begins with questioning whether an organized market exhibits Short- or Long-term RCIs.²⁷⁸ If material RCIs are present in the market, “the next step is to evaluate whether market design improvements can be implemented that [would] resolve those issues.”²⁷⁹ However, if material RCIs are not present, then more “targeted approaches (such as unit specific contracts or compensation schemes) may be appropriate.”²⁸⁰ The Commission explained how RCIs occur in the market:

Reliability Compensation Issues can easily occur when the market design elements are not well coordinated and the value of services that provide local reliability is not reflected in the market. The value of such service should be apparent to both buyers and sellers. Market design features that can work as solutions to these problems include: locational changes such as locational installed capacity, locational operating reserves, locational pricing for energy in times of local operating reserves scarcity; higher bid caps or relaxed mitigation for otherwise mitigated units needed for reliability (increased reference prices; proxy unit based approaches; increased offer caps in unit-based cost capping regimes); or other approaches that are designed to solve the Reliability Compensation Issues while also taking into account appropriate protections against the unwarranted exercise of market power. Further, basic market design should be considered to prevent the existence of these problems.²⁸¹

The Commission concluded “that the use of market design improved features is the preferred choice for solving material Reliability Compensation Issues.”²⁸²

The Commission concluded in the PJM Order that PJM exhibited few material Short- or Long-term RCIs, stating “[i]n large part, this is because elements of PJM’s market design are designed to ensure that there is construction of adequate transmission infrastructure.”²⁸³ The Commission accepted as modified PJM’s proposed revisions relating to the suspension of offer caps, but rejected certain other provisions. The Commission directed PJM to: 1) “develop a policy on retirement of generating units and file revised rules on retirement of generating units[,]” 2) investigate and report on “the use of pricing that recognizes operating reserve deficiencies in its market design[,]” and 3) “revise its tariff to provide the right to frequently mitigated units needed for reliability . . . to receive higher offer caps or alternative compensation alternatives.”²⁸⁴ The FERC on January 25, 2005,²⁸⁵ and July 5, 2005,²⁸⁶ resolved a number of the outstanding concerns but established a hearing to consider issues related to market power and scarcity pricing within PJM.

277. *PJM Interconnection, L.L.C.*, 107 F.E.R.C. ¶ 61,112 at P 15 (2004).

278. *Id.* at 16.

279. 107 F.E.R.C. ¶ 61,112 at P 17.

280. *Id.*

281. 107 F.E.R.C. ¶ 61,112 at P 19.

282. *Id.* at P 20.

283. *PJM Interconnection, L.L.C.*, 107 F.E.R.C. ¶ 61,112 at P 23 (2004). However the Commission stated that there was a need in PJM for certain changes to the market design to better reflect scarcity conditions in market prices, and certain changes to the mitigation rules. *Id.*

284. 107 F.E.R.C. ¶ 61,112 at P 39. By “frequently mitigated units” the Commission meant units that are offer capped for 80% or more of their run hours, are needed for reliability, and are not recovering sufficient revenues to cover their costs.

285. *PJM Interconnection, L.L.C.*, 110 F.E.R.C. ¶ 61,053 (2005).

286. *PJM Interconnection, L.L.C.*, 112 F.E.R.C. ¶ 61,031 (2005).

The Commission has found that RCIs existed in other regions, such as New England and California. In New England, the FERC concluded that suppliers in Designated Congestion Areas (DCAs) including Southwest Connecticut were not given "an adequate opportunity to recover their costs[,] and that a location-specific capacity requirement must be [put] in place."²⁸⁷ In California, the Independent Energy Producers Association (IEPA) filed a complaint against CAISO, seeking an order from the Commission directing the CAISO to replace the existing Must-Offer Obligation with an interim set of Reliability Capacity Services Tariff provisions.²⁸⁸

1. Proliferation of RMR Agreements

a. California ISO

In California, RMR contracts are awarded based on annual studies conducted by the CAISO to identify "power plants needed to meet reliability" requirements.²⁸⁹ According to the California Energy Commission (CEC), up to 9,000 MW of aging power plants are at medium to high risk for retirement by 2008.²⁹⁰ The 2005 Integrated Energy Policy Report (2005 Energy Report) stated that "[i]n San Francisco, additional transmission capacity is urgently needed to reduce [RMR] costs and allow shutdown of the city's aging power plants."²⁹¹ In addition, "the majority of load [in San Diego] is served by heavily congested transmission lines [that] cannot . . . meet the region's reliability needs by 2010."²⁹² "Two natural gas-fired combined-cycle power plants are under construction in the San Diego area[,] which together will "add more than 1,000 MW of capacity [and] are scheduled to be online in 2006 and 2008."²⁹³

According to the CEC, RMR contracts were originally "intended to ensure local reliability, but have increasingly been used, . . . along with denial of must-offer waivers,²⁹⁴ for zonal reliability, *i.e.*, to mitigate congestion on the bulk transmission system."²⁹⁵ "[T]he CAISO has submitted tariff changes to [the] FERC that would formalize this role" ²⁹⁶ CEC reports that the amount of capacity under RMR contract might increase to serve the function of zonal reliability. The CEC in its 2005 Energy Report stated:

Both [the] FERC and the CPUC have strongly encouraged utilities to pursue alternatives to the expensive, inflexible RMR contracts that were developed eight years ago as temporary local reliability measures. The continuing central role of these contracts in reliability planning brings the adequacy of the current grid

287. *Devon Power LLC*, 103 F.E.R.C. ¶ 61,082 at P 31 (2003). See also *Devon Power LLC*, 107 F.E.R.C. ¶ 61,240 at P 30 (2004).

288. Complaint of the Independent Energy Producers Association to Implement an Interim Reliability Capacity Services Tariff, FERC Docket No. EL05-146-000 (Aug. 26, 2005) [hereinafter IEPA Complaint].

289. CAL. ENERGY COMM'N, 2004 INTEGRATED ENERGY POLICY REPORT UPDATE 7 (2004).

290. *Id.*

291. CAL. ENERGY COMM'N, 2005 INTEGRATED ENERGY POLICY REPORT (2005) [hereinafter 2005 ENERGY REPORT].

292. *Id.* at 45-46.

293. 2005 ENERGY REPORT, *supra* note 292, at 45.

294. A must-offer waiver is an agreement between the CAISO and a generator that the latter does not have to offer energy or capacity into a CAISO market for some specified period. See CAL. ENERGY COMM'N, RESOURCE, RELIABILITY AND ENVIRONMENTAL CONCERNS OF AGING POWER PLANT OPERATIONS AND RETIREMENTS (Aug. 2004) [hereinafter STAFF WHITE PAPER].

295. *Id.* at 55.

296. STAFF WHITE PAPER, *supra* note 295, at 55.

expansion process into sharp question. Despite significant additions to the transmission system over the last several years, California is still experiencing congestion and must rely upon costly RMR contracts for the foreseeable future.²⁹⁷

Under certain circumstances, in addition to calling upon RMR units the CAISO must call upon certain aging units under its must-offer requirement.²⁹⁸ The CAISO's "Must-Offer Obligation" is a requirement imposed by the FERC in 2001 upon generators to offer energy or capacity into a day-ahead or real-time market.²⁹⁹ The Commission required generators with Participating Generator Agreements to offer the CAISO all of their capacity in real time during all hours if it is available and not already scheduled to run through bilateral agreements.³⁰⁰ According to the Commission, the basis for the requirement was that "under competitive conditions, a generator that has available energy in real time should be willing to sell that energy at a price that covers its marginal costs, since it has no alternative purchaser at that time."³⁰¹ However, the must-offer obligation is currently being challenged before the FERC.

On August 26, 2005, the Independent Energy Producers Association (IEPA) filed a complaint at the Commission arguing that the Must-Offer Obligation does not fairly compensate generators for their capacity.³⁰² According to IEPA, the Must-Offer Obligation also creates a "perverse incentive for load-serving entities to forego forward contracting opportunities" and artificially suppresses California Energy prices, providing inadequate price signals for new investment in generation and transmission.³⁰³ It sought to replace the existing Must-Offer Obligation with an interim set of Reliability Capacity Services Tariff provisions.³⁰⁴ In its answer to IEPA's complaint, the CAISO acknowledged that the region suffers from Long-term RCIs. The CAISO responded:

The ISO acknowledges that the circumstances in the larger California electricity market are such that both existing generating resources and new resource developers are challenged to secure stable opportunities to recover a return both on and of their investments. The ISO also recognizes that its current market structure for addressing reliability concerns, through a combination of Reliability Must-Run Generation, real-time Intra-Zonal Congestion management protocols, and the Must-Offer Obligation, fails to induce appropriate investment in the infrastructure necessary to ensure long-term service reliability to California consumers, *i.e.*, it raises long-term reliability compensation issues, as those issues are discussed in *PJM Interconnection, LLC*, 107 FERC ¶ 61,112 (2004).³⁰⁵

On November 8–9, 2005, the FERC convened a technical conference to address the continuation of the CAISO's existing Must-Offer Obligation, details of any alternatives (such as the Reliability Capacity Service Tariff proposed by IEPA), and related implementation issues.³⁰⁶ The CAISO has stated that it is pursuing an approach to resolving RCIs that adopts market design solutions consistent with the Commission's PJM Order, such as its Market Redesign and

297. 2005 ENERGY REPORT, *supra* note 292, at 92.

298. STAFF WHITE PAPER, *supra* note 295, at 28.

299. *San Diego Gas & Elec. Co.*, 95 F.E.R.C. ¶ 61,115 (2001).

300. *Id.*

301. 95 F.E.R.C. ¶ 61,115.

302. IEPA Complaint, *supra* note 289, at 2.

303. *Id.*

304. IEPA Complaint, *supra* note 289, at 1.

305. Answer of the California Independent System Operator Corporation to the Complaint of the Independent Energy Producers Associations, FERC Docket No. EL05-146-000 (Oct. 3, 2005).

306. Notice of Technical Conference, FERC Docket No. EL05-146-000 (Oct. 25, 2005).

Technology Upgrade (MRTU), which the CAISO is pursuing in concert with the CPUC's Resource Adequacy Program. Pursuant to joint motions of the CAISO and IEPA, the proceeding at the FERC has been deferred pending the outcome of settlement discussions. The CPUC's Resource Adequacy program is discussed in further detail below.

b. ISO New England Inc.

There are many areas in New England that are import-constrained, and where ISO-NE and NEPOOL have stated that it was necessary to designate units as RMR units and to negotiate separate RMR agreements with generators. Most of the RMR units in New England are located in import constrained areas, such as Southwest Connecticut and Boston. ISO-NE has determined in a reliability assessment for Connecticut that "absent any transmission improvements or new resources, largely all of the existing resources in Connecticut are needed for reliability."³⁰⁷

RMR contracts, which compensate a unit for its fixed costs, are available to generation units that are not able to operate profitably. According to FERC's 2004 State of the Markets Report, in 2004 New England load-serving entities (LSEs) paid \$165 million to cover the fixed costs of generators under RMR contracts. These were out-of-market payments to generators, which are not reflected in market prices.³⁰⁸ The FERC noted that:

every new RMR contract . . . lowers the marginal unit in the bid stack and further reduces prices that occur in the market. In 2004, six new RMR contracts became effective to secure almost 1,437 MW from ISO-NE generators for an annual fixed cost of \$98.9 million. Another \$66.4 million in RMR contracts became effective in January 2005. The ISO estimates that total annual fixed-cost payments to generators in 2005 for all RMR contracts will be about \$345.1 million for 4,394 MW[, not including] 1,194 MW awaiting FERC approval.³⁰⁹

2. Gap RFPs

On December 1, 2003, ISO-NE issued a request for proposals (RFP) for Southwest Connecticut in which it is sought approximately 300 MW of quick-start capacity through generation and Demand Response Resources. In a subsequent filing on proposed changes to Market Rule 1, the NEPOOL Participants Committee stated that there were concerns with reliability in Southwest Connecticut that were expected to continue until upgrades to the transmission system are made in that region.³¹⁰ These reliability concerns had prompted ISO-NE to issue "an RFP in 2002 for load response or supplemental resources that could be relied upon until the longer term transmission solutions

307. ISO-NE stated in a letter dated February 26, 2003, that "the ISO-NE . . . has conducted a reliability assessment for Connecticut for the years 2003 and 2006 and has determined that, absent any transmission improvements or new resources, largely all of the existing resources in Connecticut are needed for reliability." *Devon Power LLC*, 103 F.E.R.C. ¶ 61,082 at P 27 (2003).

308. FED. ENERGY REGULATORY COMM'N, 2004 STATE OF THE MARKETS REPORT 88 (June 2005) [hereinafter 2004 MARKETS REPORT].

309. *Id.* at 88. For a summary of annualized fixed costs under RMR contracts in New England, see ISO NEW ENGLAND INC., RELIABILITY AGREEMENTS—ANNUAL FIXED COSTS SUMMARY (Oct. 7, 2005), available at http://www.iso-ne.com/genrtion_resrcs/reports/rmr/rmr_agreements_summary_with_fixed_costs.xls.

310. Letter from David T. Doot, New England Power Pool, to the Honorable Magalie Roman Salas, Sec'y, Fed. Energy Regulatory Comm'n (Dec. 23, 2003) (transmittal letter regarding revisions to NEPOOL Market Rule 1 (Gap RFPs)) [hereinafter Gap RFPs].

were implemented.”³¹¹ Based on its updated reliability studies, ISO-NE concluded that reliability concerns in Southwest Connecticut must also be addressed for the 2004 summer.

In connection with considering how to address the reliability concerns in Southwest Connecticut, NEPOOL and ISO-NE sought to adopt general rules that would apply whenever RFPs to address near-term and medium-term reliability concerns are needed while long-term solutions are being implemented. These RFPs are referred to as “Gap RFPs” because they address the gap between reliability needs and the market or regulated solutions addressing those needs.³¹²

On December 23, 2003, the NEPOOL Participants Committee filed changes to NEPOOL Market Rule 1. They “would apply whenever ISO-NE determines [that] RFPs to address near-term reliability concerns [are needed] while long-term solutions are being implemented.”³¹³ The Commission accepted the changes to Market Rule 1, subject to the condition that ISO-NE must file for the Commission’s approval of all future RFPs before they are issued.³¹⁴

ISO-NE’s LICAP proposal, introduced in *Devon Power LLC*,³¹⁵ is intended to improve market-based indicators for generation addition and retirement by appropriately valuing generation based on location, thus remedying local reliability issues and removing the need for RMR contracts.³¹⁶ “Those values will allow generators to receive more appropriate, market-driven prices than they receive under the current market rules, and out-of-market contracts will no longer be required. For this reason, the RMR Agreements the Commission is addressing in this interim period expire when the LICAP market begins.”³¹⁷

The LICAP proposal, which initially established separate ICAP requirements in four regions including a single Connecticut region, was revised to create a separate, import-constrained Southwest Connecticut ICAP region.³¹⁸ The Commission’s purpose for creating a separate ICAP region for Southwest Connecticut was “to ensure that the price of capacity in that area [appropriately] reflects its actual need for investment and demand response”³¹⁹

3. Commission Response to RMR Contract Proliferation

The Commission has stated that “extensive use of RMR contracts undermines effective market performance.”³²⁰ In its April 25, 2003 order addressing requests for RMR treatment for certain generators in Connecticut and Southwest Connecticut, the Commission explained:

RMR contracts suppress market-clearing prices, increase uplift payments, and make it difficult for new generators to profitably enter the market. That is because under

311. *Id.*

312. Gap RFPs, *supra* note 311, at 2.

313. *New England Power Pool*, 106 F.E.R.C. ¶ 61,190 (2004), *order on reh’g*, 107 F.E.R.C. ¶ 61,208 (2004), *order denying reh’g*, 108 F.E.R.C. ¶ 61,306 (2004).

314. *New England Power Pool*, 106 F.E.R.C. ¶ 61,190 (2004), *order on reh’g*, 107 F.E.R.C. ¶ 61,208 (2004), *order denying reh’g*, 108 F.E.R.C. ¶ 61,306 (2004). Since ISO-NE had already issued the Southwest Connecticut RFP and the contracts would be for reliability needs that summer, the Commission allowed that process to go forward. 106 F.E.R.C. ¶ 61,190 at P 10.

315. *See Devon Power LLC*, 111 F.E.R.C. ¶ 63,063 at PP 2–36 (2005).

316. 2004 MARKETS REPORT, *supra* note 309, at 88.

317. *PSEG Power Conn., LLC*, 110 F.E.R.C. ¶ 61,020 at P 20 (2005).

318. *Devon Power LLC*, 109 F.E.R.C. ¶ 61,156 at P 1 (2004).

319. *Id.* at P 25.

320. *Devon Power LLC*, 103 F.E.R.C. ¶ 61,082 at P 29 (2003).

current market rules, generators operating under a cost-of-service RMR contract must offer power under a Stipulated Bid Cost that includes stipulated marginal, start-up and no-load costs. The units are then entitled to a monthly fixed cost payment to the extent that revenues earned from the energy market, including any payments for start-up and no-load costs, do not recover allowable capacity costs and fixed O&M costs. As a result, expensive generators under RMR contracts receive greater revenues than new entrants, who would receive lower revenues from the suppressed spot market price.³²¹

Moreover, suppressed market clearing prices hinder the ability of other generators to earn competitive revenues in the market, and increase the likelihood that additional units will seek RMR treatment to remain profitable.

The Commission concluded "that RMR agreements should be a last resort and that the proliferation of these agreements is not in the best interest of the competitive market as they affect other suppliers participating in this market, especially those suppliers operating within the same DCA."³²² In a series of orders on several New England RMR agreements submitted for filing, the Commission "rejected the widespread use of RMR agreements as a default tool to provide cost recovery to generating facilities that must run to ensure reliability because the units' cost-of-service under such contracts are recovered through payments made outside of the market."³²³ These orders directed ISO-NE to establish Peaking Unit Safe Harbor (PUSH) bidding to provide those generators an opportunity to recover their costs through the market.³²⁴ Thus, concerning the requests for RMR treatment in New England, the Commission stated that "ISO-NE, rather than focusing on and using stand-alone RMR agreements, should incorporate the effect of those agreements into a market-type mechanism."³²⁵ It directed ISO-NE to develop a replacement for PUSH bidding by filing a mechanism that implements "location or deliverability requirements in the ICAP or resource adequacy market . . . so that capacity within DCAs may be appropriately compensated for reliability."³²⁶

4. Other Proposals Concerning RMR Contracts

On September 12, 2005, several Connecticut representatives³²⁷ filed a complaint at the Commission seeking to amend ISO-NE's Market Rule 1 with regard to the compensation of electric generation facilities in Connecticut.³²⁸ They "seek to amend Market Rule 1 . . . to ensure that all electric generation facilities that have been designated as an RMR Resource or are otherwise determined by ISO-NE as necessary for reliability in Connecticut must apply to ISO-NE for cost-of-service compensation."³²⁹

321. *Id.*

322. 103 F.E.R.C. ¶ 61,082 at P 31.

323. *Devon Power LLC*, 109 F.E.R.C. ¶ 61,156 at P 3 (2004). *See also Devon Power LLC*, 102 F.E.R.C. ¶ 61,314 (2003); *Devon Power LLC*, 103 F.E.R.C. ¶ 61,082 (2003); *PPL Wallingford Energy LLC*, 103 F.E.R.C. ¶ 61,185 (2003); *Devon Power Co.*, 104 F.E.R.C. ¶ 61,123; *PPL Wallingford Energy LLC*, 105 F.E.R.C. ¶ 61,324 (2003).

324. *Id.*

325. *Devon Power LLC*, 103 F.E.R.C. ¶ 61,082 at P 29 (2003).

326. *Id.* at P 37. *See also* 109 F.E.R.C. ¶ 61,156 at P 3.

327. Richard Blumenthal, Attorney General for the State of Connecticut (CTAG), the Connecticut Office of Consumer Counsel (CT OCC), the Connecticut Municipal Electric Energy Cooperative (CMEEC) and the Connecticut Industrial Energy Consumers (CIEC) (collectively, Connecticut representatives).

328. Complaint Requesting Fast Track Processing, FERC Docket No. EL05-150-000 (Sept. 12, 2005) [hereinafter CT Complaint].

329. *Id.* at 1-2.

The Connecticut representatives argued that the Commission's current regulatory policies in Connecticut violated "the Federal Power Act by ensuring that electric consumers in Connecticut are paying the higher of either cost of service or market-based rates for electricity[, resulting in] rates that are unjust and unreasonable."³³⁰ According to the Connecticut representatives, the Commission authorized every generator in Connecticut to receive revenue based on whatever the market will bear pursuant to their market-based rate authority or to opt out of the market based system and recover all of their fixed and variable costs and earn a return pursuant to RMR contracts.

In its answer, ISO-NE disagreed that the current rate structure provides compensation that is not just and reasonable.³³¹ According to ISO-NE, the Connecticut representatives sought to re-litigate the Commission's prior determinations in a series of orders that the current rate structure based on the locational marginal pricing (LMP) of Standard Market Design (SMD) in New England is just and reasonable.³³² ISO-NE pointed out that the Commission authorized the use of RMR agreements in the current LMP markets while a capacity market solution is being developed, finding that the use of RMR agreements would be just and reasonable in an LMP-based market until a market-based solution to the under-compensation issue is implemented to replace RMR contracts.

The Connecticut representatives requested that the Commission treat its complaint as an expedited fast track proceeding. The matter is currently pending before the Commission.

C. *Determination of Installed Capacity*³³³

Under its Markets and Services Tariff and section 11.4 of the New England Participants Agreement, ISO-NE must file with the Commission the IC Requirements for the Power Year.³³⁴ The IC Requirement, which is a projection of the minimum amount of capacity required to serve load reliably in the New England region, is used to determine the monthly Unforced Capacity (UCAP) requirements that each Market Participant must purchase.³³⁵ To meet their UCAP obligations, Market Participants must self-supply, purchase UCAP through bilateral transactions, or obtain capacity credits from tie-line benefits, or they must make up any deficiencies in the ISO-administered installed capacity market. ISO-NE calculates the IC Requirements to meet system design criteria with a Loss of Load Expectation of one day in ten years.

On March 21, 2005, as later supplemented on April 1, 2005, ISO-NE filed its IC Requirements for the 2005/2006 Power Year.³³⁶ Compared to the assumptions that were used in the development of the IC Requirements for Power Year 2004/2005, ISO-NE used 1800 MW rather than 2000 MW as the

330. CT Complaint, *supra* note 329, at 2.

331. Answer of ISO New England Inc. to Complaint Requesting Fast Track Processing of Richard Blumenthal, Attorney General for the State of Connecticut, FERC Docket No. EL05-150-000 (Oct. 20, 2005).

332. *Id.* at 3.

333. Prior to the establishment of ISO-NE as an RTO, the minimum amount of capacity required to serve load reliably in the New England region was referred to as Objective Capability or OC. However, since the establishment of ISO-NE as an RTO, this minimum amount of capacity is referred to as "Installed Capacity Requirements" in the relevant ISO-NE documents, including its tariff.

334. *ISO New England Inc.*, 111 F.E.R.C. ¶ 61,185 at P 2 (2005).

335. *Id.*

336. 111 F.E.R.C. ¶ 61,185 at P 3.

measure of tie benefits, and used the Equivalent Demand Forced Outage Rate (EFORD) generator availability metric, instead of the Equivalent Forced Outage Rate (EFOR) availability metric.³³⁷ In response to protests concerning the ISO's use of 1800 MW of tie benefits and its use of EFORD, The FERC on May 9, 2005 issued an order directing ISO-NE to include 2000 MW of tie benefits in the determination of the IC Requirements.³³⁸ The Commission denied the protests regarding EFORD, noting that it had approved the use of EFORD when it approved the Standard Market Design for New England.³³⁹ The Commission also noted that the IC Requirements are inputs to the LICAP determinations and that issues related to the LICAP determinations, and the rates applied to LICAP requirements should be addressed in that proceeding.³⁴⁰

The Commission on September 7, 2005 denied several requests for rehearing of its May 9, 2005 order.³⁴¹ On October 28, 2005, the Connecticut Department of Public Utility Control filed an appeal of the Commission's order denying rehearing in the United States Court of Appeals for the District of Columbia Circuit. At press time, that appeal was still pending review.

D. Ancillary Services

1. Ancillary Service Market Phase I and Phase II Filings

On April 7, 2005, ISO-NE and NEPOOL jointly filed a package of proposed market changes to effectuate Phase I of its Ancillary Services Market Project.³⁴² The proposed market changes would: (1) re-institute a Regulation market design that pays generators based on the amount of service provided; (2) provide generators greater flexibility to adjust their Supply Offers during the Re-Offer Period that occurs after the close of the Day-Ahead Energy Market; and (3) implement software changes that will allow a Dispatchable External Transaction purchase to be eligible to set the nodal energy clearing price when it is the marginal resource.³⁴³ The Commission on June 6, 2005 issued an order accepting the proposed tariff revisions for filing, effective October 1, 2005, and requiring further filings.³⁴⁴ Phase II of the ASM project includes market modifications that are under development and are the subject of ongoing

337. *Id.* "The EFORD is not to be confused with the Equivalent Forced Outage Rate (EFOR). EFOR is defined by the NERC GADS Data Reporting Instructions in Appendix F. This value may be calculated on any time period basis including hourly, daily, weekly, monthly, quarterly, and annually, as well as the time periods based on these individual time periods such as 12-month rolling averages, last 3 years, peak periods, etc. depending on the completeness of the reported event data." SOLOMON ASSOCS., EQUIVALENT DEMAND FORCED OUTAGE RATE: EFORD, available at <http://www.762nxi.com/EFORDDiscussion.asp> (last visited Feb. 26, 2006).

338. 111 F.E.R.C. ¶ 61,185 at PP 30-32.

339. See *New England Power Pool*, 100 F.E.R.C. ¶ 61,287 at PP 12, 96-98 (2002), *order on reh'g*, 103 F.E.R.C. ¶ 61,304 at P 77 n. 29 (2003).

340. *Id.*

341. *ISO New England, Inc.*, 112 F.E.R.C. ¶ 61,254 (2005). Requests for Rehearing or Clarification of the May 9, 2005 order were filed by the Connecticut Department of Public Utility Control, the Connecticut Office of Consumer Counsel, and Richard Blumenthal, Attorney General for the State of Connecticut; the Long Island Power Authority and its operating subsidiary LIPA; the New England Conference of Public Utilities Commissioners; and the New England Power Pool Participants Committee.

342. Letter from ISO New England Inc. and New England Power Pool, to the Honorable Magalie Roman Salas, Sec'y, Fed. Energy Regulatory Comm'n (Apr. 7, 2005) (transmittal letter regarding Ancillary Services Market Phase I, Docket No. ER05-795-000).

343. *Id.* at 1.

344. *ISO New England, Inc.*, 111 F.E.R.C. ¶ 61,364 (2005).

stakeholder processes.

2. Forward Reserves Markets

This section will focus on developments in two RTOs where significant changes in reserves markets are currently being developed or already have been proposed in a Commission filing: ISO-NE's Ancillary Services Market (ASM) Phase II Forward Reserves Proposal and PJM's Reliability Pricing Model (RPM) proposal.

a. ISO-NE's ASM Phase II Forward Reserves Market

i. Prior to ISO-NE's September 9, 2003 Filing

Prior to the September 9, 2003 filing of ISO-NE and NEPOOL to establish a forward reserve market, the market in New England did not contain a separate market for operating reserves. Rather, ISO-NE procured "operating reserves by determining which resources [were] needed based on the day-ahead market."³⁴⁵ ISO-NE used this determination to schedule resources, which included any required adjustment of the output of already scheduled and self-scheduled resources, and the determination of which off-line resources were needed.

Resources that provided operating reserves receive[d] revenues from producing energy, Operating Reserve Credits for on-line resources, and revenues from providing installed capacity (ICAP). Off-line reserves, however, [did] not receive revenues for providing operating reserves and only received energy payments when occasionally called on to produce. The only other current revenue stream for off-line units [was] through ICAP payments. Thus, there [was] no incentive to provide such resources.³⁴⁶

ii. Current Forward Reserve Market

To provide improved incentives for the provision of operating reserves, ISO-NE and NEPOOL in September, 2003 filed their Forward Reserve Market Filing, which proposed to add a new Section 9 to Market Rule 1. It was accepted by the Commission³⁴⁷ and became effective on January 1, 2004. As part of this reserve market, which is currently in operation in New England, ISO-NE established

a regional Operating Reserve Purchase requirement [which is satisfied] through a competitive auction. The auction acquires operating reserves via a call option, *i.e.*, a reservation payment, on the selected resources to be available when needed by ISO-NE during the service period. Resources selected from the auction process [are] obligated to bid into the energy market at or above a predetermined Strike Price. These Forward Reserve Resources [are] required to provide energy upon request within 10 minutes or 30 minutes depending on the type of reserve supplying, and, if selected, are eligible to set LMP The costs of operating reserves [are] allocated to participants based on Real-Time Load Obligations (RTLO) as defined in Market Rule 1.³⁴⁸

345. *New England Power Pool*, 105 F.E.R.C. ¶ 61,204 at P 2 (2003).

346. *Id.* "These payments are designed to make on-line resources whole when their energy payments are not sufficient to cover their running costs such as long minimum start, run, or downtime." 105 F.E.R.C. ¶ 61,204 at P 2.

347. *New England Power Pool*, 105 F.E.R.C. ¶ 61,204 (2003), *reh'g denied*, 108 F.E.R.C. ¶ 61,047 (2004).

348. 105 F.E.R.C. ¶ 61,204 at P 3 (footnotes omitted). "The Forward Reserve Strike Price, defined in

The Forward Reserve auctions [are] held 1 to 6 months before the service period. Resources must specify whether the offers are for off-line or on-line reserves, and [are] evaluated and selected by ISO[-NE] to minimize the total cost of Forward Reserves. That is, higher quality 10-minute reserves may be selected to meet the 30-minute requirements if economic. In this regard, bids for on-line resources are required to include start-up and no-load costs so that the total cost of these resources is included in the evaluation. In addition, Forward Reserve offers [are] capped at the ICAP offer or price cap applicable in accordance with Market Rule 1, and if selected, Forward Reserve resources are required to be listed as ICAP resources during the period they are selected to provide operating reserves. Should a Forward Reserve Resource fail to meet its 10-minute or 30-minute delivery requirement, it forgoes its Forward Reserve Market compensation and may be required to pay a penalty,³⁴⁹ which is the MW reserve shortfall multiplied by any positive difference between the day-ahead LMP and the Forward Reserve Strike Price.³⁵⁰

iii. Current Scarcity Pricing Provisions

In parallel with the Forward Reserve market, on May 15, 2003, ISO-NE filed Scarcity Pricing Provisions "intended to ensure that energy prices are set at efficient levels when the [New England] Control Area is short of Operating Reserves."³⁵¹ These provisions were accepted by a Commission order issued July 25, 2003.³⁵² ISO-NE proposed to replace these provisions when it developed fully co-optimized energy and reserve markets.³⁵³

One part of the Scarcity Pricing Proposal . . . reinstitute[d] certain [provisions] that were in effect in New England prior to the Summer of 2002, but that could not be carried over when ISO-NE implemented [SMD] on March 1, 2003, due to software limitations. These [provisions:] (1) ma[de] offers from the most expensive dispatchable external transaction purchase scheduled eligible to set the energy price during periods of reserve shortages; and (2) ma[de] resources providing operating reserves eligible for opportunity costs. The other part of the Scarcity Pricing Proposal sets the energy component of the LMP at \$1000/MWh in shortage conditions to assure that the price of energy properly reflects its value as either energy or Operating Reserves.³⁵⁴

The Scarcity Pricing Proposal applies only to real time dispatch and the real time market. ISO-NE declares:

a Reserve Shortage Condition when it (1) is experiencing, or must take action to avoid experiencing, a deficiency in total ten minute Operating Reserves, or (2) is experiencing a deficiency in total operating reserves that has lasted longer than a

Section 9.6.2 of the proposed rule as [the] heat rate multiplied by a fuel index, is designed to ensure that Forward Reserves will be dispatched for energy infrequently by using the expected operating profile of a peaking resource." *Id.* at P 2.

349. 105 F.E.R.C. ¶ 61,204 at P 4 (footnote inserted). "The penalty takes two forms. A failure to reserve penalty is incurred when a unit fails to offer the required MW above the strike price, and a failure to perform penalty is incurred when a resource that is called upon fails to start." *Id.* at P 4 n. 3.

350. 105 F.E.R.C. ¶ 61,204 at P 4.

351. *ISO New England, Inc.*, 104 F.E.R.C. ¶ 61,130 (2003).

352. *Id.*

353. "Under fully co-optimized energy and reserve markets, the ISO would consider jointly the generators that offer to supply energy and/or reserves in developing a schedule that minimizes the combined cost of providing energy and reserves." 104 F.E.R.C. ¶ 61,130 at P 10 n. 4. "[The ISO stated that] these markets might utilize a demand curve representing the value of reserves at different levels, allowing the markets to set prices efficiently to reflect different levels of scarcity during shortage conditions of different intensity." *Id.* at P 9.

354. 104 F.E.R.C. ¶ 61,130 at P 5. "The dispatch algorithm includes in the calculation of LMPs the effect of losses from the marginal resource to the reference node, and thus it is possible for the energy component (the LMP at the reference node) to exceed \$1,000." *Id.* at P 5.

four-hour period of time and has begun or is anticipating taking out-of-merit actions or engaging in emergency energy transactions to maintain or preserve Operating Reserves. The Reserve Shortage Condition [is] terminated when ISO-NE . . . determine[s] that system conditions have improved to the point where out-of-merit dispatch is no longer needed to maintain required operating reserves.³⁵⁵

ISO-NE notifies the market when Reserve Scarcity Conditions occur and it adjusts real time LMPs before they are published.

During reserve shortage conditions, if ISO-NE's actions have not restored operating reserves to required levels, the energy component of the affected nodal Real-Time prices [is] set to the higher of \$1000/MWh or the energy component of the nodal Real-Time price. Moreover, if ISO-NE calls a reserve shortage condition and a deficiency level is avoided by scheduling a dispatchable import, the energy component of LMP [is] set at the higher of its original value or the most expensive import required to eliminate the deficiency. If a resource is dispatched down to provide operating reserves, it [receives] an opportunity cost payment equal to the difference between the adjusted LMP and the resource's supply offer.³⁵⁶

If the market monitoring unit and independent market advisor determine that the shortage condition and subsequent prices result from one or more participants physically withholding, the real time prices are not to be adjusted. ISO-NE and its Independent Market Advisor asserted that ISO-NE's scarcity pricing proposal is fundamentally consistent with that of NYISO, and should not create or exacerbate any seams issues between the New England and New York markets.

iv. 2005 Ancillary Service Market: Enhancements – Phase I

On April 7, 2005, ISO-NE and NEPOOL filed at the FERC Phase I of its Ancillary Services Market Proposal, which consisted of market improvements that would: (1) re-institute a Regulation market design that pays generators based on the amount of service provided; (2) provide generators greater flexibility to adjust their Supply Offers during the Re-Offer Period that occurs after the close of the Day-Ahead Energy Market; and (3) implement software changes that would allow a Dispatchable External Transaction purchase to be eligible to set the nodal energy clearing price when it is the marginal resource. The Commission accepted this proposal on June 6, 2005.³⁵⁷

v. 2005 Ancillary Service Market: Enhancements – Phase II

On February 6, 2006, in Docket No. ER06-613-000, ISO-NE (joined by NEPOOL) filed its long anticipated revision to its Forward Reserve Market, with a proposed effective date of October 1, 2006.³⁵⁸ Among the major features of ISO-NE's proposal are:

Locational Component: "The most significant change included in ASM

355. 104 F.E.R.C. ¶ 61,130 at P 6. The Scarcity Pricing Proposal applies only when a reserve shortage condition is declared system-wide. However, it is possible that export-constrained areas may have adequate resources to meet energy and reserves needs. Accordingly, the Scarcity Pricing Proposal's energy pricing provisions do not apply to export constrained areas.

356. 104 F.E.R.C. ¶ 61,130 at P 7.

357. *New England Power Pool*, 105 F.E.R.C. ¶ 61,204 (2003), *reh'g denied*, 108 F.E.R.C. ¶ 61,047 (2004).

358. Letter from ISO New England and New England Power Pool, to the Honorable Magalie Roman Salas, Sec'y, Fed. Energy Regulatory Comm'n (Feb. 6, 2006) (transmittal letter regarding Ancillary Services Market Phase II, Docket No. ER06-613-000) [hereinafter Market Phase II Letter].

Phase II would add a locational component to the existing Forward Reserve Market.”³⁵⁹ “The location-specific requirements for the Operating Reserve products are represented by Reserve Zones” and,

[i]n general, these requirements reflect the need for a certain amount of resources capable of responding to a second contingency in thirty minutes to be included inside a local Reserve Zone based on factors such as the minimum capacity requirement for first contingency protection, available transfer capability and forecast load.³⁶⁰

“The ISO may propose to reconfigure Reserve Zones in the future based on changes to the grid, patterns of usage and changes in local contingency response requirements.”³⁶¹

Portfolio Management: “The upgraded Forward Reserve Market will also allow suppliers to manage their risks more efficiently by participating in the market on a portfolio basis.”³⁶² “The ability to trade obligations would reduce the risk premium associated with the performance penalties.”³⁶³

Co-optimized Energy and Reserve Prices: “ASM Phase II would also implement co-optimized pricing of energy and reserves in real time[,]” which “will result in a more efficient and less costly dispatch of generating units to satisfy the need for energy and reserves.”³⁶⁴ “When reserves cannot be maintained despite re-dispatch (i.e., there is a reserve shortage), the clearing prices will be derived from maximum price levels known as Reserve Constraint Penalty Factors (‘RCPFs’).”³⁶⁵ “To the extent that there is any excess Operating Reserve available, the excess capability may “cascade” down from the higher quality to the lower quality products” (i.e., Ten-Minute Spinning Reserve (TMSR) to Ten-Minute Non-Spinning Reserve (TMNSR) to Thirty-Minute Operating Reserve (TMOR)), and “Real-Time Reserve Clearing Prices may “cascade” up from TMOR to TMNSR to TMSR.”³⁶⁶ “In other words, units that respond faster may supply the slower-responding reserve products when they are priced lower.”³⁶⁷

Participation by Demand Resources: “ASM Phase II will include measures allowing the owners of demand resources to bid their resources (called ‘Asset Related Demand’) directly into the energy and reserve markets on an equal footing with generating resources.”³⁶⁸

Netting of Forward Reserve/ICAP Compensation: “[C]learing price of the monthly ICAP Supply Auction will be subtracted from the Forward Reserve Market clearing price during the settlement process. The result is that the clearing prices in the Forward Reserve Market will be incremental payments above the ICAP clearing prices.”³⁶⁹

359. *Id.* at 1, 7.

360. Market Phase II Letter, *supra* note 360, at 8.

361. *Id.* at 8 n.21.

362. Market Phase II Letter, *supra* note 360, at 2.

363. *Id.* at 8.

364. Market Phase II Letter, *supra* note 360, at 2.

365. *Id.* at 6.

366. Market Phase II Letter, *supra* note 360, at 13.

367. *Id.*

368. Market Phase II Letter, *supra* note 360, at 2, 9.

369. *Id.* at 10.

Forward Reserve Offer Cap: “The proposed Forward Reserve Offer Cap is \$14,000/megawatt-month. The offer cap amount is based on the estimated carrying cost of an aero-derivative combustion turbine that can respond to dispatch instructions within ten minutes[,]” which may be reevaluated in the future as necessary.³⁷⁰

Supplier Obligations: “The interim Forward Reserve Market requires that resources that are designated to provide reserves must submit energy offers in accordance with the Forward Reserve Threshold Price (or ‘strike price’), which is a minimum energy offer price[,]” and which “is derived from heat rate and fuel index parameters that are published several weeks prior to each Forward Reserve Auction.”³⁷¹ “The new Forward Reserve Market includes performance penalties that are similar to those contained in the existing market[:]” a Failure to Reserve Penalty and a Failure to Activate Penalty.³⁷² However, “[w]ith the ability of suppliers to manage a portfolio of resources in the new Forward Reserve Market, higher penalties are necessary to ensure performance.”³⁷³ In addition, as in the existing market, “as a condition of participation in the Forward Reserve Market, a resource designated to provide reserves must also be a fully-listed ICAP resource.”³⁷⁴

Cost Allocation for Forward and Real-Time Reserve Markets: ISO-NE is “proposing that Forward Reserve Market charges continue to be allocated based on Real-Time Load Obligation, but with the load ratio share calculated for each local area rather than the entire system.”³⁷⁵

The Relationship of the Forward and Real-Time Reserve Markets: “At this time, the ISO and stakeholders have not identified sufficient value in creating a multi-settlement market, such as by implementing a day-ahead market that would settle against the Real-Time Reserve Market.”³⁷⁶

Stakeholder Process and Additional Enhancements: ISO-NE states that two key issues prevented even broader support for ASM Phase II. The first issue, which resulted in most of the Publicly Owned sector opposing ASM Phase II related to the issue of self-supply of reserves. The second issue, which resulted in many suppliers abstaining in the ASM Phase II vote, related to the treatment of TMSR. Some suppliers wanted to include a forward TMSR market in ASM Phase II.³⁷⁷

ISO-NE states that some “potential future enhancements are discussed in more detail in Section 7 of the ISO’s 2006 Wholesale Markets Plan.”³⁷⁸

b. The Reserves Market Aspect of PJM’s RPM Proposal

As mentioned above, PJM’s RPM proposal was structured to recognize “the added value of capacity resources that preserve operational aspects of reliability .

370. Market Phase II Letter, *supra* note 360, at 10.

371. *Id.* at 11.

372. Market Phase II Letter, *supra* note 360, at 11.

373. *Id.* at 11.

374. Market Phase II Letter, *supra* note 360, at 9.

375. *Id.* at 14.

376. Market Phase II Letter, *supra* note 360, at 15.

377. *Id.* at 18.

378. Market Phase II Letter, *supra* note 360, at 2.

...³⁷⁹ In particular, prior to the RPM auctions, PJM will determine the region's minimum requirement for capacity capable of adjusting output to follow changes in load, and for capacity capable of starting in 30 minutes or less. PJM will certify units capable of meeting those requirements.

Market sellers with such resources can specify in their offers the added price, if any, they desire to offer these capabilities. If either of the operational reliability constraints bind in the auction, then the price will clear higher as necessary to ensure [that] the minimum required amount of resources, with such capability, are committed in the auction. All generation resources in the region that provide that needed capability then will receive the same price adder.

To ensure the capability is provided, resources committed in the auctions to resolve the operational reliability constraints must pass capability tests in the Delivery Year, and must specify and offer such capabilities in their offer data for the PJM energy market.³⁸⁰

While many parties had comments and/or protests concerning various aspects of PJM's RPM proposal, there was little comment on the reserve market features of the proposal.

3. Reactive Power Service

In Opinion No. 440, the Commission approved a methodology presented by American Electric Power Service Corporation (AEP) for generators to recover costs for reactive power. AEP identified three components of production that are directly related to the production of vars: (1) the generator and its exciter; (2) accessory electric equipment that supports the operation of the generator-exciter; and (3) the remaining total production investment required to provide real power and operate the exciter. Because these plant items produce real and reactive power, AEP developed an allocation factor to segregate the reactive production function from the real power production function.³⁸¹ Subsequently, the Commission directed all generators seeking reactive power recovery that have actual cost data and support to use the AEP methodology.³⁸²

After Opinion No. 440, but prior to *WPS Westwood*, the Commission accepted a proposal by PJM to (1) include revenue requirements of generation owners that are not transmission owners in the charges for reactive power and (2) to allocate reactive power-related revenues to all generation owners.³⁸³ As a result, many independent generators in PJM began to file rate schedules under section 205 of the Federal Power Act specifying their revenue requirements for providing cost-based reactive power. These filings generally followed the AEP methodology (meaning they included the fixed capacity component mentioned above); however, they also incorporated other costs.

For example, in addition to a fixed capability component, FPL Energy also included components for heating losses and lost opportunity costs, respectively, in its proposed revenue requirement.³⁸⁴ Recently, the FPL Energy model was

379. RPM Tariff Filing, *supra* note 233.

380. *Id.* at 78.

381. *Am. Elec. Power Serv. Corp.*, 88 F.E.R.C. ¶ 61,141 (1999), *order on reh'g*, 92 F.E.R.C. ¶ 61,001 (2000).

382. *WPS Westwood*, 101 F.E.R.C. ¶ 61,290 at P 14 (2002).

383. Letter from Alice Fernandez, Director, OMTR/Tariffs and Rates-East, to Carrie L. Bumgarner, Attorney for PJM Interconnection, L.L.C. (Sept. 25, 2000) (Docket No. ER00-3327-000).

384. *FPL Energy*, 96 F.E.R.C. ¶ 61,035 (2001).

adopted by a multitude of generators in the MISO territory that filed rate schedules for reactive power, and by generators seeking compensation under interconnection agreements with transmission owners.³⁸⁵ In fact, from the early part of 2004 to the present, the Commission has been inundated with such filings, the overwhelming majority of which were set for hearing and are still awaiting final disposition on their merits. As a result of these myriad reactive-power, revenue-requirements filings (and the numerous issues raised therein), the Commission, on February 4, 2005, issued a staff report entitled “Principles for Efficient and Reliable Reactive Power Supply and Consumption” (Staff Report).³⁸⁶

Among other things, the Commission’s Staff Report identified the following six problems regarding the current procurement practices and pricing policies for reactive power: (1) discriminatory compensation (i.e., transmission-based suppliers of reactive power receive compensation, yet many generation-based suppliers do not);³⁸⁷ (2) rigid but imprecise interconnection standards that are insensitive to local needs (i.e., interconnection standards generally require a standardized generation power factor for new generation, but local needs often vary from the standards); (3) lack of transparency and consistency in planning and procurement; (4) poor financial incentives to provide or consume reactive power (i.e., the price signals that could facilitate additional reactive power from market participants and load are insufficient); (5) poor incentives for some system operators to procure reactive power and reactive power capability at the least cost; and (6) failure of system operators to adjust reactive power instructions so as to fully optimize dispatch.³⁸⁸

To address these problems, the Staff Report recommends that reactive power reliability needs be assessed locally and procured in an efficient and reliable manner; reactive power beneficiaries should be charged for this service; and all providers of reactive power should be paid, and on a non-discriminatory basis.³⁸⁹

The Staff Report was particularly concerned about the current methods of procuring and compensating generators for reactive power.

[C]urrent rules treat generators differently from other providers of reactive power. Owners of transmission equipment that provide static reactive power capability receive cost-of-service payments through a routine filing process. However, owners of generators are sometimes expected to provide reactive power capability within established ranges without compensation, as a condition of interconnection to the grid.³⁹⁰ In addition, the regulatory process often makes it harder for

385. See e.g., *Troy Energy, LLC*, 105 F.E.R.C. ¶ 61,250 (2003); *Orion Power Midwest L.P.*, 107 F.E.R.C. ¶ 61,216 (2004); *Tenaska Va. Partners*, 107 F.E.R.C. ¶ 61,207 (2004).

386. FED. ENERGY REGULATORY COMM’N, PRINCIPLES FOR EFFICIENT AND RELIABLE REACTIVE POWER SUPPLY AND CONSUMPTION, Docket No. AD05-1-000 (Feb. 2005), available at <http://www.ferc.gov/eventcalendar/Files/20050310144430-02-04-05-reactive-power.pdf> [hereinafter STAFF REPORT].

387. The issue of discrimination under the Order No. 888 *pro forma* OATT has now taken on additional prominence with the Notice of Inquiry issued by the Commission on September 16, 2005, *Preventing Undue Discrimination and Preference in Transmission Services*. Paragraph 29 specifically refers to Schedule 2, Reactive Supply and Voltage Control from Generation Sources Service. Obviously, discrimination against independent generators under an OATT in the recovery of costs for reactive power service would be of great concern to the Commission. Notice of Inquiry, *Preventing Undue Discrimination and Preference in Transmission Services*, F.E.R.C. STATS & REGS. ¶ 35,553 at P 29, 70 Fed. Reg. 55,796 (2005).

388. STAFF REPORT, *supra* note 388, at 4–5.

389. *Id.* at 6.

390. In Order No. 2003, the Commission emphasized that an interconnection customer “should not be

independent generators than for owners of generators that are affiliated with vertically integrated transmission owners to receive compensation for their reactive power capability through routine regulatory filings. Interconnection requirements to provide capability for reactive power provide no compensation in certain locations and this arrangement blunts the incentive to provide this capability.³⁹¹

Accordingly, the Staff Report entreats the Commission to review the current AEP methodology for determining payments for reactive power capability articulated in Opinion No. 440, particularly with respect to its effect on investment incentives.³⁹²

In addition, the Staff Report suggests that the Commission should streamline the process for filing and collecting Opinion No. 440 reactive power rates by independent generators, as the regulatory process they must currently follow is significantly more burdensome and time consuming than the one followed by affiliated generators.³⁹³ Although the Staff Report neither expressly nor tacitly stated as much, it could very well be a portent of future changes the Commission may make to its current policies on reactive power compensation and procurement.

E. Role of the Stakeholder Process

Most ISOs and RTOs integrate stakeholder input into their decision-making and planning processes, whether through a formal stakeholder Board of Governors and Advisory Committees or through informal stakeholder meetings and discussions.³⁹⁴ The FERC has strongly encouraged RTOs to develop and utilize a stakeholder process.³⁹⁵ In *Alliance Companies*,³⁹⁶ the Commission underscored the importance of meaningful stakeholder input. The Commission pointed out shortcomings to the stakeholder process under Alliance Companies' proposal, including: stakeholders were limited in their ability to consult with each other and were potentially subject to confidentiality requirements; and Alliance had control over aspects of membership eligibility, voting, and the formation of new stakeholder groups due to its proposal to limit stakeholder

compensated for reactive power when operating its generating facility within the established power factor range, since it is only meeting its obligation." Order No. 2003, *Standardization of Generator Interconnection Agreements and Procedures*, F.E.R.C. STATS. & REGS. ¶ 31,146 at P 546 (2003), 68 Fed. Reg. 49,845 (2003) (codified at 18 C.F.R. § 35), *order on reh'g*, Order No. 2003-A, F.E.R.C. STATS. & REGS. ¶ 31,160 (2004), 69 Fed. Reg. 15,932 (2004) [hereinafter Order No. 2003-A], *order on reh'g*, Order No. 2003-B, F.E.R.C. STATS. & REGS. ¶ 31,171 (2005), 70 Fed. Reg. 265 (2005). However, the Commission required the transmission provider or RTO/ISO to compensate the interconnection customer for real and reactive power or other emergency condition services that the interconnection customer provides to support the transmission system during an emergency situation. In response to concerns of discrimination between transmission-based and generation-based suppliers of reactive power, the Commission clarified in Order No. 2003-A that where a transmission provider compensates its own or affiliated generators for reactive power within the established power range, it must also compensate non-affiliated generators for the same service. *See* Order No. 2003-A, *supra*, at P 416.

391. STAFF REPORT, *supra* note 388, at 14.

392. *Id.*

393. STAFF REPORT, *supra* note 388, at 14.

394. For a summary of information on Stakeholder Processes in existing and proposed RTOs and ISOs, *see* FED. ENERGY REGULATORY COMM'N, RTO—EXAMPLES OF STAKEHOLDER PROCESSES AND REGIONAL STATE COMMITTEES' PRACTICES (2005), available at <http://www.ferc.gov/industries/electric/indus-act/rto/examples.asp> [hereinafter Examples of Stakeholder].

395. SAM RANDAZZO, MCNESS WALLACE & NURICK LLC, SPOTLIGHT ON THE RTO BOARD: GOVERNANCE (2002), available at <http://www.ksg.harvard.edu/hepg/Papers/Randazzo%20RTO%20Gov%204-02%20Atlanta.pdf>.

396. *Alliance Cos.*, 94 F.E.R.C. ¶ 61,070, at p. 61,304 (2001).

communications through mandated confidentiality agreements. According to the Commission:

[t]he processes that stakeholders can use to communicate and consult with an RTO should be developed in consultation with stakeholders. If RTOs are to be responsive to the needs of the market, there must be a meaningful and efficient process for communication and consultation that serves not only the needs of the RTO, but also the needs of stakeholders.³⁹⁷

The Commission found that requiring Alliance to unilaterally propose stakeholder processes and having the Commission direct changes based on stakeholder comments was not an ideal approach to develop workable processes for stakeholder communication and consultation. According to the Commission, “a better approach is . . . to develop an advisory process in consultation with stakeholders, and to describe that advisory process and identify the participants. Only if they cannot will the Commission step in.”³⁹⁸

Later in the same proceeding, the FERC reiterated that an effective stakeholder process is of utmost importance. It expressed “serious concerns” regarding the stakeholder processes and underscored that stakeholders should have input into aspects of RTO formation necessary to develop practices that foster a seamless marketplace. While the Commission did not wish to “micro manage” the stakeholder process, the FERC found that Alliance’s stakeholder process was deficient and, because the stakeholder processes were key to resolving issues, the FERC ordered the Alliance Companies to resolve the issue immediately.³⁹⁹

The FERC has supported stakeholder input “particularly in those situations involving market design or the modification of market structures or protocols that impact all stakeholders.”⁴⁰⁰ In *Consolidated Edison of New York, Inc.*,⁴⁰¹ the Commission rejected certain revised market power mitigation measures that ConEd introduced on its own motion. Among several significant issues that the FERC confronted in assessing the proposal, the FERC was concerned that “ConEd circumvented the NYISO stakeholder process by unilaterally filing . . . [the] measures.”⁴⁰² The FERC stated: “ConEd’s failure to use the NYISO stakeholder process has resulted in vigorous opposition to its proposal. We strongly encourage market participants to use the stakeholder process, especially in this type of situation, *i.e.*, where a market participant seeks to modify market measures that impact all market participants.”⁴⁰³ The FERC’s rejection was without prejudice to refiling after the proposed revisions have first been considered through the NYISO stakeholder process.

Moreover, the 148 input take place before issues are presented to the Commission:

More generally speaking, in Order No. 2000, the Commission stated that, where there is a non-stakeholder governing board, as is the case here, it is important that the board not become isolated. The Commission found that both formal and informal mechanisms must exist to ensure that stakeholders can convey their

397. RANDAZZO, *supra* note 397, at 14 (quoting *Alliance Cos.*, 94 F.E.R.C. ¶ 61,070, at p. 61,304 (2001)).

398. *Id.*

399. RANDAZZO, *supra* note 397, at 14–15 (quoting *Alliance Cos.*, 96 F.E.R.C. ¶ 61,052, at p. 61,146 (2001)).

400. *Id.* at 14.

401. *Consolidated Edison Co. of N.Y., Inc.*, 95 F.E.R.C. ¶ 61,216, at p. 61,719 (2001).

402. *Id.*

403. RANDAZZO, *supra* note 397, at 14 (quoting 95 FERC ¶ 61,216, at p. 61,719).

concerns to the non-stakeholder board. We believe that stakeholder consultation facilitates the effective development and management of OATTs and Business Practices, and results in issues being resolved among the parties and thus in fewer and more focused issues being presented for Commission consideration. The Midwest ISO Agreement contains such mechanisms for Midwest ISO and stakeholders to consult with each other, and provides opportunities for stakeholders to participate in a collaborative process in the development of the Midwest ISO OATT and Business Practices. We expect Midwest ISO to utilize this stakeholder advisory process to the greatest extent possible. Likewise, we expect stakeholders to fully participate in the stakeholder process, within the limits of their resources, in order to ensure that their concerns are raised in a timely manner.⁴⁰⁴

Recently, the Commission has expressed concern that the voice of stakeholders is “not as loud” as it needs to be.⁴⁰⁵ Referring to a paper released in December, 2004 by the American Public Power Association (APPA) and a privately released report from a group of industrial customers in PJM, then-Commissioner Kelliher was quoted as saying that the FERC “‘should express willingness’ to give stakeholders a stronger voice on the RTO boards.”⁴⁰⁶

In its report, the APPA stated that substantial “mid-course corrections” to FERC’s policies are needed to fix existing RTOs and to encourage non-RTO alternatives in those regions where they are not likely to form.⁴⁰⁷ According to the APPA, four of the five current RTOs have independent boards. “[The] FERC’s reason for requiring independent boards was a good one: to avoid RTO governance structures that could be ‘captured’ by one or a few industry sectors, leading to bias in RTO operations and transmission service provision.”⁴⁰⁸ However, the APPA reports that “APPA members’ experience with independent RTO boards shows that there [are drawbacks]” to independent RTO boards as well.⁴⁰⁹

First, the report states that “independent RTO boards can lack direct accountability to the industry participants in the RTO’s region and to the electric consumers the RTO ultimately serves.”⁴¹⁰ According to the report, “APPA members have seen RTO boards vote to take actions that a very substantial majority of industry stakeholders in their own regions vehemently opposed.”⁴¹¹ Such activity, if it occurs repeatedly, could result in a loss of confidence in RTO actions by industry participants. The APPA reports that this could be very damaging for the RTO in the long run. To operate effectively, the APPA states that RTOs must gain the respect of all industry participants through RTO board and management accountability.

Second, the report notes that some independent boards seem to rely to a very significant degree upon RTO management and sometimes inexperienced staff. According to the report, this can lead to insufficient oversight. Recent

404. *Id.* at 15 (quoting *Cargill-Alliant, LLC*, 98 F.E.R.C. ¶ 61,148, at pp. 61,506–07 (2002) (internal citations omitted)).

405. ‘We Need to Listen,’ Kelliher Says of Concerns About RTO Markets, PLATTS TRANSMISSION & DISTRIBUTION, Feb. 1, 2005, available at http://www.platts.com/Magazines/Platts%20T&D/News%20Archive/2005/020105_5.xml [hereinafter *We Need to Listen*].

406. *Id.*

407. AM. PUB. POWER ASS’N, RESTRUCTURING AT THE CROSSROADS: FERC ELECTRIC POLICY RECONSIDERED 2 (2004) [hereinafter *RESTRUCTURING AT THE CROSSROADS*].

408. *Id.* at 17.

409. *RESTRUCTURING AT THE CROSSROADS*, *supra* note 409, at 17.

410. *Id.*

411. *RESTRUCTURING AT THE CROSSROADS*, *supra* note 409.

corporate governance scandals “point out the need to avoid boards that are too dependent on management and staff, without independent knowledge of what is happening ‘on the ground,’ both within their own RTO organization and in the RTO’s region.”⁴¹²

The APPA report notes that such lack of accountability to customers and stakeholders creates the widely held perception that the FERC is the RTO’s only stakeholder, damaging the credibility of both the FERC and the respective RTOs.⁴¹³

The APPA report recommends that the FERC and the RTOs promote an atmosphere of mutual respect and constructive relations between RTOs and the industry participants. While the APPA cautions that RTO management and boards cannot be subservient to industry participants, “they should not be able to simply ignore them.”⁴¹⁴ Finally, it recommends that the FERC “vigorously regulate RTOs . . . to ensure that they meet their responsibilities to industry participants and electric consumers.”⁴¹⁵

“Kelliher suggested that the [Commission] consider promoting hybrid boards that consist mostly of independent officers, but that also give stakeholders ‘a bigger voice.’”⁴¹⁶ Kelliher pointed to experiences in late 2000 with a CAISO stakeholder board that was often deadlocked during the Western energy crisis, stating that the FERC may have overreacted to the problem by cutting off stakeholder participation in RTO boards as a general policy.⁴¹⁷ As a result, Kelliher said, RTO boards have often been managed by officials who may not fully understand the needs of their customers.⁴¹⁸

F. Prohibition of Energy Market Manipulation and the Role of Market Monitors

ISOs and RTOs have the basic authority, as described in *NRG Power Marketing, Inc. v. NYISO*,⁴¹⁹ to correct all prices that do not reflect operation of the ISO market rules (which are the filed rate). Beyond this authority, several ISOs, such as ISO-NE and NYISO, had broad authority when they commenced operations to correct market design implementation flaws. However, this sort of authority was viewed as a temporary measure to assist in the initial implementation of the markets. In the case of ISO-NE and its authority to correct such flaws under its Market Rule 15, the Commission stated that:

Market Rule 15, accepted by the Commission in Docket No. ER99-2175-000,⁴²⁰ authorizes the ISO to take emergency corrective actions to address market design and implementation flaws. Market Rule 15 originally was scheduled to terminate July 31, 1999. However, because the ISO was continuing to experience market design problems (i.e., inaccurate clearing prices in the Energy and Operable Capability markets), the Commission granted NEPOOL’s request to extend Market Rule 15 through September 30, 1999 in Docket No. ER99-4030-000,⁴²¹ NEPOOL

412. *Id.* at 17–18.

413. RESTRUCTURING AT THE CROSSROADS, *supra* note 409, at 17–18.

414. *Id.* at 18.

415. RESTRUCTURING AT THE CROSSROADS, *supra* note 409, at 18.

416. We Need to Listen, *supra* note 407.

417. *Id.*

418. We Need to Listen, *supra* note 407.

419. *NRG Power Mktg., Inc.*, 91 F.E.R.C. ¶ 61,346 (2000).

420. *New England Power Pool*, 87 F.E.R.C. ¶ 61,055 (1997).

421. *New England Power Pool*, 88 F.E.R.C. ¶ 61,315 (1999).

now proposes an additional 60-day extension of Market Rule 15 through November 29, 1999.⁴²²

The FERC denied NEPOOL's proposed extension of Market Rule 15.

Similar to Market Rule 15, NYISO's Temporary Extraordinary Procedures (TEP) were implemented to address market design flaws and transitional abnormalities encountered during the first ninety days of NYISO's operations (which commenced on November 18, 1999). NYISO's TEP were extended several times, most recently on October 25, 2001, "until the Northeastern RTO is operational and operating pursuant to market rules as established in the Final Rule issued in the Commission's RTO market design and market structure rulemaking."⁴²³ NYISO obtained "a waiver of its TEP to allow it sufficient time to . . . recalculate invalid prices that were posted during the period its markets were disrupted by the outage that began on August 14, 2003."⁴²⁴ In concurring with FERC's March 4, 2005 Order on Remand, then-Commissioner Kelliher addressed what he believed "is the more significant question underlying this order, namely whether the TEP itself constitutes an improper delegation to the NYISO of the Commission's authority under Section 205" of the FPA.⁴²⁵

Chairman Kelliher's concern over the role of ISO/RTOs and their market monitors in mitigating prices is also reflected in the Commission's ongoing investigation of market power mitigation reference prices.⁴²⁶ On April 1, 2005, the Commission issued a Notice Inviting Comments on the Establishment and Use of Reference Prices. The comments filed generally supported the existing use of reference prices by RTOs and ISOs. This policy statement proceeding is not, however, attempting to address the problem that the court in *Edison Mission v. FERC*⁴²⁷ found in using reference prices in an automated mitigation mechanism to control prices in an unconstrained market (in New York): a failure to distinguish high prices resulting from scarcity versus those resulting from the exercise of market power. Nor did the Commission address this issue in its Order on Remand following the *Edison Mission* decision. Rather, in its June 16, 2005 order in that proceeding,⁴²⁸ the Commission simply directed NYISO to revise its tariff so that the mechanism did not operate in unconstrained areas.

On May 27, 2005, the Commission issued a Policy Statement on Market Monitoring Units (MMUs) to provide guidance on the coordinated roles and responsibilities of the Commission and the MMUs.⁴²⁹ Among other things, the

422. *ISO New England Inc.*, 89 F.E.R.C. ¶ 61,209 (1999).

423. *N.Y. Indep. Sys. Operator, Inc.*, 97 F.E.R.C. ¶ 61,095, at p. 61,493 (2001).

424. *N.Y. Indep. Sys. Operator, Inc.*, 104 F.E.R.C. ¶ 61,214 (2003).

425. *N.Y. Indep. Sys. Operator, Inc.*, 110 F.E.R.C. ¶ 61,244 (2005).

426. Cf. Hon. Sudeen Kelly, Maria F. Vouras, & Jennifer S. Amerkhail, *The Subdelegation Doctrine and the Application of Reference Prices in Mitigating Market Power*, 26 ENERGY L.J. 297 (2005).

We find that the exercise of discretion by the market monitoring units in determining reference prices is a permissible delegation of the Commission's ratemaking authority under the subdelegation doctrine because: (1) the Commission has provided "objective criteria" for the market monitoring units to apply in exercising their discretion, i.e., reference prices should represent a resource's marginal costs; (2) the Commission has a "reasonable basis" for allowing market monitoring units to exercise discretion that is limited in scope, i.e., market monitoring units are independent experts who can provide timely responses to exercises of market power; and (3) the Commission retains the authority to provide timely and assured review of discretionary decisions by market monitoring units.

Id. at 325.

427. *Edison Mission v. FERC*, 394 F.3d 964 (D.C. Cir. 2005).

428. *N.Y. Indep. Sys. Operator, Inc.*, 111 F.E.R.C. ¶ 61,399 (2005).

429. *Policy Statement on Mkt. Monitoring Units*, 111 F.E.R.C. ¶ 61,267 (2005).

Commission stated that “MMUs should evaluate the market-specific responses of individual market participants to existing or proposed market rules and tariff provisions.”⁴³⁰ The Commission believed that it therefore is “critical that the MMU consistently and impartially evaluate the existing ISO/RTO rules and tariff provisions, including mitigation and their effects on the economic signals sent to market participants.”⁴³¹ However, the Commission clarified, it is the responsibility of the ISO/RTO to make section 205 filings, rather than the MMU.

The Commission also determined that ISOs/RTOs may administer compliance with tariff provisions only if they are expressly set forth in the tariff; involve objectively identifiable behavior; and do not subject the seller to sanctions or consequences other than those expressly approved by the Commission and set forth in the tariff, with the right of appeal to the Commission.⁴³² The Commission explained that these penalties must be designed to be a clear deterrent to unwanted behavior, without being so high as to be unnecessarily punitive. The Commission also stated that if the MMU finds that an action by a market participant may require investigation and evaluation, may be a potential violation of a market rule contained in an ISO/RTO-filed tariff, or may be a violation of the Market Behavior Rules, the MMU should notify the Commission staff.⁴³³

The uncertainty concerning the ISO/RTOs’ and their market monitors’ market power mitigation enforcement authority created by the reference price policy statement proceeding described above is increased by the Commission’s efforts to implement Section 222 of EAct 2005 which prohibits market manipulation and allows the Commission to issue implementing regulations.⁴³⁴ On October 20, 2005, the Commission issued a Notice of Proposed Rulemaking on the Prohibition of Energy Market Manipulation. The Commission stated that its proposed addition to the regulations is patterned on the SEC’s Rule 10b-5, which was promulgated to enforce Section 10(b) of the Securities and Exchange Act, and which the Supreme Court has found to be “analogous” to Section 4b of the Commodity Exchange Act, which is the Commodity Futures Trading Commission’s general anti-fraud rule.⁴³⁵

The proposed addition to electricity regulations would prohibit the use or employment of any manipulative or deceptive device, scheme, or artifice to defraud any person in connection with the purchase or sale of electric energy, or transmission services subject to the FERC’s jurisdiction.

While the precise role of ISOs/RTOs and their market monitoring units in preventing market manipulation necessarily is now somewhat uncertain, it is likely that the Commission will expect that whatever authority it ultimately will

430. *Id.* at P 3.

431. *Mkt. Monitoring Units in Reg’l Transmission Orgs. and Indep. Sys. Operators*, 111 F.E.R.C. ¶ 61,267 at P 3 (2005).

432. *Id.* at P 5.

433. 111 F.E.R.C. ¶ 61,267 at P 6.

434. The need for the Commission to have additional authority to prevent market manipulation such as that given to it by Section 222 of EAct 2005 was forcefully argued in Hon. Joseph T. Kelliher, *Market Manipulation, Market Power, and the Authority of the Federal Energy Regulatory Commission*, 26 ENERGY L.J. 1 (2005).

435. THOMAS GALLO, ROBINS, KAPLAN, MILLER & CIRELLI L.L.P., CLAIMS UNDER SECTION 10(B) OF THE SECURITIES EXCHANGE ACT OF 1934 AND RULE 10B-5 (Mar. 9, 2005), available at http://www.rkmc.com/Claims_Under_Section_10B_of_the_Securities_Exchange_Act_of_1934_and_Rule_10b_5.htm (describing what is necessary to succeed on a Rule 10b-5 fraud claim).

have should be exercised considering the same factors which the Commission has stated that it will use in enforcing EPCA 2005. On October 20, 2005, the Commission also issued a Policy Statement on Enforcement which described the factors the Commission will take into account in determining remedies available under EPCA 2005 for violations of the Commission's rules.

In that Policy Statement, the Commission stated that, as mandated by sections 316A of the FPA and new section 22 of the NGA, the seriousness of the offense is the first consideration in determining appropriate penalties. Other factors that may be considered in judging the seriousness of the offense include: What harm was caused by the violation? Was the violation the result of manipulation, deceit, or artifice? Was the action willful? Is this a repeat offense or does the company have a history of violations?

The Commission on January 19, 2006, issued a Final Rule on Prohibition of Energy Market Manipulation in which it amended its regulations to prohibit the employment of manipulative or deceptive devices or contrivances in accordance with EPCA 2005.⁴³⁶ The Commission clarified the scope of application of the Final Rule; addressed certain comments; discussed the elements of a violation of the Final Rule; noted the relationship of the Final Rule to the Market Behavior Rules; and dealt with a number of implementation issues.

In addition, in its rulemaking to implement Section 222 of EPCA 2005, the Commission stated that it will address the possibility of revising or repealing Market Behavior Rule 2 in the near future. That rule, promulgated in Appendix A of the Commission's November 17, 2003 Order Amending Market-Based Rate Tariffs and Authorizations, reads as follows:

2. **Market Manipulation:** Actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules for electric energy or electricity products are prohibited. Actions or transactions undertaken by Seller that are explicitly contemplated in Commission-approved rules and regulations of an applicable power market (such as virtual supply or load bidding) or taken at the direction of an ISO or RTO are not in violation of this Market Behavior Rule. Prohibited actions and transactions include, but are not limited to:

- a. pre-arranged offsetting trades of the same product among the same parties, which involve no economic risk and no net change in beneficial ownership (sometimes called "wash trades");
- b. transactions predicated on submitting false information to transmission providers or other entities responsible for operation of the transmission grid (such as inaccurate load or generation data; or scheduling non-firm service or products sold as firm), unless Seller exercised due diligence to prevent such occurrences;
- c. transactions in which an entity first creates artificial congestion and then purports to relieve such artificial congestion (unless Seller exercised due diligence to prevent such an occurrence); and
- d. collusion with another party for the purpose of manipulating market prices, market conditions, or market rules for electric energy or electricity products.⁴³⁷

436. *Prohibition of Energy Mkt. Manipulation*, 114 F.E.R.C. ¶ 61,047 (2006).

437. *Investigation of Terms and Conditions of Pub. Util. Market-Based Rate Authorizations*, 105 F.E.R.C. ¶ 61,218 at app. A (2003). Market Behavior Rule 2 has been challenged in federal court in *Cinergy Marketing & Trading v. FERC*, Case No. 04-1168, (D.C. Cir. 2004).

On November 21, 2005, the Commission issued an order⁴³⁸ proposing to repeal the Market Behavior Rules, stating that repeal of those rules will simplify the Commission's rules and regulations, avoid confusion, and provide greater clarity and regulatory certainty to the industry. The Commission stated that the Market Behavior Rule 2's prohibition of transactions that could "forseeably" manipulate the market is inferior to the "scienter" requirement used by the Securities and Exchange Administration and proposed by the Commission in its Prohibition of Energy Market Manipulation NOPR.⁴³⁹ There is also a difference in the scope of applicability between existing Market Behavior Rule 2 and the Commission's proposed regulations. EPAct 2005 provides the Commission with authority to police market manipulation by "any entity," including municipally owned utilities and others not typically subject to Commission jurisdiction, while Market Behavior Rule 2 applies only to public utilities with market-based rate and blanket certificate authorities.

1. Procedures for Changing ISO/RTO Market Rules

Whatever changes an ISO or RTO may wish to make to its market manipulation rules (or other market rules) must be done within the bounds of the rules the Commission has established for stating market rules in the tariff and in its market manuals that are not filed with the Commission. In *New England Power Pool and ISO New England Inc.*, the Commission discussed what needs to be in the tariff and what can be in unfiled manuals.⁴⁴⁰ The Commission there required ISO-NE⁴⁴¹ to insert language in its tariff stating that provisions which have a "substantial effect on rates, terms and conditions of service" are filed with the Commission.⁴⁴² The Commission did not, however, require ISO-NE to file its manuals with the Commission, noting that it did not require PJM to do so.⁴⁴³ The Commission was mindful of ISO-NE's need for flexibility to modify manuals as needed. Nor did the Commission require a special appeals process to enable participants to appeal ISO-NE's decision to place material in a manual rather than in its tariff. The Commission further explained that if members wish to appeal ISO-NE's decisions regarding manuals, they may use ISO-NE's⁴⁴⁴ current internal dispute resolution procedures prior to filing a complaint with the Commission.

An example of the difficulties that can arise when there is a question concerning whether necessary provisions, including the effective date, are sufficiently spelled out in an ISO/RTO's tariff is *Consolidated Edison Company*

438. *Investigation of Terms and Conditions of Pub. Util. Market-Based Rate Authorizations*, 113 F.E.R.C. ¶ 61,190 (2005).

439. Notice of Proposed Rulemaking, *Prohibition of Energy Mkt. Manipulation*, F.E.R.C. STATS. & REGS. ¶ 32,591, 70 Fed. Reg. 61,930 (2005).

440. *New England Power Pool*, 100 F.E.R.C. ¶ 61,287 (2002).

441. At the time of this order, the relevant tariff provisions were in the NEPOOL tariff. Since the establishment of ISO-NE as an RTO, such provisions are now in the ISO-NE tariff.

442. 100 F.E.R.C. ¶ 61,287.

443. *PJM Interconnection*, 81 F.E.R.C. ¶ 61,257, at pp. 61,241-42 (1997). It did, however, require CAISO to file.

444. Since the relevant tariff provisions were then in NEPOOL's tariff, the Commission phrased its discussion in terms of "NEPOOL's current internal dispute resolution procedures under the NEPOOL Agreement." 100 F.E.R.C. ¶ 61,297 at P 147. However, that discussion presumably would apply to ISO-NE's dispute resolution procedures now since ISO-NE's market rules are set forth in its tariff and not in a NEPOOL tariff.

of *New York, Inc. v. New York Independent System Operator*.⁴⁴⁵ In that case, complainants sought \$21 million in refunds alleging that certain ICAP rebates were not properly computed in accord with NYISO's tariff. The problem arose because NYISO's tariff provisions concerning the calculation and allocation of ICAP rebates was not clear and NYISO conducted three auctions to implement the LICAP proposal after NYISO had filed the proposal on March 21, 2003, but before the Commission approved it by order issued May 20, 2003,⁴⁴⁶ and allowed it to go into effect on May 21, 2003. The Commission found that NYISO's computation of refunds was consistent with its tariff and that Complainants received adequate notice because of NYISO's request that the Commission approve implementation of the change before the summer of 2003.

G. Cost Effectiveness

While the theory of a large market administered by an independent grid operator may have substantial appeal, some have expressed concern about whether RTOs and ISOs have lived up to initial expectations, and whether, as a general matter, they are cost effective. The American Public Power Association asserts that "[its] members located in RTO regions report substantial, across-the-board problems with spiraling RTO costs, unaccountable governance, lack of understanding of transmission customer and end-user needs and less-than-satisfactory service options."⁴⁴⁷ Louisville Gas and Electric Company (Louisville) has asserted that its Independent Transmission Organization/Reliability Coordinator proposal will satisfy Order No. 888 requirements at a lower cost than would continued membership in MISO.⁴⁴⁸ In contrast, while asserting that the implementation of deregulation could be vastly improved, a recent study by Cambridge Energy Research Associates challenges the "conventional wisdom" that residential customers have not benefited from electric restructuring and maintains that restructuring saved them \$34 billion.⁴⁴⁹

445. *Consolidated Edison Co. of N.Y., Inc.*, 108 F.E.R.C. ¶ 61,059 (2004). See also *N.Y. Indep. Sys. Operator, Inc.*, 91 F.E.R.C. ¶ 61,218 (2000), *reh'g denied*, 97 F.E.R.C. ¶ 61,155 (2001), *reh'g denied*, 99 F.E.R.C. ¶ 61,125 (2001), *aff'd in part and remanded in part*, *Consolidated Edison Co. of N.Y. v. FERC*, 347 F.3d 964 (D.C. Cir. 2003), *order on remand*, *N.Y. Indep. Sys. Operator, Inc.*, 110 F.E.R.C. ¶ 61,244 (2005), *order on reh'g*, 113 F.E.R.C. ¶ 61,155 (2005).

446. *N.Y. Indep. Sys. Operator, Inc.*, 103 F.E.R.C. ¶ 61,201 (2003), *reh'g denied*, 105 F.E.R.C. ¶ 61,108 (2003), *aff'd Elec. Consumers Res. Council v. FERC*, 407 F.3d 1232 (D.C. Cir. 2005).

447. RESTRUCTURING AT THE CROSSROADS, *supra* note 409, at 6.

448. Louisville Transmittal Letter, *supra* note 140. In its November 15, 2005 protest of Louisville's filing, MISO asserts, among other things, that Louisville's customers received a net benefit of \$25 million from Louisville's participation in MISO's Day 2 markets over the April – June 2005 period, Motion to Intervene and Protest of the Midwest Independent Transmission System Operator, Inc., FERC Docket Nos. EC06-04-000, ER 06-20-000, at 46 (Nov. 15, 2005) [hereinafter MISO Motion], that its proposal to rely on Transmission Loading Relief procedures is an inefficient step backward, *id.* at 22–29, and that under its proposal Louisville would receive reliability, MISO Motion, *supra*, at 34–37, and market participation benefits from MISO and its market participants without sharing in the costs incurred to provide such benefits. *Id.* at 47–48.

449. CERA Finds Big Savings for Customers but Gives Electric Restructuring C+ Grade 5, INSIDE FERC, Oct. 24, 2005. See also ISO/RTO COUNCIL, THE VALUE OF INDEPENDENT REGIONAL GRID OPERATORS 25–26 (Nov. 2005), available at http://www.nyiso.com/public/webdocs/newsroom/press_releases/2005/isortowhitepaper_final11112005.pdf, (discussing CERA Reports Online, *Beyond the Crossroads: The Future Direction of Power Industry Restructuring* (Oct. 2005), available at http://cera.ecnext.com/coms2/summary_0236-681_ITM). The ISO/RTO Council Study asserts that ISOs and RTO provide the following benefits: maintain and improve grid reliability; improve operating efficiencies; operate markets that lower customer energy costs; provide fair, independent and open markets and transmission access; and effective regional planning. The Study also asserts that ISO/RTO costs flatten with size and experience. The members of the ISO/RTO Council include the Independent Electricity System Operator (of Ontario), ISO-NE, CAISO, NYISO, SPP, ERCOT, Alberta Electric System Operator, PJM and MISO. *Id.*

The cost effectiveness of RTOs is a complex issue to sort out for at least four reasons. It is difficult to have any certainty about: 1) what would have happened in the absence of an ISO; 2) what has been (and will be) the effect on prices of independent factors, such as the general rise in the cost of generation fuels such as natural gas; 3) the extent to which particular complaining parties may have been uniquely disadvantaged while most market participants may have had generally favorable results;⁴⁵⁰ and 4) the savings that can be achieved by the RTO taking over certain utility functions, such as operating the OASIS sites of utilities within its footprint, and by assisting the Commission with some of its functions, such as market monitoring. Louisville did not address these issues in its proposal to withdraw from MISO, but as a utility providing very low cost power, Louisville may not have as much as other utilities to gain from RTO markets.⁴⁵¹

Another complication is the presence of large economies of scale in RTO operation. PJM will find it much easier than other RTOs to maintain low unit rates since its costs are now spread across one fifth of the U.S. economy.⁴⁵² However, there may be limits to the apparent economies of scale of PJM (or possibly RTOs in general). MISO and PJM stated in a compliance filing that:

the cost of implementing these three interrelated initiatives [that would create a single MISO/PJM energy market] is not justified by the incremental benefits that a single market would create. The enormous cost to implement these initiatives would total approximately \$105,000,000, plus ongoing operating costs of \$7,000,000. . . . Also, the technological feasibility of implementing the entire package of applications to support a 247,000 MW market is unproven.⁴⁵³

In contrast to the benefits of an RTO, the dollar costs of RTO operation are quite visible and easily quantified. In a report issued in October of 2004, Commission Staff found: the direct impact of a new Day One RTO should be less than one-half of one percent of a retail customer's bill; to date, Day One RTOs have required an investment outlay of between \$38 million and \$117 million and an annual revenue requirement of between \$35 million and \$78 million; many of the costs are for reliability-related functions; cost overruns can result from changing plans mid-course, poor project management and extensive

450. Certain of the costs related to the unique impact on particular market participants may be minimized or even eliminated through the appropriate allocation of Financial Transmission Rights (FTRs) and the grandfathering of existing arrangements. However, as the protracted proceedings in MISO Docket No. EL04-104 indicate, such measures are not always simple or without controversy, and their effectiveness may be disputed.

451. Louisville Transmittal Letter, *supra* note 140, at 8.

452. For additional views concerning the cost effectiveness of PJM and the economies of scale of large RTOs, see EDWARD N. KRAPELS & PAUL FLEMMING, ENERGY SEC. ANALYSIS INC., IMPACTS OF THE PJM RTO MARKET EXPANSION (Nov. 2005), available at <http://www.pjm.com/documents/downloads/reports/20051101-impact-pjm-expansion.pdf>; see also Mary O'Driscoll, As PJM points to savings, power users decry lack of competition, GREENWIRE, Nov. 11, 2005, available at <http://www.eenews.net/Greenwire/2005/11/11/archive/3/?terms=As%20PJM%20points%20to%20savings,%20power%20users%20decry%20lack%20of%20competition> (reporting on a PJM-sponsored study, and the generally opposing remarks of John Anderson, President of the Electricity Consumers Resource Council, which represents large industrial power users).

453. Letter from Steven R. Pincus, Counsel for PJM Interconnection, L.L.C., to the Honorable Magalie Roman Salas, Sec'y, Fed. Energy Regulatory Comm'n, at 49 (Oct. 31, 2005) (transmittal letter regarding the Commission's Order of March 3, 2005, Docket No. ER04-375-017). This joint filing was vigorously protested by the WPS Companies who, in the alternative, characterized their filing as a complaint (which the Commission has docketed as Docket No. EL06-20-000) and requested that MISO be required to prepare a new plan for the establishment of a joint market.

delays; and cost data are not accounted for in a standardized way.⁴⁵⁴

Recognizing differences in the exact structure, function and development of various RTOs and ISOs, and differences between ISOs/RTOs and investor owned utilities, the Commission instituted a rulemaking proceeding to review: whether RTOs and ISOs have appropriate incentives to be cost efficient; whether the Commission's rate review methods for RTOs and ISOs are sufficient;⁴⁵⁵ and whether changes are needed to the uniform accounting standards,⁴⁵⁶ to better account and report RTO and ISO financial information to the Commission.

In the summer of 2005, the Commission proposed "to amend its regulations to update the accounting requirements for public utilities and licensees, including" RTOs and ISOs.⁴⁵⁷ It also proposed "to amend its financial reporting requirements for the quarterly and annual financial reporting forms for these entities."⁴⁵⁸ "As a result of improved transparency of financial information, the Commission [believed that it] and the public [would] be better able to understand the costs of RTOs."⁴⁵⁹

Various market participants have also vigorously challenged portions of the ISO/RTO costs in cost recovery proceedings relating to specific ISOs or RTOs.⁴⁶⁰ The Florida Public Service Commission is in the midst of an evaluation of the costs and benefits of the GridFlorida RTO proposal.⁴⁶¹ Interestingly, the CAISO has stated its intent to reduce its grid management charge by 15% in 2006,⁴⁶² and PJM filed on July 1, 2005 a rate proposal in which it asserts, *inter alia*, that it "is challenging itself to reduce its costs by over \$100 million over the next five years"⁴⁶³ and "expects to be able to maintain the

454. FED. ENERGY REGULATORY COMM'N, STAFF REPORT ON COST RANGES FOR THE DEVELOPMENT AND OPERATION OF A DAY ONE REGIONAL TRANSMISSION ORGANIZATION ii-iii, Docket No. PL04-16-000 (2004). Staff assumed that the costs of a Day One RTO were the costs "associated with independent control of the regional transmission grid for the non-discriminatory and transparent provision of transmission service." *Id.* at 2.

455. Notice of Inquiry, *Financial Reporting and Cost Accounting, Oversight and Recovery Practices for Regional Transmission Organizations and Independent System Operators*, F.E.R.C. STATS & REGS. ¶ 35,546 at P 1, 69 Fed. Reg. 58,112 (2004). The Commission also generally examined how credit-related issues may affect ISO/RTO costs in *Policy Statement on Electric Creditworthiness*, 109 F.E.R.C. ¶ 61,186 (2004).

456. Notice of Proposed Rulemaking, *Accounting and Financial Reporting for Public Utilities Including RTOs*, F.E.R.C. STATS & REGS. ¶ 32,585, 70 Fed. Reg. 36,865 (2005) [hereinafter Notice of Proposed Rulemaking].

457. *Id.*

458. Notice of Proposed Rulemaking, *supra* note 458.

459. *Id.*

460. See *ISO New England Inc.*, 111 F.E.R.C. ¶ 61,096 (2005); see also *ISO New England Inc.*, 113 F.E.R.C. ¶ 61,341 (2005).

461. See Workshop Transcript, In re *Review of GridFlorida Regional Transmission Organization Proposal* (May 23, 2005) (Docket No. 020233-EL). The purpose of the workshop was to "discuss and hear comments from stakeholders on at least the preliminary draft of the Cost Benefit Study on GridFlorida." *Id.* at 3:12-14. The GridFlorida RTO has been proposed jointly [BY, FOR OR AS] Florida Power & Light Company, Progress Energy Florida, and Tampa Electric Company. GridFlorida filed its initial FERC application in Docket No. RT01-67-000 on October 16, 2000. The Commission issued an Order Provisionally Granting RTO status to GridFlorida on March 28, 2001. *GridFlorida LLC*, 94 F.E.R.C. ¶ 61,363 (2001), *order on reh'g*, 95 F.E.R.C. ¶ 61,473 (2001). On August 22, 2005, the Florida Municipal Power Agency, Seminole Electric Cooperative, Inc., Calpine, and Northern Star Energy proposed a Florida Independent Transmission Provider, and several parties have filed comments on that proposal in the Florida proceeding.

462. Press Release, Cal. ISO, ISO Toll for Using Power Grid to Roll Back Below 1998 Level (July 13, 2005), available at <http://www.caiso.com/docs/2005/07/13/2005071314470615178.pdf>.

463. Letter from Barry Spector, Wright and Talisman, P.C., to the Honorable Magalie Roman Salas, Sec'y, Fed. Energy Regulatory Comm'n (July 1, 2005) (transmittal letter regarding revising and clarifying the terms concerning the provision of information by PJM to the PJM Finance Committee, Docket No. ER05-1181-000).

proposed stated rates in effect for at least five years.”⁴⁶⁴

Regardless of their stated purpose, two provisions of EPAct 2005 may operate to raise issues concerning the cost effectiveness of RTOs. However, in contrast to how the previously-described cost effectiveness issues have arisen, these provisions appear to allow RTOs to make a much more positive case for their benefits rather than primarily requiring them to defend against allegations that the current costs of RTOs exceed their benefits.

Section 1234 of EPAct 2005, entitled “Study on the Benefits of Economic Dispatch” requires the Secretary of Energy, in coordination and consultation with the states, to conduct a study of the current procedures “used by electric utilities to perform economic dispatch.”⁴⁶⁵ The study should identify “possible revisions to the procedures to improve the ability of non-utility generation resources to offer their output for sale[,]” and the potential benefits to consumers if such provisions were revised.⁴⁶⁶ Presumably, one of the “revisions” to existing procedures which would “improve the ability of non-utility generation resources to offer their output” for sale would be to adopt the region-wide economic dispatch of an RTO.⁴⁶⁷ In parallel, Section 1298 of the Act requires the Commission to convene joint boards (consisting of FERC Commissioners and representatives nominated by the states) “to study the issue of security constrained economic dispatch for the various market regions,” and report back to Congress within a year.⁴⁶⁸ The Commission stated that “[t]he joint boards should take into account the DOE report as they proceed with their own efforts.”⁴⁶⁹

Similarly, the Commission’s Electric Energy Market Competition Task Force (Task Force) proceeding provides a forum to assess various RTO and ISO actions, and to allow RTOs and ISOs to explain how they can encourage competition. Section 1815 of EPAct 2005 requires a special Task Force to conduct a study of competition in wholesale and retail markets for electric energy in the United States. On October 13, 2005, the Commission requested comments on dozens of questions listed under the following subject areas: Wholesale Supply Trading and Participation, Generation Ownership, Generation Adequacy, Transmission Investment and Regulation, Wholesale Market Transparency and Information, Retail Markets Overview, State Retail Choice Experience, Retail Supply Questions in States with Retail Competition, Demand Side Participation, and Rising Fuel Prices.

H. Profit vs. Non Profit Nature of RTOs, ITCs and Other Transmission Organizations.

To date, several non-profit ISOs have been formed to integrate markets in the Northeast, Midwest, and California, while at the same time, some Midwest states have seen the formation of for-profit independent transmission companies

464. *Id.* at 10.

465. *See* Energy Policy Act of 2005 § 1234(a)(1), Pub. L. No. 109-58, 119 Stat. 594 (to be codified at 16 U.S.C. § 824s(c)).

466. *Id.*

467. *See* Energy Policy Act of 2005 § 1234(a)(3), Pub. L. No. 109-58, 119 Stat. 594 (to be codified at 16 U.S.C. § 824s(c)).

468. *Id.* § 1298(a).

469. *Joint Boards on Security Constrained Economic Dispatch*, 112 F.E.R.C. ¶ 61,353 at P 15 (2005).

(ITCs) in the hope of increasing transmission investment, and some Southern states have considered hybrid for-profit transmission companies (transcos).

1. Voluntary RTO Participation

While Order No. 2000⁴⁷⁰ required all public utilities owning or operating transmission to file a proposal to form some sort of an RTO (either as a for-profit transco or non-profit ISO or combination of the two) or alternatively to describe efforts to join and participate in an existing RTO, the Commission's goal was to encourage voluntary RTO participation that would be tailored to specific regional needs rather than mandating RTO standardization. The basic purpose of an RTO in the Commission's view was to ensure non-discrimination and open-access to transmission facilities under the RTO and increase reliability of and investment in the transmission system. At the time of Order No. 2000, the focus was to encourage transmission owners to unbundle their transmission from the rest of their assets and "have all transmission-owning entities in the Nation, including non-public utility entities, place their transmission facilities under the control of appropriate RTOs in a timely manner."⁴⁷¹ At the height of debate over RTO development, the Commission's vision was four major RTOs;⁴⁷² it retreated from this position, however, responding to political pressure from Congress and the industry. The current Commission does not view RTO formation in every region as essential to non-discriminatory transmission.

Order No. 2000 encouraged a flexible, "open architecture" approach to the creation of RTOs. Although the Commission's goal remained that every transmission owner join some sort of an RTO, it had to be a voluntary decision made by the transmission owner and the form, "structure, operations, market support and geographic scope" of the organization could vary substantially and change over time.⁴⁷³ Consistent with the Commission's voluntary approach to participation in RTOs, the United States Court of Appeals for the District of Columbia Circuit also found that the Commission cannot require blanket RTO membership.⁴⁷⁴ On occasion, the Commission did offer some sticks and carrots to RTO formation, requiring RTO participation as part of merger approvals⁴⁷⁵ or offering incentive ratemaking treatments.⁴⁷⁶ In EPAct 2005, Congress has specifically required the FERC to provide incentives to entities that join

470. Order No. 2000, *supra* note 5.

471. Order No. 2000-A, *supra* note 5.

472. *PJM Interconnection, LLC*, 96 F.E.R.C. ¶ 61,061 (2001). The Commission stated that "[w]e favor the development of one RTO for the Northeast, one RTO for the Midwest, one RTO for the Southeast and one RTO for the West. Through their independence from market participants, RTOs can ensure truly non-discriminatory transmission service and will instill confidence in the market that will support the billions of dollars of capital investment in generation and demand side projects necessary to support a robust, reliable and competitive electricity marketplace. RTOs are the platform upon which our expectations of the substantial generation cost savings to American customers are based." *Id.* at p. 61,226.

473. Order No. 2000, *supra* note 5, at pp. 31,356, 31,383; Order No. 2000-A, *supra* note 5, at p. 31,356. Although, at the same time, the Commission noted that this should not be interpreted as an "unfettered ability for an RTO to modify its structure or processes." Order No. 2000, *supra* note 5, at p. 31,383.

474. *Atl. City Elec. Co. v. FERC*, 295 F.3d 1 (D.C. Cir. 2002).

475. See e.g., *Am. Elec. Power Co.*, 90 F.E.R.C. ¶ 61,242 (2000); *Louisville Gas & Elec. Co.*, 82 F.E.R.C. ¶ 61,308, at p. 62,214 (1998); *Duke Energy Oakland LLC*, 97 F.E.R.C. ¶ 61,283 (2001); *CP&L Holdings, Inc.*, 92 F.E.R.C. ¶ 61,023, at p. 61,055 (2000).

476. *Proposed Pricing Policy for Efficient Operation and Expansion of Transmission Grid*, 102 F.E.R.C. ¶ 61,032 (2003); *Am. Transmission Co. LLC*, 105 F.E.R.C. ¶ 61,388 (2003). See also Order No. 2000-A, *supra* note 5, at pp. 31,386-87 (specifying that the innovative rate options include "formulary rates, risk adjustments, and rates of return that do not vary with changes in the capital structure").

“Transmission Organizations.”⁴⁷⁷ Congress, however, envisions a much broader range of entities that meet the requirement of a “Transmission Organization,” which is defined to include RTOs, ISOs, independent transmission providers, and other transmission organizations approved by the Commission.⁴⁷⁸

Whether a transmission organization is for profit or non-profit does not appear to matter under EPCA 2005.⁴⁷⁹ Instead, the policy focuses on ensuring that the transmission entity, be it an RTO, ISO, ITC, or other form, meets the requirements of Order No. 2000, most importantly the independence requirement.⁴⁸⁰ In Order No. 2000, the Commission said: “Because ISOs are typically non-profit and non-share corporations, we generally did not have to consider the effect of ownership on the independence of the ISO.”⁴⁸¹ As to for-profit RTOs, the Commission has allowed some passive ownership as long as the

passive owners have relinquished control over operation[], investment and other decisions to ensure that the RTO will treat all users of the grid—passive owners and others—on an equal basis in all matters. The burden of proof is on the RTO to demonstrate that control of the RTO is ‘truly independent’ and that the RTO has a decision making process that is independent of control by the passive owners.⁴⁸²

2. Existing Forms of RTO Participation

Over the past seven years, in reviewing RTO proposals, the Commission has confronted new and different business models, accounting methods, and rate designs for transmission organizations. Currently operating RTOs are not-for-

477. See Energy Policy Act of 2005 § 1241(c), Pub. L. No. 109-58, 119 Stat. 594 (to be codified at 16 U.S.C. § 824s(c)).

478. *Id.* § 1291(b)(29) (to be codified at 16 U.S.C. § 796(29)).

479. In that respect, consistent with EPCA 2005, the Commission has stated that the for-profit or non-profit nature of the transmission organization is irrelevant:

We clarify that our concerns about ownership and control of an RTO are not a function of a for-profit or not-for-profit approach. The limits on ownership by market participants apply whenever the RTO intends to own and operate the transmission assets itself, either directly or indirectly through other entities. The fact that a market participant owner of an RTO operated on a non-profit basis would not, for example, preclude the possibility that the RTO could operate to benefit its generation business. Accordingly, ownership restrictions are appropriate in that case.

Order No. 2000-A, *supra* note 5, at p. 31,364. However, although the Commission’s rejection of the proposed RTO was framed in terms of scope and not independence or any other RTO criterion, the Commission’s order rejecting the proposed Alliance RTO had the practical effect of strongly discouraging for-profit RTOs when issued, since the Alliance proposal was one of the largest and most well-developed for-profit RTO proposals ever filed with the Commission. *Alliance Cos.*, 97 F.E.R.C. ¶ 61,327 (2001).

480. The independence criteria requires that the RTO be separate and independent from the “Market Participants,” defined as sellers/buyers of power and ancillary services, or other entities which the Commission determines to have an economic or commercial interest that would be affected by the RTO’s decisions and actions. 18 C.F.R. § 35.34(b) (2005) A solely wires company (such as an ITC) could have independence in the Commission’s view, and thus such companies were excluded from the definition of “Market Participant.” See Order 2000-A, *supra* note 5. In making the independence finding, the Commission generally determines, on a case by case basis, that: (1) the RTO, its employees and any non-stakeholder directors do not have any economic/financial interests in market participants and energy markets, (2) no market participant or class of participants can affect the voting, governance or the decision-making process of the RTO, and (3) the RTO has exclusive and independent authority under section 205 of the FPA to propose rates, terms and conditions of transmission service. To meet the second condition, i.e., independence for decision-making authority, the Commission explained that it will make a case by case determination, but offered some examples of the factors that would satisfy this condition: “(a) a non-stakeholder governing board and (b) a prohibition on market participants having more than a *de minimis* (one percent) ownership interest in the RTO.” Order No. 2000, *supra* note 5, at pp. 31,046–47.

481. Order No. 2000, *supra* note 5, at p. 31,061.

482. *Id.* at p. 31,066.

profit companies with no shareholder investment. PJM, ISO-NE, NYISO⁴⁸³ and SPP⁴⁸⁴ were formed based on the former tight power pools in their respective regions, while CAISO⁴⁸⁵ and ERCOT⁴⁸⁶ were formed based on state mandates. MISO was neither based on existing pools nor state-mandate, but several Midwest states required traditional utilities to divest their assets and operate under a regional organization. Various states have enacted legislation requiring utilities under their jurisdiction to join such regional organizations.⁴⁸⁷ Many other companies looked into forming ISOs but many attempts failed (i.e., StarISO in Nevada, IndeGo in the Pacific Northwest, MAPP).

Efforts to form for-profit RTOs, in the form of transcos, were concentrated in the Southeast.⁴⁸⁸ For-profit entities that were formed to acquire the transmission assets became known as independent transmission companies (ITCs), basically wires companies. ITCs have been developed as a compromise because the Commission did not see fit, or believe it had authority, to require ISO participation. Because ITC are wires-only companies, they are not affiliated with generation or power marketing activities and thus, would not at least in theory give special treatment (i.e., preferential access) to any market participant. Presently there are three operational ITCs, all having joined larger ISOs, specifically, the MISO. In turn, the Commission has offered various incentives to the ITCs, such as higher ROEs.⁴⁸⁹ The three operational ITCs are: American Transmission Company (ATC),⁴⁹⁰ International Transmission Company (International)⁴⁹¹ and Trans-Elect, Inc. (Trans-Elect).⁴⁹² GridAmerica LLC,

483. NYISO has not filed to become an RTO. *See generally supra* note 129 and accompanying text.

484. SPP has been authorized as an RTO since October 1, 2004. *Sw. Power Pool, Inc.*, 109 F.E.R.C. ¶ 61,009 (2004), *order on reh'g*, 110 F.E.R.C. ¶ 61,137 (2005).

485. CAISO is an ISO but not an RTO. *See generally supra* note 144 and accompanying text.

486. ERCOT is not an RTO since it is non-jurisdictional to FERC. *See generally supra* note 162 and accompanying text.

487. Donald F. Santa Jr., *California's Power Crisis: Catalyst for National Reform?* PUB. UTIL. REP., Dec. 1, 2000, at 18, available at <http://www.pur.com/pubs/3629.cfm> (noting that Virginia is among the states having this requirement).

488. Such examples include Carolina Power & Light Company (CPL), Duke Energy Corporation, and South Carolina Electric & Gas Company (collectively, the GridSouth Companies or GridSouth) in Docket No. RT01-74-000; Florida Power & Light Company, Florida Power Corporation and Tampa Electric Company, (collectively, the GridFlorida Companies or GridFlorida) in Docket No. RT01-67-000; and, Southern Company Services, Inc., in Docket No. RT01-77-000. The first time that the Commission adopted the concept of a for-profit RTO was in 1999, acting upon a petition filed by Entergy, where the Commission said that passive ownership of a transmission entity by a generating company or market participant could meet the ISO principles of Order No. 888 as long as that entity is truly independent of the market participant. This sort of entity became known in the industry as a "transco." The first "for profit" solely wires company was a First Energy subsidiary (First Energy divested its transmission facilities to a subsidiary). This later became known as an ITC (lines only company).

489. *Mich. Elec. Transmission Co., LLC*, 105 F.E.R.C. ¶ 61,214 (2003); *ITC Holdings, Inc.*, 102 F.E.R.C. ¶ 61,182 (2003), *reh'g denied*, 104 F.E.R.C. ¶ 61,033 (2003); *Proposed Pricing Policy for Efficient Operation and Expansion of Transmission Grid*, 102 F.E.R.C. ¶ 61,032 (2003).

490. ATC combines the transmission assets of several utilities operating in Michigan's Upper Peninsula and part of northern Illinois, following the divestiture of five IOUs and more than 20 municipal entities and cooperatives. It started operations in 2001 and now operates about 9,000 miles of transmission lines and associated substations. All of the former transmission owners who divested their assets maintain shares in ATC, and are ATC's customers.

491. International owns the former transmission assets of Detroit Edison, about 2,700 miles of transmission lines and associated substations. The assets are owned directly by a partnership not affiliated with any transmission owners or market participants. Detroit Edison is International's main customer. International also conducted an IPO recently, offering 49.90% of its common stock to the general public. No market participant may acquire more than 5% of its stock. The ITC has also transferred most operational control to the Midwest ISO except that in this situation, it retained various duties that are local in character. FERC found that the ITC met the independence requirement as it was not affiliated or controlled by transmission owners or other

managed by National Grid America, (a British owned transmission utility and owner of transmission assets in the Northeast) also operated the transmission assets of several utilities in the Midwest, but recently closed operations, as some of the utilities did not realize anticipated benefits.⁴⁹³ Lastly, attempts to develop another ITC, TransLINK, failed after several years of negotiations. TransLINK envisioned the divestiture of transmission assets by various utilities in the Midwest (including MidAmerican, Xcel Energy) which would retain an interest in the organization (like ATC), and would have been managed by a separate Corporate Manager.

For the operational ITCs, there appear to be two models: (1) where the FERC allows the ITC to retain some designated responsibilities over its transmission system, and making a finding that the ITC meets the FERC's requirements of independence from market participants (i.e., Trans-Elect, International), and (2) where all operational control shifts to the RTO and thus there is no need to make a finding of independence, and the market participants are allowed to continue to hold interests in the ITC (i.e., ATC).

The ITC model appears to have had some successes in the Midwest, especially with International. However, supporters of the ITC model criticize the current Commission transmission policies, arguing that they are too restrictive, and do not allow ITCs to fully develop and achieve the synergies envisioned. One such supporter, National Grid, advocates the creation of ITCs that have more functions and responsibilities⁴⁹⁴ and cover a larger geographic area than currently envisioned for ITCs; it proposes diminishing the role of the RTO model and corresponding expansion of the ITCs role.⁴⁹⁵ In a recently issued *White Paper*, National Grid argues that ITCs need to be given more authority to take over many of the RTO functions to allow them to capitalize on their investments and expertise. It advocates for ITC operations over an expanded regional basis to maximize the performance of the transmission system. National Grid bases its view in part on its alleged success in England, where it owns the entire transmission system.

3. Current Trends: A New Kid on the Block

Recently, there is a new kid on the transmission grid: a type of entity first proposed by Entergy Corporation (Entergy) and known either as an Independent

market participants.

492. Trans-Elect owns the former transmission assets of Consumers Energy in the Midwest, which it acquired in May 2002. It owns all of the transmission assets through a holding company system, the upstream owner being Trans-Elect, an owner and operator of transmission systems in other regions of the United States and Canada and operates a transmission system comprised of 5,400 miles of lines and associated substations. Recently, Trans-Elect conducted an IPO, offering its stock to the public. The IPO restricted any market participant from acquiring more than 5% interest in the holding company. None of the managing companies or owners of Trans-Elect are associated with market participants in the region.

493. Ameren, for example, has stated that the level of operational efficiencies achieved through the Midwest ISO were at least the same or higher than the ones thorough GridAmerica. *See e.g.*, Ameren Corp., Current Report (Form 8-K), at 2 (Apr. 7, 2005). National Grid closed its doors in November 2005. In April 2005, GridAmerica Companies indicated that they would withdraw from GridAmerica, stating that they instead would participate in the Midwest ISO and be subject to the Midwest ISO Agreement. *Midwest Independent Transmission System, Inc.*, 113 F.E.R.C. ¶ 61,096 (2005).

494. National Grid advocates an ITC should have most operational control, including: real-time operations of the system, congestion management, transmission planning, asset management and access day-ahead and real-time bid data.

495. NAT'L GRID, TRANSMISSION: THE CRITICAL LINK (2005), available at http://www.nationalgridus.com/non_html/transmission_critical_link.pdf.

Coordinator of Transmission (ICT) or Transmission Services Coordinator (TSC). Entergy's newly Commission-approved⁴⁹⁶ proposal involves hiring an independent company—the Southwest Power Pool in Entergy's case to oversee its grid system as a way of complying with the FERC's open access requirements for transmission; the ICT would not be an RTO. Afraid of rising costs and of losing control over its transmission systems, and possibly jeopardizing reliability for its ratepayers, Entergy has refused to join an RTO.⁴⁹⁷ Under Entergy's proposal, the ICT's main functions would include granting transmission requests and organizing day-ahead markets,⁴⁹⁸ but not operating more intricate and controversial market functions such as running Day 2 markets, congestion management or establishment of firm transmission rights.⁴⁹⁹ The utility transmission provider (i.e., Entergy) would maintain ownership and operational control but would have to follow the directives of the ICT as to the functions described above. Other utilities have followed Entergy's blueprint; for example, in July, 2005, North Carolina-based Duke Power Corporation (Duke Power)⁵⁰⁰ and Iowa-based MidAmerican Energy Company (MidAmerican) filed ICT applications with the FERC to allow them to enter into contracts with ICTs for their systems.⁵⁰¹ MidAmerican believes that other utilities to the west of its control area may decide to use ICTs to provide similar functions for their respective systems, leading to the development of regional transmission services for the west, and enhanced regional reliability and planning processes.⁵⁰²

Along the same lines, on October 7, 2005, LG&E Energy LLC (LG&E) filed a proposal to withdraw from the MISO and hire SPP as an ICT to act as tariff administrator⁵⁰³ and TVA as their Reliability Coordinator to provide

496. See *Entergy Services, Inc.*, 110 F.E.R.C. ¶ 61,295 (2005), *order on clarification*, 111 F.E.R.C. ¶ 61,222 (2005) (finding that the proposed ICT may be just and reasonable with certain modifications and enhanced functions for the ICT, and would allow the ICT on a two-year experimental basis). Entergy made a section 205 filing in Docket No. ER05-1065-000, detailing the enhanced functions that the ICT will perform. Letter from Kimberly H. Despeaux, Assoc. Gen. Counsel, Entergy Services, Inc., to the Honorable Magalie Roman Salas, Sec'y, Fed. Energy Regulatory Comm'n (May 27, 2005) (transmittal letter regarding proposed revision to Entergy's Open Access Transmission Tariff, Docket No. ER05-1065). The Commission is in the process of reviewing the specifics of Entergy's proposal.

497. See e.g., Jeff Beattie, *Transmission Transition: Move Over RTO, Here Comes ICT*, *THE ENERGY DAILY*, Oct. 27, 2005.

498. The ITC would perform the following functions: approve transmission service requests, calculate total transfer capability and available transmission capacity, approve or deny NERC e-tags, receive and process generation interconnection request, manage the generator interconnection queue, perform transmission and generator interconnection feasibility and system impact functions, interpret the OATT provisions, have oversight and review authority over balancing authority functions, interchange and schedule checkouts, coordinate the expansion planning process, prepare the system facilities agreements.

499. William Scherman, an attorney with Skadden, Arns, Slate, Meagher & Flom LLP, representing Entergy, said the ICT model makes progress on a major goal of electricity restructuring, namely "shifting risk from utility customers to the market." Jeff Beattie, *Transmission Transition: Move Over RTO, Here Comes ICT*, *THE ENERGY DAILY*, Oct. 27, 2005.

500. Letter from Steven J. Ross, Steptoe & Johnson, to the Honorable Magalie Roman Salas, Sec'y, Fed. Energy Regulatory Comm'n (July 22, 2005) (transmittal letter regarding proposed revision to Open Access Transmission Tariff, Docket No. ER05-1236) [hereinafter *Duke Power Proposal*]. In its proposal, Duke Power requests that the Commission approve an operational agreement between the ICT and the utility, alleging that "the agreement [would] not impinge on the [ITC's] ability to perform its functions independently." *Id.* at 12. Under that agreement, all the ICT functions would be performed by employees or agents of the Midwest ISO. *Duke Power Proposal*, *supra*.

501. Letter from Steven J. Ross, Steptoe & Johnson, to the Honorable Magalie Roman Salas, Sec'y, Fed. Energy Regulatory Comm'n (June 22, 2005) (transmittal letter regarding proposal, Docket No. ER05-1235).

502. *Id.* at 12. To date, MidAmerican has not named an entity to act as its ITC/TSC, but has plans to conduct an RFP.

503. The functions proposed for the LG&E ICT are similar to those proposed by Entergy, Duke Power

security coordination services and oversee the transmission planning functions. LG&E states that the synergy of the ICT and Reliability Coordinator would lower the costs of operation for LG&E, while maintaining the Commission's objectives of non-discriminatory open access to the transmission service.⁵⁰⁴

Another RTO-model deviation has been made by Grid West, which recently announced it will sell transmission service under an OATT, but that it does not intend to create an Order No. 2000 RTO. Grid West voted to restructure without the participation of Bonneville Power Association. Its proposal aims to provide protections against discrimination, and economic efficiencies and reliability improvements superior to those provided under Order No. 888, but it would not meet all of the requirements of Order No. 2000. It is unclear yet what form of organization Grid West will use.⁵⁰⁵

A very recent development that may have a significant effect on the choice of organizational structure for transmission organizations, although it is not yet clear what this effect will be, is the Commission's effort to implement the EPAct 2005 requirement that the Commission "develop incentive-based rate treatments for transmission of electric energy in interstate commerce."⁵⁰⁶ As stated by the Commission:

To address the need for new transmission infrastructure and to encourage necessary investment, the new [s]ection 219 [of the FPA] specifically charges the Commission with the responsibility to establish, by rule, incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce that:

1. promote reliable and economically efficient transmission and generation of electricity by promoting capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce, regardless of the ownership of the facilities;
2. provide a return on equity that attracts new investment in transmission facilities (including related transmission technologies);
3. encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities; and
4. allow the recovery of all prudently incurred costs necessary to comply with mandatory reliability standards established pursuant to [s]ection 215 of the FPA, and all prudently-incurred costs related to transmission infrastructure development, pursuant to section [2]16 of the FPA (transmission national interest corridors).⁵⁰⁷

and MidAmerican except for the functions to be performed by the reliability coordinator.

504. See Louisville Transmittal Letter, *supra* note 140, at 4.

505. On November 18, 2005, Grid West announced that "Idaho Power Company, NorthWestern Energy, PacifiCorp (Utah Power and Pacific Power), Portland General Electric Company, Sierra Pacific Power Company, Avista Corporation, and British Columbia Transmission Corporation presented their vision and plans to continue development of a reconfigured Grid West proposal that includes their transmission facilities. On November 1, the Bonneville Power Administration (BPA) and Puget Sound Energy elected to withdraw from the Grid West development process." Press Release, Grid West, Grid West Gains Critical Mass to Move Forward (Nov. 18, 2005), available at http://www.rtwest.com/Doc/GWNewsRelease_Nov182005.pdf.

506. Press Release, Commission Proposes Transmission Pricing Reforms to Increase Power Grid Investment (Nov. 17, 2005), available at <http://www.ferc.gov/press-room/press-releases/2005/2005-4/11-17-05-E-2.pdf>.

507. *Promoting Transmission Investment through Pricing Reform*, F.E.R.C. STATS & REGS. ¶ 32,593 at P

Among the incentives available to all jurisdictional public utilities proposed in that NOPR are provisions which would provide a return on equity that would attract new investment in transmission facilities, allow the recovery of prudently incurred construction work in progress and prudently incurred pre-commercial operations costs, allow use of a hypothetical capital structure, accelerated depreciation, and deferred cost recovery, and allow recovery of costs of abandoned facilities.⁵⁰⁸ Among the incentives proposed to be available for Transco formation and investment are provisions for a return on equity based incentive and recovery of accumulated deferred income taxes. The NOPR also proposes a return on equity incentive for joining a transmission organization, approval of all prudently incurred costs associated with reliability standards and transmission infrastructure development, certain reporting requirements, the removal of certain existing regulations concerning innovative transmission rate treatments for RTOs, single issue ratemaking applicable only to the new transmission projects, and acquisition premiums for Transco creation. The Commission also seeks comments on performance-based ratemaking, the role of public power, and how to encourage the use of advanced technology in new transmission projects.

In summary, it remains unclear which direction utilities will take in forming transmission organizations. As is clear from the above discussion, there are various views concerning the costs and benefits of both existing non-profit RTOs and for-profit transcos. In the midst of this inquiry, the industry continues to experiment with new forms of transmission organization that would provide non-discriminatory open access to all market participants.

I. State Participation in RTO Operations: Regional State Committees

The Commission introduced the Regional State Committee (RSC) in its 2002 Standard Market Design Notice of Proposed Rulemaking. The FERC acknowledged that “[s]tates have an important role in the process of creating and sustaining an efficient competitive wholesale market for electricity[.]” and proposed to establish a formal role for state representatives to participate in the decision-making process of RTOs.⁵⁰⁹ It envisioned establishing RSCs that would provide the RTO, “market participants[,] and the Commission with a consensus view from states in the area.”⁵¹⁰ The Commission specified that the RSC may work with the RTO to explore “regional solutions to issues that may fall under federal, state, or shared jurisdiction,” such as resource adequacy standards, transmission planning and expansion, market monitoring and other matters.⁵¹¹

While RSCs currently are undeveloped,⁵¹² MISO and SPP have established RSCs in their regions. In addition, ISO-NE is working toward creating an RSC in an ongoing proceeding before the FERC.

3, 70 Fed. Reg. 71,409 (2005).

508. SMD NOPR, *supra* note 1.

509. *Id.* at P 551.

510. SMD NOPR, *supra* note 1, at P 551.

511. *Id.* at P 554.

512. For a summary of information on Regional State Committee development in existing and proposed RTOs and ISOs, *see* Examples of Stakeholder, *supra* note 396.

1. ISO-NE

On September 8, 2003, a proposal to create a Regional State Committee was approved by the New England Governors. On October 31, 2003, ISO-NE and seven New England Transmission Owners proposed, in the context of the formation of an RTO, that an RSC be a part of the structure of ISO-NE. On March 24, 2004, the Commission approved the ISO-NE proposal subject to the fulfillment of certain requirements.⁵¹³

On June 25, 2004, the governors of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont (Governors) filed a Joint Petition for Declaratory Order to Form a New England RSC.⁵¹⁴ The Governors proposed

to form a non-profit corporation, the New England States Committee on Electricity (NESCOE) that [would] serve as the . . . region's [RSC]. NESCOE [would] focus on developing and making policy recommendations related to resource adequacy and systems planning, and investigating and reporting to the New England Governors on policy questions concerning the possibility of creating a regional authority for siting of interstate transmission facilities.⁵¹⁵

In addition, the Governors proposed that in the future, NESCOE "could address issues such as security, fuel diversity, conservation, and the environmental impacts of power generation."⁵¹⁶ However, "the scope of NESCOE's responsibility [would] be expanded . . . only through a unanimous vote of its members."⁵¹⁷ The Governors filed the petition as an informational filing in light of the Commission's references to a RSC in its order in *ISO New England Inc.*⁵¹⁸

[The Governors] state that NESCOE must also have the ability to initiate the Commission's consideration of policy changes if ISO-NE or the New England [Transmission Owners] do not take action within their respective spheres. [They] state that [in] instances in which NESCOE submits a Majority Determination to change or add to market rules or tariffs necessary to carry out a policy on a matter within the scope of its responsibility, if ISO-NE or the New England [Transmission Owners] do not file a proposal at the Commission within a reasonable time seeking to implement NESCOE's determination, NESCOE would file its determination under [s]ection 206 of the Federal Power Act.⁵¹⁹

In an order issued on July 7, 2005, the Commission deferred acting on the petition for declaratory order.⁵²⁰ Because a major concern of protesters was that many of the Governors' controversial proposals had not been vetted through a stakeholder process, the FERC encouraged the Governors to undertake consultations with other stakeholders to address certain issues raised in the proceeding. It directed the Governors to file a compliance filing in this proceeding following further discussion at the stakeholder level. Concerning initiation of proceedings under the FPA, the Commission noted that in its March 2004 order approving an RTO organization, the provisions agreed to by the parties in the RTO proceeding included requirements for consultation with the

513. *ISO New England Inc.*, 106 F.E.R.C. ¶ 61,280 (2004), *order on reh'g*, 109 F.E.R.C. ¶ 61,147 (2004).

514. Petition for Exemption from Fees Pursuant to 18 C.F.R. § 381.108, FERC Docket No. EL04-112-0000 (June 25, 2004).

515. *The Governors of: Connecticut, Maine Massachusetts, New Hampshire, Rhode Island, Vermont*, 112 F.E.R.C. ¶ 61,049 at P 1 (2005).

516. *Id.* at P 8.

517. 112 F.E.R.C. ¶ 61,049 at P 8.

518. *ISO New England Inc.*, 106 FERC ¶ 61,280 (2004).

519. *Id.* at P 13.

520. 112 F.E.R.C. ¶ 61,049 at P 2.

RSC in advance of making a section 205 filing.⁵²¹

On October 21, 2005, and January 19, 2006, ISO-NE and the Governors filed status reports concerning stakeholder discussions regarding the potential establishment of an RSE for New England. According to the reports, representatives of each of NEPOOL's voting sectors and representatives of the ISO have met to negotiate the term sheet outlining the proposed formation and operation of NESCOE, and anticipate that a final proposed term sheet will be submitted to the Participants Committee for a vote. A final Commission order in this proceeding has not yet been issued.

2. Midwest ISO

In MISO, an RSC called the Organization of MISO States (OMS) was established on June 11, 2003. OMS was formed "as a non-profit, self-governing organization of representatives from each state with regulatory jurisdiction over entities participating in the MISO"⁵²²

The purpose of the OMS is to coordinate regulatory oversight among its state members, make recommendations to MISO, the MISO Board of Directors, the FERC, other relevant government entities, and state commissions as appropriate, and intervene in proceedings before the FERC and in related judicial proceedings to express the positions of the OMS.⁵²³

OMS in March 2005 approved a MISO Advisory Process that delineates the role of State Commission representatives. Under the Advisory Process,

[t]he Advisory Committee of the Midwest ISO (MISO) makes recommendations and provides advice to MISO management and the Board of Directors. From the Transmission Owners Agreement, which has been approved at FERC, it is clear that it is advice, and there is no obligation that the advice be taken nor is any action taken in the Advisory Committee process binding on any state commission.⁵²⁴

"Lead states" are expected to undertake responsibilities in several areas, such as negotiations, participating in MISO Subcommittee and Working Group meetings, and serving as liaison to MISO Staff and Stakeholder Groups.⁵²⁵

Under the OMS bylaws, the OMS Vice-President serves as one of the Advisory Committee members, with "lead state" responsibility.

3. Southwest Power Pool

SPP's RSC was established on April 26, 2004. The RSC provides collective state regulatory agency input on matters of regional importance related to the development and operation of SPP's bulk electric transmission. It is comprised of retail regulatory commissioners from agencies in Arkansas, Kansas, Louisiana, Missouri, New Mexico, Oklahoma and Texas. The RSC provides input on many matters, including: whether participant funding will be used for transmission enhancements; whether license plate or postage stamp

521. *The Governors of: Connecticut, Maine Massachusetts, New Hampshire, Rhode Island, Vermont*, 112 F.E.R.C. ¶ 61,049 at P 25 (2005).

522. Motion of the Organization of MISO States for Intervention Out-Of-Time, FERC Docket Nos. EL02-111-004 and EL03-212-002 (Apr. 12, 2004).

523. *Id.*

524. ORGANIZATION OF MISO STATES, MISO ADVISORY PROCESS—ROLE OF STATE COMMISSION REPRESENTATIVES (2005), available at <http://www.misostates.org/MISOAdvisoryProcessAdoptedMar2005.pdf>.

525. *Id.*

rates will be used for the regional access charge; determination of FTR allocations; determination of the approach for resource adequacy across the entire region; and determination of the role of transmission owners in proposing transmission upgrades in the regional planning process.⁵²⁶ In a February 10, 2004 order (February 10 Order), the FERC supported the creation of the RSC, noting that a “representative RSC will benefit SPP and market participants by instituting a partnership between the FERC and State commissions through which regional issues can be addressed.”⁵²⁷

4. Section 205 Filing Rights

The emergence of RSCs has sparked some debate concerning section 205 filing rights. In the February 10 Order granting RTO status, the FERC directed SPP to re-file a new RSC proposal to modify its bylaws that incorporate the following functions:

The RSC should have primary responsibility for determining regional proposals and the transition process in the following areas: (1) whether and to what extent participant funding would be used for transmission enhancements; (2) whether license plate or postage stamp rates will be used for the regional access charge; (3) FTR allocation where a locational price methodology is used; and (4) the transition mechanism to be used to assure that existing firm customers receive FTRs equivalent to the customers’ existing firm rights. *If the RSC reaches a decision on the methodology that would be used, SPP would file this methodology pursuant to [s]ection 205 of the FPA. SPP can also file its own proposal pursuant to [s]ection 205.*⁵²⁸

Commissioner Kelliher wrote a separate concurrence in the February 10 Order, in which he noted that SPP’s filing raised an important legal question, “namely whether a Regional State Committee can require a Regional Transmission Organization to make a filing to the Commission.”⁵²⁹ Commissioner Kelliher cited to *Commonwealth of Massachusetts v. United States*,⁵³⁰ in which the Court considered whether a State could require a public utility under the Federal Power Act to make a filing to the Commission. It held that a State cannot compel such a filing. Commissioner Kelliher pointed out that under the Federal Power Act, an RTO is a “public utility,” and commented: “I doubt that the Federal courts would find what is impermissible for a State to do individually is permissible if a group of States act collectively.”⁵³¹

On rehearing, the FERC rejected arguments that the RSC would infringe on SPP’s own section 205 filing rights. The FERC underscored that SPP agreed to file certain regional proposals that may be developed by the RSC, and that in addition to RSC proposals, SPP may file its own proposals. Finally, the FERC noted that its “order on SPP’s compliance filing to the February 10 Order, we accepted proposed language in section 7.2 of SPP’s Bylaws, which provides that no RSC proposal ‘shall prohibit SPP from filing its own related proposal(s)

526. For a full description of the purpose of the RSC, see SOUTHWEST POWER POOL, REGIONAL STATE COMMITTEE BYLAWS Article I.2 (2005).

527. *Sw. Power Pool, Inc.*, 106 F.E.R.C. ¶ 61,110 at P 218 (2004), *order on reh’g*, 109 F.E.R.C. ¶ 61,010 (2004).

528. 106 F.E.R.C. ¶ 61,110 at P 219 (emphasis added).

529. *Id.* (concurring opinion of Commissioner Kelliher).

530. *Commonwealth of Massachusetts v. United States*, 729 F.2d 886 (1st Cir. 1984).

531. 106 F.E.R.C. ¶ 61,110 at P 2.

pursuant to [S]ection 205.”⁵³²

J. Locational Marginal Pricing

Limitations in the transmission grid in the short run may constrain long-distance movement of power and thereby impose a higher marginal cost in certain locations. As Dr. Hogan stated:

In the simplest case, power will flow over the transmission line from the low cost to the high cost location. If this line has a limit, then in periods of high demand not all the power that could be generated in the low cost region could be used, and some of the cheap plants would be “constrained off.” In this case, the demand would be met by higher cost plants that, absent the constraint, would not run, but due to transmission congestion would be “constrained on.” The marginal cost in the two locations differs because of transmission congestion.⁵³³

When congestion exists, the difference in energy prices to transmission users is a price signal that reflects the marginal cost of economic dispatch of resources necessary to accommodate the transmission service. Those who place a higher value on the transmission capacity and the value of the ultimate delivered electricity will be willing to pay higher transmission usage charges.⁵³⁴

Under locational marginal pricing (LMP),

the price to transmit energy between any receipt . . . and delivery point reflects the marginal cost (including the marginal opportunity cost) of such transmission service, and the price of energy at each location reflects the marginal cost (as reflected in participants’ bids) of producing energy and delivering it to that location.⁵³⁵

LMP is designed to allow more efficient management of the transmission grid by providing price signals indicating where investment in generation and transmission is needed to improve grid operations.⁵³⁶ Because transmission usage charges under LMP will vary based on the price of relieving congestion at each node, congestion contracts (a system of financial rights entitling the holder to the congestion revenues for a particular quantity of power between two locations) are used to enable transmission customers to define a hedge for differences in locational prices.

Following PJM’s adoption of LMP in 1998, this form of congestion pricing has developed a steady and consistent following among RTOs and ISOs as well as the Commission. At present, PJM, NYISO, the MISO, CAISO, and ISO-NE all use LMP and some form of FTRs to manage congestion on their respective systems, and SPP and ERCOT are scheduled to employ LMP in 2006 and 2008–2009, respectively.⁵³⁷ Thus, by 2010 every regional market in the country will be under an LMP regime with respect to congestion management. Moreover, the Commission has assiduously demonstrated its predisposition towards locational

532. 109 F.E.R.C. ¶ 61,010 at P 93 (citing *Sw. Power Pool, Inc.*, 106 F.E.R.C. ¶ 61,110 at P 218 (2004), *order on reh’g*, 109 F.E.R.C. ¶ 61,010 (2004)).

533. WILLIAM H. HOGAN, HARVARD UNIV., *COMPETITIVE ELECTRICITY MARKET DESIGN: A WHOLESALE PRIMER* 6 (Dec. 17, 1998), available at <http://ksghome.harvard.edu/~whogan/empr1298.pdf>.

534. SMD NOPR, *supra* note 1, at P 207.

535. *Id.* at P 203. It is widely accepted principle of economics that markets work efficiently when prices reflect marginal costs. See ALFRED E. KAHN, *THE ECONOMICS OF REGULATION: PRINCIPLES AND INSTITUTIONS* 63–70 (MIT Press 1988) (1971).

536. SMD NOPR, *supra* note 1.

537. THE ISO/RTO COUNCIL, *THE VALUE OF INDEPENDENT REGIONAL GRID OPERATORS* 38 (2005), available at <http://www.spp.org/Publications/IRC-ValueIndRegGridOps-11-2005.pdf>.

pricing.⁵³⁸

Notwithstanding the pervasiveness of LMP throughout RTO's and ISOs across the country and the Commission's palpable bias thereto, LMP has not been without its share of critics. For example, the American Public Power Association (APPA) was quite outspoken against LMP, *inter alia*, during the Commission's now-defunct, SMD initiative. According to APPA, public power entities are deleteriously affected by LMP in the following manner: there are insufficient FTRs available to hedge existing (and long term) firm transmission arrangements;⁵³⁹ the LMP/FTR system alone does not ensure construction of adequate transmission infrastructure—that is, “a timely and effective transmission planning and construction regime is” also needed;⁵⁴⁰ and LMP cannot work in areas with unchecked local market power.⁵⁴¹

Perceived infirmities regarding LMP were one of the many issues at the fore when the Commission established a non-adversarial, fact-finding proceeding “concerning transmission congestion on the portion of the power grid on the Delmarva Peninsula operated by PJM.”⁵⁴² The impetus for this proceeding was a number of protests by PJM customers (such as Old Dominion Electric Cooperative) alleging that transmission congestion, and the resulting increased costs of delivered energy, were a persistent problem on the Delmarva Peninsula that needed Commission action to be resolved. In fact, some parties alleged that the high congestion costs on the Delmarva Peninsula were caused or exacerbated by LMP. However, as the ALJ found in her proposed findings of fact and recommendations: “Congestion is not caused or increased by LMP markets, but its existence and its costs are revealed by LMP prices.”⁵⁴³

Because transmission usage charges under LMP will vary based on the price of relieving congestion at each node, this form of congestion management can result in volatile price fluctuations—which can be particularly inimical to

538. See, e.g., *Midwest Indep. Sys. Operator, Inc.*, 102 F.E.R.C. ¶ 61,196 at P 31 (2003) (“Locational marginal pricing is supported by the Commission as a congestion management system because it makes transparent what the true marginal cost of congestion is to transmission customers. All other . . . price-based methods suppress that cost through some type of averaging (e.g., zonal pricing), thus distorting the short-term price signal and possibly also the location of new generation and transmission assets”); WHITE PAPER, *supra* note 89, at app. A, at 8 (“The Commission’s preferred approach to congestion management is through location pricing.”); *New England Power Pool*, 100 F.E.R.C. ¶ 61,287 at P 101 (2002). (“The Commission believes that location is an important aspect of ensuring optimal investment in resources”); SMD NOPR, *supra* note 1, at P 210 (“LMP allocates scarce transmission capacity to those who value it most and relies on an incentive system (i.e., it assigns congestion costs to the transactions that cause the congestion) that encourages market participants to buy and sell power in a manner that is consistent with the reliable operation of the system.”); Order No. 2000, *supra* note 5, at p. 31,127 (“[M]arkets that are based on locational marginal pricing and financial rights for firm transmission service appear to provide a sound framework for efficient congestion management.”).

539. RESTRUCTURING AT THE CROSSROADS, *supra* note 409, at 7–8. The arguments raised herein regarding LMP are (for the most part) a recapitulation of those that the APPA raised in the myriad comments they submitted in the Commission’s SMD proceeding.

540. *Id.* at 13.

541. RESTRUCTURING AT THE CROSSROADS, *supra* note 409.

542. *Transmission Congestion on the Delmarva Peninsula*, 103 F.E.R.C. ¶ 61,163 at P 1 (2003).

543. *Transmission Congestion on the Delmarva Peninsula*, 105 F.E.R.C. ¶ 63,004 at P 141 (2003). As it turned out, a significant number of the issues raised in this proceeding ended being addressed in separate dockets. See, e.g., *PJM Interconnection, L.L.C.*, 108 F.E.R.C. ¶ 61,196 (2004) (PJM post-contingency dispatch proceeding); *PJM Interconnection, L.L.C.*, 107 F.E.R.C. ¶ 61,053 (2004), *order on reh’g*, 110 F.E.R.C. ¶ 61,053 (2005) (PJM proposal to establish a competitive auction to address long-term scarcity); *PJM Interconnection, L.L.C.*, 103 F.E.R.C. ¶ 61,167 (2003) (PJM load-response program). As a result, the Commission terminated this proceeding on April 15, 2005 without issuing a final order on the merits. *PJM Interconnection, L.L.C.*, 111 F.E.R.C. ¶ 61,044 (2005).

those with insufficient FTRs.⁵⁴⁴ This has led some to explore the viability of alternate methods of congestion management pricing—such as flowgate rights.⁵⁴⁵ One of the strongest arguments in favor of flow-gate rights is that they are inherently options with “bounded down-side risk from price reversals as compared to FTRs, which are described as inherently obligations with significant down-side risk.”⁵⁴⁶ However, because there are many potential constraints, transmission customers would have to obtain numerous flowgate rights—which could prove to be an inordinately complex process given the number of possible constraints and transmission lines that would need to be considered for each transaction. This could very well explain why neither flowgate rights, nor any other system of decentralized congestion management, has engendered much support to date.

K. *New England Cold Snap*

On January 14–16, 2004, the New England region suffered “extreme cold weather conditions . . . that produced record demand and threatened the reliability of the electric and natural gas systems in the region”⁵⁴⁷ In response to that cold snap event, NEPOOL adopted a new operating procedure and revised an existing operating procedure “to address reliability needs and provide for market conditions during extreme cold weather forecasts.”⁵⁴⁸ In response to the Commission’s directives in an order issued on January 21, 2005,⁵⁴⁹ on January 28, 2005, ISO-NE and NEPOOL

jointly filed a new Appendix H to NEPOOL Market Rule 1. . . . Appendix H includes special provisions relating to the dispatch and operation of the New England bulk power system during extreme cold weather conditions. . . . Appendix H (or Cold Weather Procedures) incorporates all of the provisions of NEPOOL’s Operating Procedures 20 (OP20) and the relevant revised provisions of Operating Procedure 5 (OP5).⁵⁵⁰

ISO-NE introduced these Cold Weather Provisions as a temporary measure while stakeholders develop permanent procedures, and will terminate on April 15, 2006.⁵⁵¹

The Commission accepted ISO-NE’s revisions for filing and set them for

544. On November 28, 2005, the Commission issued a NOPR, wherein it proposed, pursuant to the requirements of the Transmission Infrastructure Investment provisions in section 1241 of the Energy Policy Act of 2005, to amend its regulations by establishing incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion. However, this NOPR seeks to relieve congestion on the nation’s transmission grid solely by fomenting investment in transmission infrastructure, not through congestion-management pricing. Notice of Proposed Rulemaking, *Promoting Transmission Investment Through Pricing Reform*, F.E.R.C. STATS & REGS. ¶ 32,593, 70 Fed. Reg. 71,409 (2005).

545. “A flowgate is a particular transmission facility or group of facilities (e.g., an interface). A flowgate right specifies a portion of the transmission capacity over that flowgate in a specified direction. A flowgate right entitles the holder to the day-ahead congestion revenues associated with the specified power flows over the flowgate in the specified direction.” SMD NOPR, *supra* note 1, at P 246.

546. WILLIAM W. HOGAN, HARVARD UNIV., FLOWGATE RIGHTS AND WRONGS 17 (Aug. 20, 2000) available at <http://www.ksg.harvard.edu/hepg/flowgate/HoganFlowgate.pdf>.

547. *ISO New England, Inc.*, 110 F.E.R.C. ¶ 61,202 at P 2 (2005).

548. *ISO New England, Inc.*, 110 F.E.R.C. ¶ 61,202 at P 2 (2005).

549. *ANP Funding I, LLC*, 110 F.E.R.C. ¶ 61,040 (2005).

550. 110 F.E.R.C. ¶ 61,202 at P 3.

551. *Id.* at P 6.

hearing and settlement judge procedures.⁵⁵² On September 8, 2005,⁵⁵³ ISO-NE and the settling parties filed an uncontested⁵⁵⁴ partial settlement agreement which was certified by an Administrative Law Judge on September 30, 2005.⁵⁵⁵ In an order issued on November 17, 2005, the Commission approved the partial settlement agreement.⁵⁵⁶ The Commission also directed ISO-NE “to file revised tariff sheets incorporating the Last Resort Requirement, as modified to delete the Best Efforts standard it proposed and insert the Good Utility Practice standard proposed by generators.”⁵⁵⁷

In a separate proceeding, on October 28, 2005, ISO-NE and the NEPOOL Participants Committee jointly filed an interim revision to Market Rule 1 to aid the ISO in implementing its Winter 2005/2006 Action Plan.⁵⁵⁸ Several parties filed comments on the filing, and the Commission on November 30, 2005 issued an order conditionally accepting ISO-NE’s proposed tariff revisions, to become effective December 1, 2005, subject to further Commission action.⁵⁵⁹ Requests for rehearing of the Commission’s order are pending before the Commission.

Finally, on November 29, 2005, ISO-NE filed its Supplemental Winter Package, and on December 12, 2005 it filed an additional interim revision to Market Rule 1⁵⁶⁰ “to aid ISO-NE in implementing its Winter 2005/2006 Action Plan.”⁵⁶¹ The Supplemental Winter Package Filing addresses compensation for costs incurred by Resources when postured.⁵⁶² The Commission in December, 2005 issued letter orders accepting the ISO’s tariff filings amending Market Rule 1 for Winter 2006/2006.⁵⁶³

L. August 14th Blackout and Electricity Modernization Act of 2005

The August 14, 2003 blackout in the Northeast highlighted the shortcomings of the current voluntary approach to ensuring electric transmission system reliability.⁵⁶⁴ The Final Report on the August 14, 2003 Blackout In the

552. 110 F.E.R.C. ¶ 61,202 at P 31.

553. Letter from ISO New England Inc., to the Honorable Magalie Roman Salas, Sec’y, Fed. Energy Regulatory Comm’n (Sept. 8, 2005) (transmittal letter regarding Partial Settlement Agreement and Request for Expedite Action, Docket No. ER05-508-000).

554. Although the settlement was uncontested, the Connecticut Attorney General filed a late intervention, arguing that the settlement does not go “far enough in preventing gas-fired utilities in emergency cold weather conditions from selling their gas stocks on the spot market to reap windfall profits while ceasing to generate needed electricity” *ISO New England Inc.*, 112 F.E.R.C. ¶ 63,033 at n.1 (2005).

555. 112 F.E.R.C. ¶ 63,033.

556. *ISO New England, Inc.*, 113 F.E.R.C. ¶ 61,175 (2005).

557. *ISO New England, Inc.*, 113 F.E.R.C. ¶ 61,175 at P 1 (2005).

558. Letter from ISO New England Inc. and NEPOOL, to the Honorable Magalie Roman Salas, Sec’y, Fed. Energy Regulatory Comm’n (Oct. 28, 2005) (transmittal letter regarding Interim Amendments to Market Rule 1 for Winter 2005/2006, Docket No. ER06-89-000).

559. *ISO New England, Inc.*, 113 F.E.R.C. ¶ 61,220 at P 1 (2005). Requests for rehearing of that order are pending before the Commission.

560. ISO New England Open Access Transmission Tariff, Market Rule 1 – Standard Market Design, § III, FERC Electric Tariff No. 3, Original Sheet No. 7000 (effective Feb. 1, 2005).

561. Letter from ISO New England Inc., to the Honorable Magalie Roman Salas, Sec’y, Fed. Energy Regulatory Comm’n (Nov. 29, 2005) (transmittal letter regarding Additional Interim Amendments to Market Rule 1 for Winter 2005/2006 (“Supplemental Winter Package”), Docket No. ER06-252-000 (Nov. 29, 2005).

562. *ISO New England, Inc.*, 113 F.E.R.C. ¶ 61,304 at P. 1 (2005).

563. Consistent with the Market Rule 1 changes contained in the Winter Package Filing and the Supplemental Winter Package Filing, the proposed revision expired on March 31, 2006.

564. See U.S.-CANADA POWER SYSTEM OUTAGE TASK FORCE, FINAL REPORT ON THE AUGUST 14, 2003 BLACKOUT IN THE UNITED STATES AND CANADA: CAUSES AND RECOMMENDATIONS (2004) [hereinafter FINAL

United States and Canada identified the need for legislation to “make reliability standards mandatory and enforceable, with penalties for non-compliance.”⁵⁶⁵ It recommended that “[r]eliability standards should be developed by an independent, international electric reliability organization (ERO) with fair stakeholder representation in the selection of its directors and balanced decision-making in any ERO committee or subordinate organizational structure.”⁵⁶⁶ According to the Report, “[t]he need for additional attention to reliability is not necessarily at odds with increasing competition and the improved economic efficiency it brings to bulk power markets.”⁵⁶⁷

On August 8, 2005, President Bush signed the Electricity Modernization Act (EMAct) of 2005 (Title XII of the Energy Policy Act of 2005) into law. Subtitle A of the EMAct added a new section 215 to the FPA, which proposed the creation of an Electric Reliability Organization (ERO).⁵⁶⁸ In preparation for implementation, the FERC on August 3, 2005 had issued its “Principles For An Electric Reliability Organization That Can Function On An International Basis” (bilateral principles).⁵⁶⁹ The bilateral principles were intended to guide the establishment of a reliability organization that can function effectively in the United States and Canada. The principles included: governance of the ERO, membership, funding, remand, enforcement, audits, and regional entities. The FERC on September 1, 2005 issued a NOPR on “Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards.”⁵⁷⁰ A number of the bilateral principles were incorporated into the NOPR, and the Commission asked questions and sought comment on those principles.

The regulations proposed in the NOPR included the delegation of certain ERO authority to Regional Entities, including proposing reliability standards to the ERO, and enforcing the reliability standards.⁵⁷¹ The bilateral principles issued on August 3, 2005 provide that RTOs and ISOs should not become Regional Entities, and that the Regional Entities should be distinct from the operators of the system, such as RTOs and ISOs. However, in the NOPR, the FERC posed several questions, such as: Should the proposed rule mandate this? What are the enforcement implications of an RTO or ISO that is a Regional Entity? Are there ways for an RTO or ISO to adequately separate its enforcement function from its ownership, use or operation of the Bulk-Power System to fully ensure the independence of the enforcement unit?

BLACKOUT REPORT].

565. *Id.* at 140–42.

566. FINAL BLACKOUT REPORT, *supra* note 566, at 140. The report also recommended that the “FERC should not authorize a new RTO or ISO to become operational until the RTO or ISO has verified that all critical reliability capabilities will be functional upon commencement of RTO or ISO operations.” *Id.* at 147. According to the Report, “[t]he events of August 14 confirmed that MISO did not yet have all of the functional capabilities required to fulfill its responsibilities as reliability coordinator for the large area where the blackout within its footprint” occurred. FINAL BLACKOUT REPORT, *supra* note 566, at 147.

567. *Id.* at 140. See also William L. Massey, Robert S. Fleishman, & Mary J. Doyle, *Reliability-Based Competition in Wholesale Electricity: Legal and Policy Perspectives*, 25 ENERGY L.J. 319 (2004).

568. See Energy Policy Act of 2005 § 1211, Pub. L. No. 109-58, 119 Stat. 594 (to be codified at 16 U.S.C. § 824).

569. Principles For An Electric Reliability Organization That Can Function On An International Basis, FERC Docket No. RM05-30-000 (Aug. 3, 2005).

570. Notice of Proposed Rulemaking, *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, F.E.R.C. STATS & REGS. ¶ 32,587, 70 Fed. Reg. 35,117 (2005).

571. *Id.* at P 79.

Several RTOs and ISOs, as well as the ISO/RTO Council⁵⁷² (IRC) filed comments in response to the NOPR. While the “IRC support[ed] the development of clear and enforceable international reliability standards[,]” its comments sought to help the Commission ensure clearly defined roles for all entities charged with ensuring reliability, including the ERO, Regional Entities, RTOs/ISOs, and other control area operators.⁵⁷³ The IRC urged the Commission to ensure that roles are clearly defined to avoid creating confusing and potentially overlapping layers of regulation. According to IRC, the ERO’s and regional entities’ role should be to promulgate clear standards and administer consistent sanctions for violations of the standards, while the RTO’s and ISO’s role is to implement the standards in accordance with their approved tariffs and operating procedures.⁵⁷⁴ IRC compared this proposed delineation of roles to the division of responsibilities today among the North American Electric Reliability Council (NERC), the regional reliability councils and the ISO/RTOs.⁵⁷⁵

The IRC also identified a tension in the NOPR concerning issues associated with North American vs. regional standards and the interplay between approved tariff provisions and new reliability standards.⁵⁷⁶ IRC’s overall recommendations are summarized as follows:

- Ensure Clear, Internationally Applicable Standards
- Develop Non-Discriminatory Standards Adaptable to All Regions
- Clearly Define Roles by Differentiating between the ERO’s or Regional Entities’ Promulgation vs. System Operators/Planners’ Implementation of Standards Pursuant to Tariffs
- Provide Definitive Criteria for Determining Whether a Standard Is Just and Reasonable
- Where Justified, Individual Regions Should Be Authorized to Have Reliability Rules that Are More Stringent than, but Consistent with, ERO Standards.⁵⁷⁷

Several ISOs and RTOs joining the IRC filed separate supplemental comments. ERCOT filed separate comments and elected not to join IRC’s comments.

On February 3, 2006, the Commission issued final rules concerning certification of the ERO, and procedures for the establishment, approval, and enforcement of electric reliability standards.⁵⁷⁸ FERC Chairman Kelliher stated regarding the rules: “Under the Energy Policy Act, regional entities will propose regional standards or variances to the national reliability organization charged

572. The nine functioning RTOs and ISOs in North America formed the IRC in April 2003. The IRC is comprised of the Alberta Electric System Operator (AESO), CAISO, the Independent Electricity System Operator of Ontario (IESO), ISO-NE, MISO, NYISO, PJM, ERCOT, and SPP. The AESO and IESO are not subject to this Commission’s jurisdiction.

573. Comments of the ISO/RTO Council on Proposed Regulations, FERC Docket No. RM05-30-000 at 2 (Oct. 7, 2005) [hereinafter IRC Comments].

574. *Id.* at 3.

575. IRC Comments, *supra* note 575, at 3.

576. *Id.*

577. IRC Comments, *supra* note 575, at 15.

578. Order No. 672, *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, F.E.R.C. STATS. & REGS. ¶ 31,204 (2006), 71 Fed. Reg. 8662 (2006).

with standards development, the ERO, which can then propose to the Commission those regional standards that it has approved.”⁵⁷⁹ Chairman Kelliher noted that “Congress would not have provided for consideration of regional standards or variances if it had intended a ‘one size fits all’ approach.”⁵⁸⁰

M. Other Provisions of EPOA 2005 Affecting RTOs

1. Open Access by Unregulated Transmitting Utilities (FERC Lite)

Section 1231 of EPOA 2005 (Open Nondiscriminatory Access), requires unregulated utilities to provide transmission services at rates, and on terms and conditions, comparable to those that the utility applies to itself. However, nothing in that section authorizes the Commission to require an unregulated transmitting utility to transfer control or operational control of its transmitting facilities to a Transmission Organization⁵⁸¹ that is designated to provide nondiscriminatory transmission access.

2. Federal Utility Participation in RTOs

EPOA 2005 section 1232 authorizes, but does not require, federally owned utilities to participate in Transmission Organizations, which are defined to include ISOs and RTOs.⁵⁸² Thus, section 1232 gives federal power marketing agencies and Tennessee Valley Authority explicit statutory authority to participate in RTOs. EPOA 2005 states that an agreement to transfer control of all or part of a transmission system to an RTO shall include performance standards that ensure: (1) recovery of all of the costs and expenses of the Federal utility related to the transmission facilities that are the subject of the contract, agreement, or other arrangement; (2) consistency with existing contracts and third-party financing arrangements; and (3) consistency with the statutory obligations of the Federal utility. Such agreements shall also include provisions for monitoring and oversight of the RTO’s terms and conditions of the agreement, and a provision that allows the Federal utility to withdraw from the RTO.

VII. CONCLUSION

This article surveys many RTO and ISO developments that are at the forefront of electric industry policymaking at the Commission and in the

579. Statement, Fed. Energy Regulatory Comm’n, Statement of Chairman Joseph T. Kelliher on Electric Reliability Organization (ERO) (Feb. 2, 2006), available at <http://www.ferc.gov/press-room/statements/kelliher/2006/02-02-06-kelliher-E-1.asp>.

580. *Id.*

581. “The term ‘Transmission Organization’ has the meaning given the term in section 3 of the Federal Power Act (16 U.S.C. 796).” Energy Policy Act of 2005 § 1232(a)(4), Pub. L. No. 109-58, 119 Stat. 594 (to be codified at 42 U.S.C. § 16431). Under EPOA 2005, section 3 of the FPA was amended by defining the term “Transmission Organization,” which “means a Regional Transmission Organization, Independent System Operator, independent transmission provider, or other transmission organization finally approved by the Commission for the operation of transmission facilities.” Energy Policy Act of 2005 § 1291(b)(2), Pub. L. No. 109-58, 119 Stat. 594 (to be codified at 16 U.S.C. § 796).

582. See also MORGAN MEGUIRE LLC, ENERGY POLICY ACT OF 2005, KEY SECTIONS OF FINAL CONFERENCE REPORT (2005), available at http://www.tvppa.com/conferences/presentations/05AF/MORGANMEGUIRE_H-S-FINALEnergyBillTable10-05.pdf.

judiciary. Many significant rulemakings and litigated proceedings are pending at the FERC, which is working toward developing policies that foster competitive markets while also implementing new rules and regulations prompted by the Energy Policy Act of 2005. This article briefly recaps RTO and ISO development beginning with Order No. 888 and surveys the current trends in regions across the country as policy development continues to evolve.

There are also many issues that are unresolved. Regulators continue to explore what is the best approach to ensuring resource adequacy, including how to adequately compensate generators that are needed for reliability. In addition, Congress and the FERC have sought to prevent energy market manipulation. While the Energy Policy Act of 2005 prohibited energy market manipulation and enhanced the Commission's authority to assess civil penalties for violations, it is unclear what roles ISOs and RTOs should have concerning the prevention of market manipulation and the exercise of market power. These are among the many issues that merit further consideration as the industry continues to rapidly change. However, with federal, regional, and state level coordination, competitive electricity markets will deliver the reliability, security, and efficiency that consumers deserve.

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