

REPORT OF THE ELECTRICITY REGULATION COMMITTEE

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I. INTRODUCTION

This report provides a summary of significant decisions, orders, or rules issued by the Federal Energy Regulatory Commission (FERC or Commission) or by the United States Courts of Appeals on review of the Commission's orders in 2006 and early 2007. The first part of the report addresses developments in the various Regional Transmission Organizations (RTOs) that are in different stages of development around the country. The report then addresses a number of significant Commission orders and rules implementing various provisions of the Energy Policy Act of 2005 (EPAct 2005). This legislation was one of the most significant changes to the Federal Power Act in over a decade, and the Commission's implementation of this legislation is addressed in this report. This report also includes expanded sections on Corporate/Affiliate and section 203/Merger Developments due to the significant developments in these areas. Many thanks to the Finance and Transactions Committee of the Energy Bar Association for contributing this additional analysis and discussion. Please see that Committee's report for a list of committee members.

II. REGIONAL TRANSMISSION ORGANIZATION DEVELOPMENTS

A. *General Developments*

1. Summary of the FERC's Rule on Long-Term Transmission Rights

On July 20, 2006, the FERC issued Order No. 681,¹ a Final Rule requiring that RTOs, Independent System Operators (ISOs), or any other "Transmission Organization" that operates organized markets in which congestion is managed through financial rights to make available long-term firm rights (LTTRs) to load-serving entities (LSEs) and other market participants.

a. Background

Section 1233(b) of the EPAct 2005 requires the FERC to adopt, within one year of the passage of EPAct 2005, a rule or order implementing "section 217(b)(4) of the Federal Power Act [], as defined by that Act with organized electricity markets."² Section 217(B)(4), in turn, requires that the FERC exercise its authority:

in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, and enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs.

The FERC implemented this directive in section 1233(b) through Order No. 681.

1. Order No. 681, *Long-Term Firm Transmission Rights in Organized Electricity Markets*, [2006 Proposed Regs.] F.E.R.C. STATS. & REGS. ¶ 31,226 (2006), 71 Fed. Reg. 43, 564, 116 F.E.R.C. ¶ 61,077 (2006), *order on reh'g*, Order 681-A, 117 F.E.R.C. ¶ 61,201 (2006) [hereinafter Order No. 681].

2. Energy Policy Act of 2005, Pub. L. No. 109-58, § 1233(a), 119 Stat. 594.

3. *Id.*

b. Order No. 681

i. Overview

Order No. 681 requires each Transmission Organization that manages congestion through the use of auction-based day-ahead and real-time markets—the New York Independent System Operator (NYISO), ISO-New England, PJM Interconnection, LLC, the Midwest Independent Transmission System Operator, Inc., and the California Independent System Operator Corporation—to file, by January 29, 2007, tariff sheets providing for LTTRs that comport with the directives in Order No. 681.⁴

Order No. 681 adopts the approach proposed by the Commission in its February 2006 Notice of Proposed Rulemaking (NOPR)—to require that Transmission Organizations adopt LTTRs that satisfy a series of guidelines, but otherwise to give Transmission Organizations flexibility to develop their own LTTR proposals. The guidelines adopted by the Final Rule are very similar to those proposed in the NOPR. They are as follows:

“[T]he long-term firm transmission right should. . . specif[y] a source (injection node or nodes) and sink (withdrawal node or nodes), and a quantity;”⁵

[T]he long-term firm transmission right must provide a hedge against [day-ahead] locational marginal pricing congestion charges (or other direct assignment of congestion costs) for the period covered and quantity specified. Once allocated, the financial coverage provided by [a financial long-term] right should not be modified during its term [the “full funding” requirement] except in the case of extraordinary circumstances or through voluntary agreement of both the holder of the right and the transmission organization;⁶

“[L]ong-term firm transmission rights made feasible by transmission upgrades or expansions must be [made] available upon request to any party that pays for such upgrades or expansions in accordance with the transmission organization’s prevailing cost allocation methods for upgrades or expansions;”⁷

“[L]ong-term firm transmission rights must be made available with term lengths (and/or rights to renewal) that are sufficient to meet the needs of load serving entities to hedge long-term power supply arrangements made or planned to satisfy a service obligation. The length of term of renewals may be different from the original term.⁸

“Transmission organizations may propose rules specifying the length of terms and use of renewal rights to provide long-term coverage, but must be able to offer firm coverage for at least a 10-year period;”⁹

Load-serving entities must have priority over non-load serving entities in the allocation of long-term firm transmission rights that are supported by existing transmission capacity. The transmission organization may propose

4. Order No. 681, *supra* note 1, at P 1.

5. *Id.* at P 108.

6. Order No. 681, *supra* note 1, at P 122.

7. *Id.* at P 185.

8. Order No. 681, *supra* note 1, at P 217.

9. *Id.* at P 256.

reasonable limits on the amount of existing transmission capacity used to support long-term firm transmission rights;¹⁰

A long-term transmission right held by a load-serving entity to support a service obligation should be re-assignable to another entity that acquires that service obligation;¹¹ and

The initial allocation of the long-term firm transmission rights shall not require recipients to participate in an auction.¹²

In addition to issuing LTTRs that comport with these requirements, Order No. 681 requires each Transmission Organization, subject to the rule, to engage in planning and expansion processes that ensure that LTTRs will remain feasible over their entire terms. Each Transmission Organization, subject to the rule, also must include in its compliance filing an express demonstration of how its planning and expansion practices will ensure LTTR feasibility for their full terms.¹³

ii. Changes from NOPR

Although Order No. 681 adopted the general approach to LTTRs set forth in the NOPR, it made some notable changes to the Commission's original proposal.¹⁴

iii. Modification of Load-Serving Entity Preference

As set forth in the NOPR, Guideline 5 would have granted priority to LTTRs from existing capacity to LSEs with long-term power supply arrangements. In response to comments from various RTOs and ISOs that policing the long-term power supply requirement would have been difficult, the FERC modified the Guideline to ensure that LSEs generally are given a preference over non-LSEs to LTTRs from existing system capacity, but otherwise to eliminate the preference for LSEs with long-term supply arrangements over LSEs without such arrangements.¹⁵

The Commission also modified Guideline 5 by adding a provision allowing a Transmission Organization to "propose reasonable limits on the amount of existing [transmission] capacity used to support long-term firm transmission rights."¹⁶ This modification is intended to balance the potential adverse effects of LTTR implementation on utilities that prefer shorter-term rights; in this way, it is also meant to compensate for the deletion of Guideline 8 (discussed below).¹⁷

10. Order No. 681, *supra* note 1, at ¶ 30,581.

11. *Id.*

12. Order No. 681, *supra* note 1, at P 33.

13. *Id.* at P 20.

14. Order 681, *supra* note 1, at P 23.

15. *Id.* at P 23.

16. Order 681-A, *Long-Term Firm Transmission Rights in Organized Elec. Mkts.*, 117 F.E.R.C. ¶ 61,201 at P 15 (2006), *reh'g pending* [hereinafter Order No. 681-A].

17. *Id.* at P 23.

iv. Deletion of Guideline 8

Guideline 8 in the NOPR would have required that an “[a]llocation of long-term firm transmission rights should balance any adverse economic impact between participants receiving and not receiving the right.”¹⁸ In response to comments that such a requirement could have had the effect of making it more difficult to implement LTTRs (because of the difficulty in satisfying the directive that the adverse economic impacts be balanced), the Commission deleted this guideline. To address the same concern that animated Guideline 8—that market participants preferring short-term rights not be unduly disadvantaged by the implementation of LTTRs—the Commission amended Guideline 5 to allow Transmission Organizations to “propose reasonable limits” on the amount of transmission capacity allocated to LTTRs.¹⁹

v. Length of LTTRs

Guideline 4 in the NOPR required that LTTRs be of sufficient length to allow LSEs to hedge against congestion costs that are part of long-term power supply arrangements, but otherwise gave Transmission Organizations the flexibility to determine the length of LTTRs. Order No. 681 introduces more specificity to the requirement, mandating that LTTRs have a term of at least ten years. The adoption of this requirement appears to constitute an express rejection of arguments by the NYISO (and others) that there was no need to implement a right in New York with a duration of longer than one-year.²⁰

vi. Expansion LTTRs

In the NOPR, Guideline 3 required that LTTRs made available through expansions of the grid be granted for the life of the upgrade, unless the entity funding the upgrade (and receiving the associated LTTRs) agreed to a lesser term. Order No. 681 states that because of difficulties associated with defining the life of a transmission upgrade, LTTRs obtained through transmission expansions will have a duration developed individually by each Transmission Organization, “based on existing market rules and stakeholder needs.”²¹

vii. Transmission Planning and Expansion

The NOPR would have adopted only the LTTR guidelines, but would not have imposed any specific requirements on Transmission Organizations with respect to planning and expansions. The Final Rule adds the requirement (outlined above) that Transmission Organizations engage in planning and expansion processes to ensure that LTTRs will remain feasible over their entire terms.²²

18. Notice of Proposed Rulemaking, *Long-Term Firm Transmission Rights in Organized Elec. Mkts.*, [2006 Proposed Regs.] F.E.R.C. STATS. & REGS. ¶ 32,598 (2006), 71 Fed. Reg. 6693 (2006).

19. *Id.* at P 59.

20. Order No. 681, *supra* note 1, at P 71.

21. *Id.* at P 23.

22. Order No. 681, *supra* note 1, at P 23.

c. Order No. 681-A

Although it leaves intact the core structure adopted in the Final Rule, Order No. 681-A provides clarifications of certain issues.

i. Preference Tied to Payment of Embedded Costs

The FERC clarifies that the priority of an LSE to LTTRs is tied to whether the LSE pays the long-term embedded costs of the Transmission Organization's transmission system. An LSE

is entitled to a preference in the allocation of long-term firm transmission rights within a transmission organization's region only to the extent that the transmission organization plans and constructs its transmission system to support the load of the load serving entity, and the load serving entity contributes to the cost that the transmission organization incurs for that purpose.²³

ii. Allocation Priority for LSEs with Long-Term Supply Arrangements

Guideline 5—requiring that LSEs have priority over non-LSEs in the allocation of LTTRs—replaced a proposal in the FERC's NOPR that would have given priority not just to LSEs, but to LSEs with long-term power supply arrangements. Order No. 681-A refuses rehearing requests by certain parties that the Commission revert back to the NOPR proposal, and give the priority to LSEs with long-term power supply arrangements.

In reaffirming its adoption of Guideline 5, the FERC stated its expectation that “in general, the transmission organization will be able to allocate sufficient long-term firm transmission rights to hedge power supply arrangements used to meet base load[.]”²⁴ The Commission also acknowledged, however, that “a transmission system may temporarily not have enough capacity to provide simultaneously feasible, long-term firm transmission rights to all load serving entities at this level.”²⁵ The FERC states that in these circumstances, a Transmission Organization may develop an allocation mechanism that gives first priority to LTTRs to LSEs with long-term supply arrangements.²⁶

iii. Whether Grandfathered Rights May Substitute for LTTRs

The NYISO sought clarification that LSEs' “entitlement to receive new long-term firm transmission rights should be reduced to the extent that they already hold grandfathered . . . rights.”²⁷ The theory was that grandfathered rights holders already receive long-term price certainty and stability for their grandfathered transmission service.

The FERC clarified that grandfathered rights may serve as a substitute for LTTRs only if they satisfy each of the guidelines in Order No. 681. The FERC declined to decide whether the grandfathered rights in the NYISO satisfy those

23. Order 681-A, *supra* note 16, at P 78.

24. *Id.* at P 70.

25. Order 681-A, *supra* note 16, at P 70.

26. *Id.*

27. Order 681-A, *supra* note 16, at P 83.

guidelines, and directed the NYISO and other Transmission Organizations to raise the issue in their compliance filings.

iv. Whether Needs of State Retail Access Programs and Preferences of Market Participants May Be Considered in Determining Amount of Existing Capacity Allocated to LTTRs?

The NYISO also asked for clarification to consider the needs of state retail access programs and the preferences of its market participants in determining how much existing transmission capacity should be allocated to LTTRs. The FERC responds that it expects the NYISO and other "Transmission Organization[s] to make available from existing transmission system capacity sufficient long-term firm transmission rights to meet the 'reasonable' needs of all . . . load serving entities."²⁸ The FERC clarifies further that "[i]n most cases . . . the reasonable needs of load serving entities will be met if each load serving entity is able to request and obtain, at its option, a quantity of long-term firm transmission rights sufficient to hedge its long-term power supply arrangements at a base load level."²⁹ According to the FERC, "setting aside capacity for long-term rights in this manner will achieve the result that NYISO seeks."³⁰

v. Frequency of LTTR Allocation

The Commission clarifies that a Transmission Organization "need not allow for the allocation or reconfiguration of long-term firm transmission rights more frequently than once per year."³¹ However, the FERC also indicates that a Transmission Organization may not be able to allocate such rights on a basis less frequent than one year; any proposal to allocate LTTRs less frequently than once per year must be fully supported in a Transmission Organization's compliance filing.³²

2. Market Monitoring Unit

a. Upcoming FERC Technical Conference on MMU Policies

In a December 5, 2006, order on rehearing involving revisions to PJM's tariff governing activities of the Market Monitoring Unit (MMU), the Commission announced its intent to initiate a broad review of its MMU policies and, thereafter, hold a technical conference.³³ In this order, the Commission recognized that the PJM proceeding had engendered stakeholder comments regarding a number of generic concerns with respect to the independence of MMUs and the need for transparency and clarity to MMU functions. Rather than addressing these concerns solely with respect to the PJM MMU, the

28. *Id.* at P 88.

29. Order 681-A, *supra* note 16, at P 88.

30. *Id.*

31. Order 681-A, *supra* note 16, at P 89.

32. *Id.*

33. *PJM Interconnection, L.L.C.*, 117 F.E.R.C. ¶ 61,263 (2006).

Commission announced its intention to conduct a broader MMU policy review that would not necessarily be limited to an MMU within any one RTO or independent system operator.³⁴ Since the issuance of this order, the Commission has now announced an April 2007 technical conference on MMU issues.

B. *Midwest ISO*

1. Resource Adequacy Requirements (RAR)

When the FERC conditionally approved the Energy Markets in an August 6, 2004, order, the FERC mandated that the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) replace the interim Module E requirements with a permanent RAR.³⁵ The Midwest ISO addressed the status of this RAR requirement in a June 6, 2006, informational filing to the FERC in which the Midwest ISO proposed two Phases: (1) Phase I is an “ancillary services market for short-term contingency reserves;”³⁶ and (2) Phase II will consist of: (a) “implementation of [enhanced] [D]emand [S]ide [M]anagement programs;”³⁷ (b) “longer term [F]inancial [T]ransmission [R]ights;”³⁸ (c) “facilitation of longer term energy contracts by [M]arket [P]articipants;”³⁹ (d) “coordination and resolution of seams issues with neighboring [RTOs];”⁴⁰ and (e) “coordination of [RARs] with national and regional . . . standards.”⁴¹

The FERC’s September 26, 2006, Order responded to the June 6, 2006, filing and required the Midwest ISO to work with its stakeholders, particularly the Organization of Midwest ISO States, to implement RAR.⁴² The FERC directed that the Phase I filing include either:

(a) provisions, for implementation in summer 2007, for the commitment and dispatch of interruptible demand, behind[-]the[-]meter generation and other demand resources that are capable of providing operating reserves and short-term contingency reserves; or (b) an explanation and rationale for not including such provisions in its tariff and identifying specific barriers, causes or issues that prevented the filing.⁴³

The FERC also encouraged the Midwest ISO to continue to try to develop an Energy Only Market (EOM) to meet RAR requirements (*i.e.*, “we believe that an EOM could be a just and reasonable approach to addressing resource adequacy needs for the region in the future.”)⁴⁴ Although the Order did not

34. *Id.* at P 19.

35. *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 F.E.R.C. ¶ 61,163 at P 388 (2004).

36. *Midwest Indep. Transmission Sys. Operator, Inc.*, 116 F.E.R.C. ¶ 61,292 at P 6 (2006) [hereinafter *MISO 116*].

37. *Id.*

38. *MISO 116, supra* note 36, at P 6.

39. *Id.*

40. *MISO 116, supra* note 36, at P 6.

41. *Id.* at P 7.

42. *MISO 116, supra* note 36, at P 51.

43. *Id.*

44. *MISO 116, supra* note 36, at P 53.

mandate any specific milestones, it “accept[ed] the Midwest ISO’s commitment to file Phase I in Fall of 2006 and to file Phase II in 2007.”⁴⁵

The Order specifically requires that the ASM filing contain “a more detailed [timeline]”⁴⁶ for implementing RAR, including: (1) milestones and deadlines for both phases of the ASM project; (2) detailed implementation plans; and (3) timelines to fully respond to EOM concerns.⁴⁷ The FERC “expect[s] the Midwest ISO to meet these milestones and deadlines once established. This is critical for the successful and timely development of a permanent resource adequacy plan for the region.”⁴⁸

Midwest ISO is working with the stakeholders and OMS to develop RAR milestones and implementation plans.

2. Regional Expansion Criteria and Benefits Filing

On October 7, 2005, the Midwest ISO filed new and revised tariff sheets with the Commission⁴⁹ in compliance with its July 8, 2004, Order regarding network upgrades.⁵⁰ As part of that Regional Expansion Criteria and Benefits Filing (RECB I), the Midwest ISO defined RBP as:

Network Upgrades [that are] proposed by the Transmission Provider, Transmission Owner(s), ITC(s), Market Participant(s), or regulatory authorities as beneficial to one or more Market Participant(s) but [that are] not determined by the Transmission Provider to be Baseline Reliability Projects [(BRPs)] or new Transmission Access Projects and [that] provide sufficient benefits as determined by the Transmission Provider to justify inclusion in the MTEP.⁵¹

Until the Midwest ISO derived a new proposal, cost responsibility for RBP would be negotiated on a case-by-case basis.⁵²

The Commission conditionally accepted the RECB I Filing in the February 3 Order and concluded that it is important for the Midwest ISO and Market Participants to develop procedures in a timely manner for the cost allocation for RBP. The Order required the Midwest ISO to file a proposal for cost allocation of RBP on or before June 1, 2006.⁵³ On May 18, 2006, the Midwest ISO filed a Motion for Extension of Time with the Commission to make the subject compliance filing on September 1, 2006.⁵⁴ The FERC granted this request on

45. *Id.* at P 13.

46. *MISO* 116, *supra* note 36, at P 57.

47. *Id.*

48. *MISO* 116, *supra* note 36, at P 57.

49. *Midwest Indep. Transmission Sys. Operator, Inc.*, Cost Allocation Policy Filing, No. ER06-18-000 (F.E.R.C. Oct. 7, 2005) [hereinafter RECB Filing].

50. *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 F.E.R.C. ¶ 61,027 at P 38 (2004) (accepting, in part, the Midwest ISO’s compliance filings to Order Nos. 2003 and 2003-A), *order on reh’g*, 109 F.E.R.C. ¶ 61,085 (2004).

51. RECB Filing, *supra* note 49, at § 1.262(a).

52. *Id.*

53. *Midwest Indep. Transmission Sys. Operator, Inc.*, 114 F.E.R.C. ¶ 61,106 at P 90 (2006).

54. Motion for Extension of Time of Midwest ISO, *Midwest Indep. Transmission Sys. Operator, Inc.*, 114 F.E.R.C. ¶ 61,106 (filed May 18, 2006) (No. ER06-18-000).

May 31, 2006.⁵⁵ On August 16, 2006, the Midwest ISO filed a second Motion for Extension of Time with the Commission to make the subject compliance filing on November 1, 2006.⁵⁶ The FERC granted this request on August 17, 2006.⁵⁷

The RECB II filing was made on November 1, 2006, in Docket No. ER06-18, to address Economic Network Upgrade Projects.⁵⁸ Normally, the FERC would have sixty days (until 1/1/07) to issue an order in such a section 205 filing. However, the Midwest ISO proposed an effective date for RECB II filing of April 1, 2007, and requested a waiver of the usual FERC procedures (so that the OMS and others would have time to consider the issues).⁵⁹

3. Cross Border Project Cost Allocations

The Midwest ISO Open Access Transmission and Energy Markets Tariff (Midwest ISO Tariff), the PJM Open Access Transmission Tariff (PJM Tariff) and the Amended and Restated Operating Agreement of PJM (Operating Agreement) were in compliance with the Commission's previous November 18, 2004 Order.⁶⁰ By a November 21 Order, the Commission directed the Midwest ISO, PJM Interconnection and their Transmission Owners to (i) file a "proposal addressing the distinction between reliability and economic transmission projects; whether and how these [two] categories of projects should be planned for differently; and finally, how costs should be allocated for economic projects to produce just and reasonable results,"⁶¹ and (ii) provide, within ninety days, supplemental information regarding the joint RTO planning model and the timeline for the mid-cycle review, and to correct the noted discontinuity in the Midwest ISO Tariff.⁶² On April 20, 2006, the RTOs filed separate competing compliance filings regarding cost allocation responsibility for constructing reliability transmission facilities, in large part because the RTOs' stakeholders were unable to reach a consensus on how to apply the transfer distribution factor (DFAX) calculation to determine the impact of flows in one RTO on a constraint located in the other RTO. In a September 21 Order, the Commission directed staff to convene a technical conference to address the issues raised in the competing proposals and to report back to the Commission on their findings

55. Notice Granting Midwest ISO's 5/18/06 Request for an Extension of Time, *Midwest Indep. Transmission Sys. Operator, Inc.*, 114 F.E.R.C. ¶ 61,106 (filed May 31, 2006) (No. ER06-18-000).

56. Motion for Extension of Time of Midwest ISO, *Midwest Indep. Transmission Sys. Operator, Inc.*, 114 F.E.R.C. ¶ 61,106 (filed Aug. 16, 2006) (No. ER06-18-000).

57. Notice Granting Midwest ISO's 8/16/06 Request for a Further Extension of Time, *Midwest Indep. Transmission Sys. Operator, Inc.*, 114 F.E.R.C. ¶ 61,106 (filed Aug. 17, 2006) (No. ER06-18-000).

58. Midwest ISO Submits Proposed Revisions to Open Access Transmission & Energy Markets Tariff to Comply with FERC's 2/3/06 Order, *Midwest Indep. Transmission Sys. Operator, Inc.*, Economic Network Upgrades Filing, No. ER06-18-004 (F.E.R.C. Nov. 1, 2006) [hereinafter RECB II Filing].

59. RECB II Filing, *supra* note 58, at 11.

60. *Midwest Indep. Transmission Sys. Operator, Inc.*, 109 F.E.R.C. ¶ 61,168 (2004); *Midwest Indep. Transmission Sys. Operator, Inc.*, 113 F.E.R.C. ¶ 61,194 at P 1 (2005).

61. *Id.* at PP 12, 24.

62. 113 F.E.R.C. ¶ 61,194 at PP 16, 17, 19, 39.

within 150 days of the order.⁶³ This technical conference was held on December 5, 2006.

4. Revenue Sufficiency Guarantees (RSG)

The Midwest ISO's EMT provides for RSG to encourage generators to participate in the Reliability Assessment Commitment (RAC) process by making them whole in case the Real-Time LMP is insufficient to cover their production costs.⁶⁴ Since they involve system-wide reliability benefits, RSG payments are generally funded through uplift to load.

On October 27, 2005, the Midwest ISO filed with the Commission proposed revisions to section 40.3.3.a of the Midwest ISO's EMT for the following purposes: (1) to remove references to virtual supply from the provisions on the calculation of RSG charges; (2) to clarify the allocation of RSG charges among eligible categories of Market Participants; and (3) to make Generation Resources that do not follow Dispatch Instructions eligible to receive RSG payments for the lesser of the energy actually produced, or the instructed megawatts.

On April 25, 2006, the Commission issued an Order that conditionally accepted most of the Midwest ISO's proposed tariff changes, and rejected others, requiring the Midwest ISO to recalculate, refund, and/or credit certain RSG payments.⁶⁵ On May 17, 2006, the Commission issued a Notice of Extension of Time, granting the request of the Midwest ISO for more time to comply with the April 25 Order.

On October 26, 2006, the Commission issued a Rehearing Order that affirmed several directives of the April 25 Order, reconsidered certain rulings (including the refund directive concerning virtual transactions), and imposed further compliance requirements.⁶⁶ On November 27 and December 22, 2006, the Midwest ISO submitted its compliance filings for the October 26 Rehearing Order. The December 22 filing addressed the October 26 Rehearing Order's directives that the Midwest ISO perform an analysis of virtual transactions and submit proposed tariff revisions allocating to such transactions an appropriate share of RSG costs.⁶⁷ These RSG proceedings remain pending before the Commission.

5. Ancillary Services Markets

The August 6 FERC Order directed the Midwest ISO to state its timetable for implementing markets for regulation and operating reserves.⁶⁸ In compliance with this directive, the Midwest ISO stated its intention in an October 5, 2004,

63. *MISO* 116, *supra* note 36, at PP 1, 23.

64. *Midwest Indep. Transmission Sys. Operator, Inc.*, 107 F.E.R.C. ¶ 61,191 (2004); *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 F.E.R.C. ¶ 61,163 (2004), *order on reh'g*, 109 F.E.R.C. ¶ 61,157 (2004), *order on reh'g*, 111 F.E.R.C. ¶ 61,043 (2005).

65. *Midwest Indep. Transmission Sys. Operator, Inc.*, 115 F.E.R.C. ¶ 61,108 (2006).

66. *Midwest Indep. Transmission Sys. Operator, Inc.*, 117 F.E.R.C. ¶ 61,113 (2006).

67. *Id.* at P 117-19.

68. *See generally Midwest Indep. Transmission Sys. Operator, Inc.*, 108 F.E.R.C. ¶ 61,163 (2004).

compliance filing to implement a market for regulation reserves and a market for operating reserves.

The Midwest ISO has been working with its stakeholders to develop an Ancillary Services Market (ASM) and conducted many stakeholder meetings during late 2005, and has continued throughout 2006. The Ancillary Services Task Force was formed to research, develop, and recommend the processes, criteria, and business rules for the Regulation and Operating Reserves Ancillary Services Markets. This task force is formed to assist Midwest ISO with its compliance with the FERC with respect to the implementation of ASMs for regulation and operating reserves.

On January 15, 2007, the Midwest ISO released initial draft ASM tariff sheets for stakeholder review and commenced a series of meetings to receive feedback. The ASM filing is planned for early in 2007, with an effective date of the spring of 2008.

6. Grandfathered Agreements (GFAs)

The Midwest ISO administers GFAs based on guidance from several Commission orders,⁶⁹ and section 38.8 of the EMT. GFAs are either “carved out” of the Energy Markets or select one of three kinds of treatments, denominated Option “A,” “B,” and “C” GFA treatment. The carve-outs and the optional treatments shall expire no earlier than February 1, 2008, and thereafter upon the Commission’s approval of the Midwest ISO’s proposal, due on February 1, 2007, regarding the treatment of GFAs beyond 2008.⁷⁰

Meanwhile, the Midwest ISO has been submitting quarterly reports on GFAs, indicating that for the most part, carved-out GFAs have been submitting Day-Ahead Schedules which, although financially non-binding, have been largely accurate. The Midwest ISO has also continued to work through disputes with GFAs. The Commission has ruled that carved-out GFAs should not be subjected to RSG charges.⁷¹ In one dispute involving alleged load growth associated with a GFA, the Commission also confirmed that Option B treatment of GFAs is not available to parties that had not settled upon that option before July 28, 2004.⁷²

On January 22, 2007, the Midwest ISO filed proposed revisions to Attachment P to the EMT indicating that a number of GFAs have already terminated.⁷³

C. Southwest Power Pool

On January 4, 2006, the Southwest Power Pool, Inc. (SPP) filed proposed open access transmission tariff (OATT) revisions to implement a real-time

69. *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 F.E.R.C. ¶ 61,236 at P 268 (2004), *order on reh’g*, 111 F.E.R.C. ¶ 61,042 (2005), *order on reh’g*, 112 F.E.R.C. ¶ 61,311 (2005).

70. *Midwest Indep. Transmission Sys. Operator, Inc.*, 111 F.E.R.C. ¶ 61,042 at P 106 (2005).

71. *ALLETE, Inc. v. Midwest Indep. Transmission Sys. Operator, Inc.*, 114 F.E.R.C. ¶ 61,325 (2006); *S. Ill. Power Coop. v. Midwest Indep. Transmission Sys. Operator, Inc.*, 114 F.E.R.C. ¶ 61,234 (2006).

72. *Minnesota Mun. Power Agency v. N. States Power Co.*, 114 F.E.R.C. ¶ 61,004 at P 22 (2006).

73. Attachment P Filing, *Midwest Indep. Transmission Sys. Operator, Inc.*, No. ER07-450-000 (F.E.R.C. Jan. 22, 2007).

energy imbalance market (EIS Market) and establish a market monitoring and market power mitigation plan. SPP's filing included proposed Attachment AE, to implement least-cost, bid-based, security-constrained, economic dispatch and locational marginal pricing, including provisions allowing the bidding, scheduling and dispatch of generating units; proposed Attachment AF, SPP's market power mitigation plan, which sets out the principles for mitigating economic withholding and requires the SPP market monitor to monitor for violations of existing market behavioral rules and monitor for potential instances of market manipulation; and proposed Attachment AG, SPP's market monitoring plan. Additionally, SPP proposed to make certain conforming changes to its OATT to implement Attachments AE, AF, and AG. The Commission conditionally accepted in part, rejected in part, and suspended in part the filing for five months, effective October 1, 2006, subject to several modifications proposed by the Commission.⁷⁴

On rehearing of the *SPP Market Order*, the Commission ordered further modifications to SPP's OATT to institute a bid cap and an assessment of the state estimator capabilities. The Commission denied requests for rehearing of SPP's mitigation plan, finding that "SPP's mitigation measures, as supported by the monitoring plan, strike an appropriate balance [between under-mitigation and over-mitigation] that will result in just and reasonable rates and enable reliable provision of imbalance service."⁷⁵

In the *SPP Market Order*, the Commission "conditionally accept[ed] SPP's market monitoring proposal as to the split of functions between the internal and external market monitors, subject to further orders in Docket No. ER06-641-000."⁷⁶ On February 15, 2006, SPP filed to incorporate an executed agreement between SPP and Boston Pacific Company, Inc., for a one year term beginning January 1, 2006, into Attachment AJ of SPP's OATT. Under the agreement, Boston Pacific would serve as SPP's external market monitor. The Commission conditionally accepted SPP's proposed revisions, subject to modification.⁷⁷ The Commission found "that SPP's filing clarifies the division of responsibilities between SPP's internal and external market monitors, and to the extent that any responsibilities overlap, provides for a means of resolution in cases of conflict between the market monitors."⁷⁸ On July 26, 2006, the Commission accepted SPP's compliance filing revising pages in its OATT, including a revision to provide for monitoring by the external market monitor prior to implementation of SPP's EIS market, effective January 1, 2006.⁷⁹

Additionally, the Commission, in the *SPP Market Order*, directed SPP and its control area operators "to negotiate before a settlement judge the proper allocation of functional responsibilities, costs and liability associated with SPP's new role in its region."⁸⁰ SPP filed an offer of settlement, including an

74. *Southwest Power Pool, Inc.*, 114 F.E.R.C. ¶ 61,289 (2006) [hereinafter *SPP Market Order*].

75. *Id.* at P 17.

76. *SPP Market Order*, *supra* note 74, at P 134.

77. *Southwest Power Pool, Inc.*, 115 F.E.R.C. ¶ 61,051 (2006).

78. *Id.* at P 1.

79. *Southwest Power Pool, Inc.*, 116 F.E.R.C. ¶ 61,086 (2006).

80. *SPP Market Order*, *supra* note 74, at P 91.

agreement negotiated between SPP and SPP balancing authorities outlining the allocation of the tasks within the balancing function and the reliability function in the EIS Market (Balancing Function Agreement), and a proposed resolution of the allocation of liability among SPP and the balancing authorities.⁸¹ SPP and the balancing authorities were unable to develop a tariff provision on balancing authority cost recovery in the sixty days allotted by the Commission for compliance with the SPP Market Order, and the parties agreed to develop such provision at a later date.⁸² On November 17, 2006, the Commission conditionally approved the partially contested settlement, subject to modification of three sections, effective as of the start of the EIS market.⁸³ On December 15, 2006, SPP filed the Balancing Function Agreement as new Attachment AN to the SPP OATT, as well as revisions to the section 8 of Attachment AE regarding allocation of liability among SPP and the balancing authorities.

On May 16, 2006, in addition to submitting a compliance filing to incorporate the Commission's directive in the *SPP Market Order*, SPP filed new Attachment AH to its OATT "to provide a service agreement for market participants selling energy into the imbalance market."⁸⁴ SPP also proposed "to allocate the costs associated with energy assistance from reserves, as opposed to reserve capacity, directly to the market participant responsible for the resource that caused the need for reserve activation."⁸⁵ The Commission accepted in part, subject to modification, and rejected in part SPP's compliance filing, market participant agreement and reserve cost allocation proposal, to become effective on October 1, 2006.⁸⁶ The Commission found SPP's "proposal to allocate the costs of emergency energy to market participants whose resources cause the reserve activation" just and reasonable.⁸⁷ However, the Commission rejected SPP's proposal "to have balancing authorities invoice market participants, through SPP, using contracts that are not applicable to the market participants."⁸⁸ The Commission directed SPP "to modify its OATT to provide that rates for emergency energy will reflect a pass-through of costs charged to SPP pursuant to a new emergency energy ancillary service schedule in the affected public utilities' OATTs or utilities' reciprocal tariffs."⁸⁹ The Commission also noted that "prior to SPP passing through the cost of this service, any public utility participating in the SPP imbalance market must have on file a Commission-approved schedule for emergency energy."⁹⁰

On October 26, 2006, in an order on rehearing and compliance filing, the Commission granted rehearing in part and clarified that "the Commission will allow reserve sharing charges to be based on the higher of the incremental costs plus an adder consistent with Commission precedent or the LIP for the unit

81. *Southwest Power Pool, Inc.*, 116 F.E.R.C. ¶ 63,001 (2006).

82. *SPP Market Order*, *supra* note 74, at P 4.

83. *Southwest Power Pool, Inc.*, 117 F.E.R.C. ¶ 61,207 (2006).

84. *Southwest Power Pool, Inc.*, 116 F.E.R.C. ¶ 61,053 at P 11 (2006) [hereinafter *Southwest*].

85. *Id.* at P 19.

86. *Southwest*, *supra* note 84.

87. *Id.* at PP 32, 34.

88. *Southwest*, *supra* note 84, at P 40.

89. *Id.*

90. *Southwest*, *supra* note 84.

responding to the reserve sharing event.”⁹¹ The Commission accepted SPP’s compliance filing, subject to modification.

Later in October, the Commission accepted an additional compliance filing by SPP proposing to revise SPP’s OATT, including new Attachment AM (Metering Agent Services Agreement), and an informational filing pursuant to the *SPP Market Order*, subject to clarification.⁹²

On December 22, 2006, SPP submitted materials “demonstrating the readiness of SPP to deploy its Energy Imbalance Services market . . . effective February 1, 2007.”⁹³ SPP noted that there are several matters related to the EIS Market pending before the Commission, but that “[w]ith one exception, i.e., SPP’s Violation Relaxation Limits . . . SPP does not believe that regulatory approval of these matters prior to EIS market implementation is necessary.”⁹⁴

D. California ISO

1. Market Redesign and Technology Upgrade (MRTU)

On September 21, 2006, the Commission conditionally accepted the California Independent System Operator Corporation’s (CAISO) Market Redesign and Technology Upgrade (MRTU) tariff. Significant components of the MRTU Tariff include: a more effective congestion management system; a day-ahead market for trading and scheduling energy; system improvements to increase operational efficiency and enhance reliability; a more transparent pricing system; improved market power mitigation measures; the opportunity for demand resources to participate in the CAISO markets under comparable requirements as supply; and, lastly, a process that respects the resource adequacy requirements established by the states or Local Regulatory Authorities, with provisions to allow the CAISO to procure additional capacity to meet forecasted needs. The Commission has convened a series of technical conferences to address the various implementation issues associated with the MRTU.

2. Related Proceedings Before the California Public Utilities Commission

The California Public Utilities Commission (CPUC) initiated a number of proceedings in 2005-06, including the Resource Adequacy proceeding, the long-term transmission planning proceeding, and the greenhouse gas proceeding, that could have significant implications for the market within California and the Western markets generally.

In late 2005, the CPUC opened the resource adequacy rulemaking to continue its efforts to ensure reliable and cost-effective electricity supply in California through refinement and augmentation of its adopted program of resource adequacy requirements. Under this program, investor-owned utilities (IOUs) as well as the electric service providers (ESPs) and community choice

91. *Southwest Power Pool, Inc.*, 117 F.E.R.C. ¶ 61,110 at P 28 (2006).

92. *Southwest Power Pool, Inc.*, 117 F.E.R.C. ¶ 61,139 (2006).

93. Letter from Jeffrey G. DiSciullo, Attorney for Sw. Power Pool, Inc., to the Honorable Magalie Roman Salas, Sec’y, Fed. Energy Regulatory Comm’n (Dec. 22, 2006).

94. *Id.* at P 6.

aggregators (CCAs) operating within the IOUs' service territories (collectively, load serving entities or LSEs) are required to demonstrate that they have acquired the resources needed to meet their forecasted retail customer load plus a reserve margin.

In conjunction with the RAR proceeding, the CPUC also initiated a Long-Term Procurement Plan (LTPP) proceeding intending to continue the CPUC's efforts to ensure a reliable and cost-effective electricity supply in California through integration of a comprehensive set of procurement policies and review of long-term procurement plans. On December 11, 2006, San Diego Gas & Electric Company (SDG&E), Pacific Gas & Electric Co. (PG&E), and Southern California Edison (SCE) each filed their 2006 LTPPs. The plans follow the outline provided in the LTPP Phase 2 Scoping Memo (*See* September 26, 2006 bullet below) and cover both (1) the procurement processes that each utility uses to conduct procurement, as well as (2) the long-term resource plan (2007-2016) that will guide procurement planning in the future. The 2006 Long-Term Procurement Plans are intended (once adopted) to replace all previous versions of Short-Term and Long-Term Procurement Plans.

In 2006, the CPUC also initiated a proceeding to set a cap on greenhouse gas emissions for generation in California. This proceeding compliments the efforts in the RAR and LTPP proceedings in that it aims to set greenhouse gas performance standards for those resources included in determining the RARs and LTPPs for IOUs within the state of California.

E. ISO New England

The most significant regulatory development for ISO New England Inc. (ISO-NE) during 2006 was the resolution of its contentious Locational Installed Capacity (LICAP) proceeding. On March 2006, ISO-NE, together with a number of other settling parties, filed a settlement that was intended to resolve all issues in that proceeding. Under the settlement, capacity would be contracted for and compensated through Forward Capacity Market (FCM) auctions rather than through a LICAP mechanism. These auctions will procure capacity three-plus years in advance of the commitment period. The first FCM auction will be held in the first quarter of 2008 for the commitment period of June 1, 2010, to May 31, 2011. Prior to the first commitment period of this FCM, the settlement also contains a transition period (December 1, 2006, through June 1, 2010) during which fixed payments will be made to all installed capacity resources. The settling parties asked that the Commission consider the Settlement Agreement as a pursuant to the standards described in *Trailblazer Pipeline Co.*⁹⁵

In June 2006,⁹⁶ the Commission, under the standards announced in *Trailblazer*, accepted the FCM settlement:

concluding that as a package, it presented a just and reasonable outcome that is consistent with the public interest. . . . To make this finding, the Commission utilized the second approach of *Trailblazer*, and concluded "that the parties objecting to the Settlement Agreement would be in no worse position under the

95. *Trailblazer Pipeline Co.*, 85 F.E.R.C. ¶ 61,345 (1998), *order on reh'g*, 87 F.E.R.C. ¶ 61,110 (1999) [hereinafter *Trailblazer*].

96. *Devon Power LLC*, 115 F.E.R.C. ¶ 61,340 (2006), *reh'g denied*, 117 F.E.R.C. ¶ 61,133 (2006).

terms of the settlement than if the case were litigated,” and that the Settlement Agreement, as a package, achieves an overall just and reasonable result within a zone of reasonableness.⁹⁷

On October 1, 2006, as required by the FCM settlement, ISO-NE filed tariff provisions to implement the transition period of the settlement. This filing was accepted by the Commission.⁹⁸ The settlement requires ISO-NE to file on February 15, 2007, to file tariff provisions to implement the permanent FCM market.

Meanwhile, litigation continued with regard to whether the Commission has authority to determine the generation capacity (Installed Capacity Requirement or ICR) required for reliable electric service in New England. Briefs have been filed in *Connecticut Department of Public Utility Control v. FERC*,⁹⁹ and oral argument has been scheduled. As required by the FCM settlement, on December 22, 2006, ISO-NE made a filing¹⁰⁰ at the Commission which describes the process for determining the ICRs need to implement that settlement.

ISO-NE has also moved forward with implementation of refinements to its ancillary services markets. The Commission accepted¹⁰¹ ISO-NE's filing to, among other things, add a locational component to its existing Forward Reserves Market and provisions which would coordinate and optimize the pricing of energy and reserves in real time. These important refinements became operational on October 1.

The Commission also approved¹⁰² refinements ISO-NE proposed concerning its cold weather operating procedures, which, among other things, involve temporary removal of its effective offer price cap during emergency conditions.

The Commission¹⁰³ also denied a complaint against ISO-NE in which complainants requested the Commission to require that all electric generation facilities in Connecticut be compensated on a cost-of-service basis through Reliability-Must-Run agreements until the Commission can determine that electricity markets in Connecticut are competitive. The Commission found that complainants had not supported their burden to show that ISO-NE's existing tariff provisions concerning the compensation of generating facilities needed for reliability in Connecticut are unjust and unreasonable, and their burden to show that their proposed tariff provisions are just and reasonable.

97. *Id.* at P 14.

98. *ISO New England Inc. and New England Power Pool*, 117 F.E.R.C. ¶ 61,132 (2006), *reh'g pending*.

99. *Connecticut Dep't of Pub. Util. Control v. FERC*, Nos. 05-1297, 05-1308, 2006 WL 3489032 (D.C. Cir. Nov. 27, 2006).

100. Letter from Raymond W. Hepper, Attorney for ISO New England Inc., to the Honorable Magalie R. Salas, Sec'y, Fed. Energy Regulatory Comm'n (Dec. 22, 2006), <http://www.isone.com/regulatory/ferc/filings/2006/dec/er07-365-000.pdf>.

101. *New England Power Pool and ISO New England Inc.*, 115 F.E.R.C. ¶ 61,175 (2006), *reh'g denied*, 117 F.E.R.C. ¶ 61,106 (2006).

102. *ISO New England Inc. and New England Power Pool Participants Comm.*, 117 F.E.R.C. ¶ 61,082 (2006).

103. *Richard Blumenthal v. ISO New England Inc.*, 117 F.E.R.C. ¶ 61,038 (2006), *reh'g pending*.

Finally, on November 14, 2006, ISO-NE filed¹⁰⁴ to eliminate its Peaking Unit Safe Harbor mechanism which applied to certain generation units needed for reliability in constrained areas.

F. PJM

The Commission has accepted, consolidated, and set for hearing on January 5, March 1 and 29, May 4, and July 21, 2006, proposals by PJM Interconnection, L.L.C. (PJM) for allocating cost responsibility for transmission upgrades required for reliability under its Regional Transmission Expansion Plan (RTEP).¹⁰⁵ PJM proposed to allocate cost responsibility for many reliability-based upgrades to zones and to merchant transmission projects within a zone based on the extent to which load in the zone contributed to the violation of reliability criteria. The Commission also accepted, subject to refund, and consolidated into this hearing a PJM Transmission Owners' filing proposing to require the merchant transmission owner to pay the transmission expansion costs which PJM has allocated to the merchant transmission project and pay it via a fixed monthly charge.¹⁰⁶

By a November 22, 2006, order, the Commission accepted, subject to conditions and a settlement judge proceeding, PJM's proposed market rules to establish LTTRs¹⁰⁷ to allow load serving entities (LSEs) to hedge congestion costs on a longer than one-year basis. PJM intended this filing to comply with the requirements for RTOs under section 217 of the Federal Power Act¹⁰⁸ and the Commission's rules under section 217 for LTTRs (Order No. 681).¹⁰⁹ The issue set for settlement was whether PJM's proposal to pro rate Auction Revenue Rights (ARRs) provided adequate protection for certain LSE's historical service obligation as required by Order No. 681.

By a May 8, 2006, order, the Commission denied rehearing and granted clarification of an order accepting a tariff filing providing options for transmission owners within PJM to recover the costs of constructing new upgrades, and setting for hearing the continued validity of PJM's current modified zonal rate structure. A July 3, 2006, Initial Decision concluded that, for existing transmission facilities, PJM's modified zonal or "license plate" rate design was unjust and unreasonable, and should be replaced with a "postage stamp" rate design, effective April 1, 2006,¹¹⁰ and phased-in so that no customer receives greater than a ten percent annual rate increase. It concluded that the current RTEP cost allocation methodology should be retained for new facilities.

104. *ISO-NE Proposed Elimination of the Peaking Unit Safe Harbor Mechanism*, 118 F.E.R.C. ¶ 61,108 (2007).

105. *PJM Interconnection, L.L.C.*, 115 F.E.R.C. ¶ 61,261 (2006); *PJM Interconnection, L.L.C.*, 116 F.E.R.C. ¶ 61,118 (2006); *PJM Interconnection, L.L.C.*, 117 F.E.R.C. ¶ 61,058 (2006).

106. *PJM Interconnection, L.L.C.*, 115 F.E.R.C. ¶ 61,345 (2006).

107. *PJM Interconnection, L.L.C.*, 117 F.E.R.C. ¶ 61,220 (2006).

108. Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594, 983-84.

109. Order No. 681, *supra* note 1.

110. *PJM Interconnection, L.L.C.*, 116 F.E.R.C. ¶ 63,007 (2006).

On December 21, 2006, the Commission approved a settlement that will replace PJM's capacity obligation rules effective June 1, 2007.¹¹¹ The new reliability pricing model (RPM) is a three-year forward market using better-defined geographic markets and a mechanism for pricing based on the amount of supply within each localized area in excess of the required minimum (a downward sloping demand curve).

G. New York ISO

The New York power markets continued to mature in 2006 with the issuance of the New York Independent System Operator's (NYISO) first Comprehensive Reliability Plan (CRP) and a series of Federal Energy Regulatory Commission (FERC or Commission) orders providing for further refinement of market rules. In 2006, the FERC approved additional modifications to NYISO's large generator interconnection agreement and procedures to integrate wind projects as well as changes to the voltage support provisions of Rate Schedule 2. The FERC also approved the elimination of the NYISO's Temporary Extraordinary Procedures (TEP) and permitted the streamlining of the NYISO's billing and settlement procedures. Finally, in the courts, the D.C. Circuit upheld the FERC's approval of monthly netting of station power service against jurisdictional challenges lodged by New York electric utilities and the New York State Public Service Commission.

1. NYISO Issues Comprehensive Reliability Plan

New York reached a significant milestone with the issuance of the first ten-year Comprehensive Reliability Plan (CRP) on August 23, 2006. The CRP is intended to review system needs, recommend solutions to meet New York's future electric power needs, and maintain the integrity of the state's bulk power grid.¹¹² In particular, under Attachment Y of the NYISO Open Access Transmission Tariff (OATT), if the NYISO determines that a reliability need cannot be met by existing or planned projects, including qualified market-based solutions, then a responsible transmission owner may be directed to initiate planning of a regulated backstop solution.¹¹³

For purposes of this first CRP, the primary focus was on addressing predicted significant transfer capability declines and power shortfalls in New York due to greater power demand and the scheduled retirement of several generation facilities. In its CRP, the NYISO found, however, that regulatory solutions will not be necessary, as "market-driven solutions and updated project plans by [TOs] are expected to maintain reliability of [New York's] electric grid through 2010."¹¹⁴

In issuing the CRP, the NYISO also expressed confidence in the ability of regulated utilities and private investors to sufficiently develop new and existing

111. *PJM Interconnection, L.L.C.*, 117 F.E.R.C. ¶ 63,331 (2006).

112. Press Release, New York Indep. Sys. Operator, Comprehensive Reliability Plan Released by the NYSIO (Aug. 23, 2006), available at http://www.nyiso.com/public/webdocs/newsroom/press_release [hereinafter NYISO News Release].

113. *Id.*

114. NYISO News Release, *supra* note 112.

facilities to meet system reliability needs through 2015. However, the NYISO expressly reserved the right, in the future, to “intercede to recommend any number of regulated solutions” if it deems the progress of private and regulated-utility development on resolving the identified reliability needs to be unsatisfactory.¹¹⁵

2. NYISO Wind Interconnection Procedures

On January 18, 2006, NYISO, submitted to the FERC a compliance filing proposing revisions to the large generator interconnection procedures and large generator interconnection agreement contained in its open access transmission tariff, to incorporate, with modifications, the standard procedures and technical requirements for the interconnection of large wind generators adopted by the Commission in Order Nos. 661 and 661-A.¹¹⁶ In a March 17, 2006, order, the Commission accepted NYISO’s compliance filing subject to modifications—primarily directed towards removing several proposed independent entity variations from the standard terms under Order Nos. 661 and 661-A:

Rejected NYISO’s proposal to provide individual transmission owners with decisional authority over the reactive power criteria that must be met by wind plants proposing to build in the service territory of each transmission owner;

- Determined that a system impact study is needed before a requirement to provide reactive power can be imposed;
- Determined that it is not necessary at this time to impose a limit on the power output of wind plants; and
- Upheld the practice of permitting wind plants to submit simplified design specifications when submitting an interconnection request.¹¹⁷

3. Voltage Support

The Commission addressed changes to voltage support provisions under Rate Schedule 2 of the NYISO OATT in two separate proceedings. First, in an April 3, 2006, order, the FERC directed that the NYISO eliminate its sunset provision on voltage support payments under Rate Schedule 2, finding that it exposed suppliers to a requirement to provide voltage support services to NYISO without compensation.¹¹⁸ Second, on October 31, 2006, the Commission accepted NYISO’s filed revised tariff sheets to provide compensation to qualified non-generator voltage support resources that supply voltage support services.¹¹⁹ In doing so, NYISO became the first independent system operator to amend its Rate Schedule 2 tariff to allow for voltage support payments to non-generator equipment.

115. *Id.*

116. *New York Indep. Sys. Operator, Inc.*, 114 F.E.R.C. ¶ 61,271 at P 61,867 (2006).

117. *Id.*

118. *New York Indep. Sys. Operator, Inc.*, 115 F.E.R.C. ¶ 61,005 (2006).

119. *New York Indep. Sys. Operator, Inc.*, 117 F.E.R.C. ¶ 61,137 (2006).

4. Elimination of Temporary Extraordinary Procedures

On July 14, 2006, the Commission approved, with modifications, a NYISO proposal to eliminate its price correction procedures referred to as the Temporary Extraordinary Procedures (TEP) and to establish a framework and time limits for non-TEP price corrections in the future.¹²⁰ Specifically, the Commission approved the NYISO's proposed revisions providing for: (1) the criteria for determining that an Energy or Ancillary Services price has been calculated in error and requires correction; (2) a time limit on the reservation of prices for potential correction of no later than 5:00 p.m. on the calendar day after the Operating Day; and (3) procedures for how NYISO will calculate corrected prices. One modification required by the Commission to the price correction procedures was a shortening of the overall time period for completing any price correction to three calendar days (the NYISO had proposed a five business day limit).

5. Monthly Netting of Station Power Service

In *Niagara Mohawk Power Corp. v. FERC*,¹²¹ the D.C. Circuit Court rejected jurisdictional and Administrative Procedures Act (APA) challenges and upheld the NYISO's monthly netting of station service power. In this case, New York electric power utilities and the New York State Public Service Commission had petitioned for review of the FERC orders approving a station service program that allowed monthly netting of station service by wholesale generators on the basis that monthly netting violates the Federal Power Act (FPA) by encroaching upon state jurisdiction over local distribution service and retail energy sales as well as challenging the choice of a monthly netting regime as arbitrary and capricious. The D.C. Circuit Court rejected the jurisdictional challenge primarily on the basis that petitioners had conceded that netting *per se* was not inconsistent with the FPA noting that, "if hourly netting is perfectly consistent with the statute, we see no principled reason why monthly netting violates the [FPA]."¹²² The APA challenges also were rejected with the court holding that the FERC had not mandated the use of monthly netting and had only held that the NYISO's adoption of monthly netting was a reasonable choice.

H. ITC Developments

1. Duke Energy Corporation and MidAmerican Energy Corporation

In July 2005, Duke Power, then a division of Duke Energy Corporation (Duke), and MidAmerican Energy Company (MidAmerican) each filed with the Commission proposed revisions to their open access transmission tariffs (OATTs) that would provide for an independent entity to perform certain OATT-

120. *New York Indep. Sys. Operator, Inc.*, 116 F.E.R.C. ¶ 61,037 (2006).

121. *Niagara Mohawk Power Corp. v. FERC*, 452 F.3d 822 (D.C. Cir. 2006).

122. *Id.* at 828.

related functions for their respective transmission systems.¹²³ The independent entities would be responsible for: (i) evaluating and approving or denying transmission service requests; (ii) calculating Total Transfer Capability (TTC) and Available Transfer Capability (ATC); (iii) operating the Open Access Same Time Information System (OASIS); (iv) evaluating, processing, and approving generation interconnection requests and performing the related analyses; and (v) coordinating transmission planning. The applicants stated that their proposals would further confidence in the market by having an independent entity provide key OATT functions. They also noted that their proposals were modeled after a similar concept that the Commission had recently approved for Entergy Services, Inc. (Entergy).¹²⁴

The Commission conditionally approved the MidAmerican and Duke proposals in orders issued on December 16 and 19, 2005, respectively.¹²⁵ The Commission's approved was made under the standards of Order No. 888¹²⁶ and not under the Regional Transmission Organization (RTO) standards of Order No. 2000.¹²⁷ In other words, the Commission explained, the question was whether the proposals tended to improve the existing transmission services and decision-making processes offered under the OATT and, therefore, met the "consistent with or superior to" standard under Order No. 888, and not whether the proposals met each of the requirements of an Order 2000-compliant RTO.¹²⁸ Duke retained the Midwest ISO, an existing RTO, to serve as the Independent Entity, and MidAmerican entered into an agreement with TranServ International, Inc., a newly-formed entity that includes certain investors that also are investors in Open Access Technology International, Inc., or OATI.¹²⁹

123. Duke's proposal to install an "Independent Entity" was filed in Docket No. ER05-1236-000, and MidAmerican's proposal to install a "Transmission Service Coordinator" was filed in Docket No. ER05-1235-000. The proposals were filed in conjunction with then-pending corporate transactions, but Duke and MidAmerican each stated explicitly that the proposals were not offered as mitigation in connection with those transactions.

124. *Entergy Servs. Inc.*, 110 F.E.R.C. ¶ 61,295, *order on clarification*, 111 F.E.R.C. ¶ 61,222 (2005) [hereinafter *Entergy Guidance Orders*].

125. *MidAmerican Energy Co.*, 113 F.E.R.C. ¶ 61,274 (2005), *order on compliance*, 115 F.E.R.C. ¶ 61,326, *order conditionally accepting compliance filing*, 116 F.E.R.C. ¶ 61,211 (2006) [hereinafter *MidAmerican*]; *Duke Power*, 113 F.E.R.C. ¶ 61,288 (2005).

126. Order No. 888, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Servs. by Pub. Util.; Recovery of Stranded Costs by Pub. Util. and Transmitting Util.*, [Regs. Preamble 1991-1996] F.E.R.C. STATS. & REGS. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, [Regs. Preamble 1991-2001] F.E.R.C. STATS. & REGS. ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 F.E.R.C. ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 F.E.R.C. ¶ 61,046 (1988), *aff'd in relevant part sub. nom.*; *Transmission Access Pol'y Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2002), *aff'd sub nom.*; *New York v. FERC*, 535 U.S. 1 (2002).

127. Order No. 2000, *Reg'l Transmission Orgs.*, F.E.R.C. STATS. & REGS. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, F.E.R.C. STATS. & REGS. ¶ 30,092 (2000), *aff'd* Pub. Util. Dist. No. 1 v. FERC, 272 F.3d 607 (D.C. Cir. 2001).

128. See, e.g., *Duke Power*, 113 F.E.R.C. ¶ 61,288 at P 18 (2005).

129. Duke and MidAmerican also each entered into arrangements for an independent monitor to perform certain screens and analyses related to the transmission system and to investigate potentially anticompetitive behavior.

2. Louisville Gas and Electric Company and Kentucky Utilities Company

During the pendency of the *Duke Power* and *MidAmerican* filings, a similar proposal was submitted in Docket No. ER06-20-000 by LGE Energy LLC on behalf of its public utility subsidiaries, Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU). In conjunction with their proposal to withdraw from the Midwest ISO, LG&E and KU proposed to delegate to the Southwest Power Pool, Inc. (SPP) certain tariff administration duties and to appoint the Tennessee Valley Authority (TVA) to serve as their Reliability Coordinator. Under their proposal, SPP would serve as the “Independent Transmission Organization” and be responsible for performing essentially the same functions as Duke’s Independent Entity and MidAmerican’s Transmission Service Coordinator. LG&E and KU also stated that their proposal was consistent with the *Entergy Guidance Orders*.

The Commission acted on LG&E’s and KU’s proposal to withdraw from Midwest ISO and to amend their OATT to provide for the Independent Transmission Organization by order issued on March 17, 2006.¹³⁰ Significantly, the Commission determined that in order to address market power concerns that were at issue when the companies originally joined the Midwest ISO, the Independent Transmission Organization, must have “the same level of independent, non-market participant transmission planning that exists today under [LG&E’s and KU’s] existing arrangements with . . . Midwest ISO.”¹³¹ Specifically, the Commission required that SPP, acting as the Independent Transmission Organization, was required to have approval authority over all planning models, criteria, studies, and methodologies for calculating ATC,¹³² and ultimate review and approval authority over planning decisions to the same extent that Midwest ISO had before the proposed withdrawal.¹³³ The Commission further required LG&E and KU to submit protocols delineating how SPP will review and determine TTC.¹³⁴

The Commission also required a number of changes that were not required in the original *Duke Power* and *MidAmerican*¹³⁵ orders to ensure that SPP would be sufficiently independent of LG&E and KU. For example, the Commission required modifications to ensure that: SPP had access to all data that it needed to perform its functions;¹³⁶ any delegations of the requirement to perform studies will only be to non-market participants;¹³⁷ LG&E and KU will not have veto

130. *Louisville Gas and Elec. Co.*, 114 F.E.R.C. ¶ 61,282, *order on compliance*, *E.ON U.S. LLC*, 116 F.E.R.C. ¶ 61,019 (2006) [hereinafter *Louisville Gas*].

131. *Louisville Gas*, *supra* note 130, at P 85.

132. *Id.* at P 143.

133. The Commission further addressed these issues in response to LG&E’s and KU’s compliance filing. *See E.ON U.S. LLC*, 116 F.E.R.C. ¶ 61,019 at PP 48-55 (2006).

134. *Louisville Gas*, *supra* note 130, at P 86. The Commission required LG&E and KU to clarify how SPP and TVA will coordinate their assigned duties and to propose a mechanism for those entities to resolve disputes that may arise between them.

135. The Commission subsequently required MidAmerican to incorporate many of these changes. *See MidAmerican*, *supra* note 125.

136. *Louisville Gas*, *supra* note 130, at P 144.

137. *Id.* at P 145.

authority over SPP personnel decisions;¹³⁸ SPP will have sufficient flexibility to establish budgets, including the right to bring budget and fees disputes before the Commission;¹³⁹ SPP will have rights to make filings with the Commission under section 206 of the Federal Power Act;¹⁴⁰ the stakeholder process and SPP's role in it is clear.¹⁴¹ Finally, the Commission required that SPP quickly brings to the Commission's attention any disputes with LG&E and KU; that SPP make semi-annual reports detailing concerns raised by stakeholders; and that SPP's response to those concerns—as well as any SPP concerns—that aspects of the LG&E and KU OATT may be hindering SPP's ability to perform its Independent Transmission Organization functions.¹⁴²

3. Entergy Services, Inc.

Shortly after issuance of the *Louisville Gas* order, the Commission issued an order addressing Entergy's proposed Independent Coordinator of Transmission (ICT).¹⁴³ The Commission stated that the final ICT agreement between Entergy and SPP must include the same types of provisions required under the *Louisville Gas* order to ensure sufficient independence.¹⁴⁴ Because Entergy had proposed a form of "participant funding" under which transmission and interconnection customers would be required to fund certain transmission upgrades, the Commission paid close attention to the level of independence that SPP would have in the area of transmission planning. Specifically, the ICT will be responsible for independently developing the "Base Plan" (which identifies reliability upgrades) using appropriate multi-regional and regional planning models, and will be required to carefully review Entergy's business practices and local reliability criteria including review of comments submitted by stakeholders.¹⁴⁵ The Commission also addressed provisions under which SPP would serve as the Reliability Coordinator for the Entergy system,¹⁴⁶ and would review transmission availability issues in connection with Entergy's Weekly Procurement Process.¹⁴⁷

138. *Louisville Gas*, *supra* note 130, at P 146.

139. *Id.* at PP 147-48.

140. *Louisville Gas*, *supra* note 130, at P 149.

141. *Id.* at P 151.

142. *Louisville Gas*, *supra* note 130, at P 152.

143. *Entergy Servs. Inc.*, 115 F.E.R.C. ¶ 61,095 (2006). Following on the Entergy Guidance Orders, Entergy had submitted proposed OATT revisions and a draft agreement under which SPP would serve as the ICT.

144. For example, the Commission addressed the level of specificity required in the agreement, including the term of the agreement. *Id.* at PP 91-104; budget issues. 115 F.E.R.C. ¶ 61,095 at PP 104-05; SPP's access to data. *Id.* at PP 106-12; Entergy's relationships with SPP personnel and subcontractors. 115 F.E.R.C. ¶ 61,095 at PP 113-16; and dispute resolution. *Id.* at PP 117-35. Several of these issues were revisited in the Commission's order addressing Entergy's compliance filing. *See Entergy Servs., Inc.*, 117 F.E.R.C. ¶ 61,055 (2006).

145. 115 F.E.R.C. ¶ 61,095 at P 146. The Base Plan is to be posted on OASIS to enable stakeholders to ensure that it followed the requirements of Entergy's OATT. *Id.* at P 147.

146. 115 F.E.R.C. ¶ 61,095 at PP 149-56.

147. *Id.* at PP 246-305. The Weekly Procurement Process was designed to allow merchant generators and other wholesale suppliers to compete to serve Entergy's native load customers. The Commission ruled, "As an independent overseer of transmission service in the Weekly Procurement Process, the ICT will ensure that

Finally, by separate order, the Commission accepted for filing, subject to hearing and settlement procedures, Entergy's proposal to recover the costs that it incurred for past RTO efforts and, going forward, the costs it will incur to fund the ICT.¹⁴⁸ The order was significant in that the Commission determined that:

Entergy's ICT is a significant step forward that should provide benefits in Entergy's footprint, and that Entergy should be allowed to recover start up costs. Denying Entergy the ability to recover start up costs would only serve to make Entergy and other similarly situated entities less likely to pursue the development of an RTO or other proposals that move toward greater independence over the provision of transmission service and provide confidence in the operation of [the] markets.¹⁴⁹

Although the Commission previously had allowed companies that eventually joined RTOs to recover costs incurred for prior unsuccessful efforts,¹⁵⁰ this case marked the first time that an entity that did not join an RTO was permitted to recover such costs.

I. ERCOT

1. Entergy TTC Plan

The power region in Southeast Texas sometimes referred to as the Entergy Settlement Area in Texas (ESAT) moved one step closer to retail open access in 2006 under a transition to competition plan (TTC Plan) filed with the Public Utility Commission of Texas (PUCT) by Entergy Gulf States, Inc. (EGSI).¹⁵¹ The ESAT area, which is within the Southeastern Electric Reliability Council, is governed by the same 1999 Texas legislation that led to the retail choice in Electric Reliability Council of Texas (ERCOT) in January 2002.¹⁵² But in late 2001, the PUCT determined that the necessary retail market institutions for the area would not be fully developed, in place, and tested by January 2002, and therefore delayed opening the market.¹⁵³ Thereafter, the PUCT conducted contested hearings over plans to open the ESAT retail market, which would have been the first retail electric market in Texas outside of the ERCOT and the first retail market in Texas to operate under a FERC-approved Open Access Transmission Tariff (OATT).¹⁵⁴ After the PUCT approved protocols to govern

transmission services granted through the Weekly Procurement Process, is done with rules that are fair to all participants." 115 F.E.R.C. ¶ 61,095 at P 291.

148. *Entergy Servs., Inc.*, 117 F.E.R.C. ¶ 61,320 (2006).

149. *Id.* at P 21.

150. *See, e.g., Alliance Cos.*, 99 F.E.R.C. ¶ 61,105 (2002); *American Elec. Power Serv. Corp.*, 104 F.E.R.C. ¶ 61,013 (2003).

151. PUBLIC UTIL. COMM'N OF TEX., ENTERGY GULF STATES, INC.'S TRANSITION TO COMPETITION PLAN: PROJECT NO. 33687 (2006), http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/33687_1_535094.pdf [hereinafter ENTERGY TTC PLAN].

152. *See* TEX. UTIL. CODE ANN. §§ 39.001-39.457 (Vernon 2006).

153. PUBLIC UTIL. COMM'N OF TEX., STAFF'S PETITION TO DETERMINE READINESS FOR RETAIL COMPETITION IN THE PORTIONS OF TEX. WITHIN THE SE. RELIABILITY COUNCIL: DOCKET NO. 24469 at 3 (2001), http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/24469_168_456484.pdf.

154. *See* PUBLIC UTIL. COMM'N OF TEX., MKT. PROTOCOLS FOR THE PORTIONS OF TEX. WITHIN THE SE. ELEC. RELIABILITY COUNCIL OF TEX.: DOCKET NO. 25089 (2003), <https://www.puc.state.tx.us/openmeet/openmeetarc/2003/050903.pdf>; PUBLIC UTIL. COMM'N OF TEX., PROPOSAL FOR INTERIM SOLUTION FOR RETAIL OPEN ACCESS IN ENTERGY GULF STATES, INC.'S SETTLEMENT

the retail market in 2003, the FERC approved those protocols as an amendment to the Entergy OATT later that year.¹⁵⁵

That progress to open the ESAT area was slowed, however, in the absence of an independent organization to administer the market. As a result, the PUCT delayed retail open access in ESAT until EGSI joined a FERC-approved RTO, such as SPP.¹⁵⁶ But in 2005, the Texas legislature directed EGSI to continue its efforts to achieve retail open access in ESAT, including filing by January 1, 2006, a schedule for achieving certification of a qualified power region and by the end of 2006 a transition to competition plan.¹⁵⁷

In both 2006 filings, EGSI discussed the option of the ESAT area joining SPP and the option that ESAT merge with ERCOT.¹⁵⁸ But in its TTC Plan, EGSI opines that merging ESAT with ERCOT is the most viable path to retail open access.¹⁵⁹ Although SPP is contiguous with and directly interconnected to the ESAT area, EGSI chose ERCOT because of the developed wholesale and retail market structures needed to support retail open access that exist in ERCOT, but are lacking in SPP.¹⁶⁰

The specifics of the Entergy TTC Plan include constructing asynchronous ties between ESAT and ERCOT's Eastern Interconnect: one at the Hartburg Substation in Newton County, Texas and another at the Quarry Substation in Walker County, Texas.¹⁶¹ In sum, EGSI estimates the total cost of the ESAT-ERCOT option under its TTC Plan to be \$927 million.¹⁶² But EGSI also estimates quantifiable benefits of that option at more than \$1 billion and certain other non-quantifiable benefits, including ERCOT avoided transmission costs, ERCOT reliability benefits, and storm hardening and homeland security benefits.¹⁶³ In contrast, EGSI estimates the previously-proposed ESAT-SPP option would not yield positive net benefits, either quantifiable or non-quantifiable.¹⁶⁴

EGSI believes its ESAT-ERCOT option could open the ESAT market to retail open access by January 2013.¹⁶⁵ The TTC Plan acknowledges, however, that before any construction commences to integrate ESAT into ERCOT, the

AREA OF TEX. AND REQUEST FOR COMM'N ACTION: DOCKET NO. 27273 (2003), <http://www.puc.state.tx.us/openmeet/openmeetarc/2003/032103.pdf>; PUBLIC UTIL. COMM'N OF TEX., PETITION OF ENTERGY GULF STATES, INC. FOR CERTIFICATION OF AN INDEP. ORG. FOR THE ENTERGY SETTLEMENT AREA OF TEX.: DOCKET NO. 28818 (2004), <https://www.puc.state.tx.us/publications/update/2004/020504.doc>.

155. *Entergy Servs, Inc.*, 105 F.E.R.C. ¶ 61,318 (2003).

156. PUB. UTIL. COMM'N OF TEX., PETITION OF ENTERGY GULF STATES, INC. FOR CERTIFICATION OF AN INDEP. ORG. FOR THE ENTERGY SETTLEMENT AREA OF TEX.: DOCKET NO. 28818 (2004), <https://www.puc.state.tx.us/publications/update/2004/020504.doc>.

157. See TEX. UTIL. CODE ANN. §§ 39.451-39.457 (Vernon 2006).

158. PUBLIC UTIL. COMM'N OF TEX., ENTERGY GULF STATES, INC.'S PLAN FOR IDENTIFYING APPLICABLE POWER REGION (2005), http://www.puc.state.tx.us/electric/projects/32217/Initial_Filing.pdf; Entergy TTC Plan, *supra* note 151.

159. *Id.* at 13.

160. ENTERGY TTC PLAN, *supra* note 151, at 13.

161. *Id.* at 21.

162. ENTERGY TTC PLAN, *supra* note 151, at 86.

163. *Id.* at 86, 94-96.

164. ENTERGY TTC PLAN, *supra* note 151, at 86.

165. *Id.* at 8.

issue of whether that move would trigger the exercise of FERC jurisdiction over ERCOT's electricity and transmission markets must be resolved.¹⁶⁶ Based on prior FERC orders addressing the provision of transmission service to, from, and over the direct current ties that currently exist between ERCOT and other power pools, EGSI takes the position that its proposed ties should not be a jurisdictional concern.¹⁶⁷ Nevertheless, the TTC Plan includes a commitment by EGSI to seek a declaratory order from the FERC that the proposed interconnection between ESAT and ERCOT will not increase the FERC's jurisdiction over ERCOT.¹⁶⁸

Once that threshold question is answered, additional approvals are necessary to implement the ESAT-ERCOT option. Among them are approval by the Louisiana Public Service Commission of the jurisdictional separation of ESAT from the remainder of EGSI and approval by the FERC under sections 203, 205, 210, and 211 of the Federal Power Act to transfer control of EGSI's Texas transmission facilities to ERCOT.¹⁶⁹ The North American Electric Reliability Council will also need to approve the transfer of operational control of EGSI's Texas transmission facilities to ERCOT.¹⁷⁰

2. Texas CREZ Zones

Texas has experienced a wind rush since 1999, when a state law mandated the addition of 2000 megawatts (MWs) of power from renewable sources by 2009.¹⁷¹ Before that mandate, Texas had less than 1000 MWs of renewable energy capacity. By mid-2006, Texas renewable energy capacity topped the 2,300 MW mark, with enough wind capacity to power 600,000 averaged-sized homes a year. With the express purpose of leading the nation in renewable energy development, in 2005 the Texas legislature enacted a new mandate: adding 3,000 additional MWs of capacity by 2015, and targeting 10,000 MWs by 2025.¹⁷²

In 2006, the PUCT took steps to overcome the "chicken and egg dilemma" by driving the convergence of renewable resources development and transmission construction. The primary step was development of a Final Rule to establish competitive renewable energy zones (CREZ) for the purpose of determining where transmission investment would be prudent.¹⁷³ The CREZ rule permits the PUCT to create CREZs both inside and outside of ERCOT.¹⁷⁴ In designating a CREZ, the PUCT will consider whether the land area is suitable for developing the renewable capacity, the cost of addressing related transmission constraints, the benefits of producing renewable energy in the

166. ENTERGY TTC PLAN, *supra* note 151, at 21.

167. *Id.* at 22-23.

168. ENTERGY TTC PLAN, *supra* note 151, at 22-23.

169. *Id.* at 28-29.

170. ENTERGY TTC PLAN, *supra* note 151, at 29.

171. *See* TEX. UTIL. CODE ANN. § 39.904 (Vernon 2006).

172. *Id.*

173. Resources and Use of Natural Gas, 31 Tex. Reg. 10,783 (Dec. 29, 2006) [hereinafter CREZ Rule].

174. *Id.* at 10,784.

potential CREZ, the level of financial commitment by developers, and any other relevant factors.¹⁷⁵

In December 2006, ERCOT issued a report detailing the potential CREZ areas, transmission congestion related to those areas, and estimated costs of addressing transmission constraints.¹⁷⁶ The next step is for the PUCT to conduct contested proceedings to designate CREZs.¹⁷⁷

Upon approval of a CREZ, the CREZ rule calls for developers to deposit ten percent of their pro rata share of the estimated cost of new transmission facilities within forty-five days of the filing of a certificate of convenience and necessity (CCN) by the transmission service provider (TSP).¹⁷⁸ If any developer fails to deposit the required funds, the PUCT may take various actions, including: reconsideration of its CREZ designation; dismissal of the TSP's CCN application; seeking another developer to step into the shoes of a "defaulting" developer; ordering the return of all deposits to developers who made adequate deposits; ordering the application of the "defaulting" developer's deposits toward the costs incurred by TSPs pertaining to planning and CCN proceedings for the transmission facilities covered by the order designating the zone a CREZ; and ordering the return of any remaining balance to the "defaulting" developer.¹⁷⁹

The CREZ rule includes a provision permitting the TSP to propose, as part of its CCN application, changes to the transmission improvements ordered in the CREZ that would reduce the cost of transmission or increase the amount of generating capacity that transmission improvements for the CREZ can accommodate.¹⁸⁰ The rule also contains a provision giving developers one year following completion of a CREZ transmission project (or longer, if the PUCT grants an extension) to begin taking transmission service.¹⁸¹ If the developer fails to begin taking service by the deadline, it forfeits any deposits or other form of financial commitment made to that point.¹⁸²

J. Columbia Grid

"ColumbiaGrid, a non-profit membership Washington corporation, was formed on March 31, 2006, to improve the operational efficiency, reliability, and planned expansion of the Northwest transmission grid."¹⁸³ The directors of the board are Lloyd Meyers, Shelly Richardson, and Ed Sienkiewicz. The Board's term began on August 17th.

"ColumbiaGrid will be given substantive responsibilities pursuant to a series of Functional Agreements with Members and other Qualified Non-

175. CREZ Rule, *supra* note 173, at 10,784.

176. PUBLIC UTIL. COMM'N OF TEX., RULEMAKING RELATING TO RENEWABLE ENERGY AMENDMENTS: PROJECT NO. 31852 (2006), <http://www.puc.state.tx.us/rules/rulemake/31852/31852rec.pdf>.

177. CREZ Rule, *supra* note 173, at 10,787.

178. *Id.* at 10,785.

179. CREZ Rule, *supra* note 173, at 10,796.

180. *Id.*

181. CREZ Rule, *supra* note 173, at 10,783.

182. *Id.* at 10,784.

183. ColumbiaGrid Website, <http://www.columbiagrid.org/>.

Member Parties. These agreements are being developed in a public process with broad participation.”¹⁸⁴

The current members of ColumbiaGrid are Avista Corp., BPA, Chelan County PUD, Grant County PUD, Puget Sound Energy, Seattle City Light, and Tacoma Power. All Northwest control area operators have been invited to join ColumbiaGrid as a member.

III. TRANSMISSION/INTERCONNECTION DEVELOPMENTS

A. *Promoting Transmission Investment through Pricing Reform*

Section 1241 of EAct 2005 directed the Commission to establish (no later than one year after enactment of section 219), by rule, incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce. As a result, the Commission issued a Notice of Proposed Rulemaking (NOPR)¹⁸⁵ on November 18, 2005, asking for comments on the Commission’s proposal. In the NOPR, the Commission stated that the purpose of this rulemaking is to promote greater capital investment in new transmission capacity.

On July 20, 2006, after considering the comments on the NOPR, the Commission issued its Final Rule in Order No. 679. Order No. 679 largely reflected a NOPR, with a significant change being the establishment of a rebuttable presumption that certain transmission projects—(i) those that had been approved through a regional transmission planning process or by a state siting authority, and (ii) those that were located within a Department of Energy established National Interest Electric Transmission Corridor (NIETC)—were eligible for incentives.¹⁸⁶ Also significantly, the FERC, in issuing its Final Rule, attempted to eliminate some of the confusion caused by the NOPR’s use of the term “adders.” Specifically, the Commission refused to adopt specific basis-point adders.¹⁸⁷

In the Final Rule, the Commission provided incentives for transmission infrastructure investment to help ensure the reliability of the bulk power transmission system and reduce the cost of delivered power to customers by reducing transmission congestion. The Final Rule identified specific incentives that the Commission will allow when justified in the context of individual declaratory orders or section 205 filings by public utilities under the FPA.¹⁸⁸ Among other things, the Final Rule allowed incentive rates of return on equity (ROE) for new investment by public utilities (both stand-alone transmission companies and traditional utilities), as well as a higher rate of ROE for utilities

184. *Id.*

185. Notice of Proposed Rulemaking, *Promoting Transmission Investment Through Pricing Reform*, [Regs. Preambles 2001-2005] F.E.R.C. STATS. & REGS. ¶ 32,593 (2005), 70 Fed. Reg. 71,409 (2005) (to be codified at 18 C.F.R. pt. 35).

186. Order No. 679, *Promoting Transmission Investment through Pricing Reform*, [2006 Proposed Regs.] F.E.R.C. STATS. & REGS. ¶ 31,222 at P 58 (2006), 71 Fed. Reg. 42,294 (2006) (to be codified at 18 C.F.R. pt. 35) [hereinafter Order No. 679].

187. *Id.* at P 87.

188. Order No. 679, *supra* note 186, at P 191.

that join a “transmission organization,” which did not necessarily have to be a RTO or ISO.¹⁸⁹

The Final Rule does not grant incentives to any public utility but instead permits an applicant to tailor its proposed incentives to the type of transmission investments being made and to demonstrate that its proposal meets the requirements of section 219. Further, incentives will be permitted only if the incentive package as a whole results in a just and reasonable rate. The FERC made clear, however, that “[t]he rule does not grant utilities all of the listed incentives, but rather allows utilities on a case-by-case basis to select and justify the package of incentives needed to support new investment.”¹⁹⁰ Also, in the Final Rule, the Commission agreed with comments that new transmission technologies will be adopted when they are cost effective. The Commission determined, however, that incentives will be considered for advanced technologies through the same evaluation process as other technologies.¹⁹¹

Order No. 679 also permits developers to recover 100% of prudently incurred construction work in progress (CWIP) costs, pre-commercial operation costs, and development costs when a project is abandoned for reasons beyond the developer’s control. In addition, it allows: (1) deferred cost recovery for utilities subject to retail rate caps; (2) accelerated recovery of depreciation expenses; (3) the use of “hypothetical” capital structures; and (4) an adjustment to the book value of transmission assets being sold to a transco to remove the disincentive associated with the impact of accelerated depreciation on federal capital gains tax liabilities.¹⁹² Under the Final Rule, transmission owners will also be permitted to recover costs necessary to comply with mandatory reliability standards or to facilitate infrastructure development in NIETCs.

The Final Rule also establishes a new annual reporting requirement: FERC Form-730 will apply to all utilities receiving incentive rate treatment for specific transmission projects.

Pursuant to Order No. 679, parties seeking incentives may do so in one of two ways; they may submit either (1) a petition for a declaratory order, followed by a subsequent FPA section 205 filing, or (2) a section 205 filing alone.¹⁹³ The declaratory order/section 205 filing combination can be a “valuable tool” because it allows an applicant to obtain an order indicating that its proposed facility qualifies for incentive-based rates prior to making a formal section 205 filing and actually constructing the facility, which can facilitate financing and investment in new facilities. Once a declaratory order has been issued and the facilities have been constructed, the transmission provider would then be responsible for making the appropriate section 205 filing before the incentive rates could become effective. Either way, however, the applicants for ROE incentives must demonstrate that: (1) their facilities either ensure reliability or

189. *Id.* at P 234.

190. Press Release, Federal Energy Regulatory Commission, Final rule promoting transmission investment adopted; rate incentives for two transmission proposals accepted (July 20, 2006), *available at* <http://www.ferc.gov/press-room/press-releases/2006/2006-3/07-20-06-E-3.asp>.

191. Order No. 679, *supra* note 186, at P 288.

192. *Id.* at PP 230-47.

193. Order No. 679, *supra* note 186, at P 76.

reduce the cost of delivered power by reducing transmission congestion; (2) a nexus exists between the incentive sought and the investment being made; and (3) the resulting rates are just and reasonable.¹⁹⁴

In response to the Final Rule, a number of parties submitted requests for rehearing and/or clarification. The FERC granted a rehearing on September 19, 2006. The order on rehearing, Order No. 679-A, was issued on December 21, 2006. The Order 679-A revises the regulatory text in Order No. 679. It clarifies that in order to create a rebuttable presumption that an applicant meets the Federal Power Act section 219 qualifications for incentive rate treatment, an applicant must explain whether the processes relied upon: (i) regional planning, (ii) state siting approvals, or (iii) include a determination that the project is necessary to ensure reliability or reduce congestion.¹⁹⁵ The Order 679-A clarifies that applicants must demonstrate that the total package of incentives is tailored to the obvious risks or challenges faced by the applicant in undertaking the project. With respect to the incentive ROE, this order clarifies that each applicant must justify a higher ROE under the total package of incentives, and show a nexus between the incentives requested and the proposed project, and justify where in the zone of reasonableness the ROE should lie. Order 679-A also clarifies that applicants can request a specific ROE determination in a petition for declaratory order, thereby providing upfront certainty before investments are made.¹⁹⁶

B. Generation Interconnection

1. Large Generators – Order No. 2003-C

The D.C. Circuit Court of Appeals, in an order issued on January 12, 2007, rejected appeals of FERC Order No. 2003 and its rehearing orders, and affirmed the FERC's decisions on large generator interconnections in all respects.¹⁹⁷ The court reviewed claims by two sets of petitioners, one comprised of four utilities, and one of six state regulatory agencies. The petitioners claimed that Order No. 2003 and its sequels were arbitrary and capricious, and also exceeded the FERC's statutory mandate.

The court found that section 201 of the Federal Power Act provided the FERC with sufficient authority to regulate the relationship between a utility providing interconnection service and the customer. The court also rejected the arguments that Order No. 2003 inappropriately extended its regulatory scheme to facilities jointly-owned by a jurisdictional and a non-jurisdictional utility.¹⁹⁸ The court concluded that the resolution of jointly-owned facilities in Order No. 2003 was very similar to the arrangement that the court found permissible in its review

194. *Id.*

195. Order No. 679-A, *Promoting Transmission Investment through Pricing Reform*, [2007 Proposed Regs.] F.E.R.C. STATS. & REGS. ¶ 31,236 at P 41 (2007), 72 Fed. Reg. 1152 (2007) (to be codified at 18 C.F.R. pt. 35).

196. *Id.* at P 7.

197. National Ass'n of Regulatory Util. Comm'r v. FERC, No. 04-1148, 2007 WL 79054 (D.C. Cir. Jan. 12, 2007).

198. *National Ass'n of Regulatory Util. Comm'r*, 2007 WL 79054, at *2.

of Order No. 888 with respect to open-access transmission service over lines owned jointly by jurisdictional and non-jurisdictional utilities. Finally, the court rejected the governmental petitioners' claim that the FERC erred in not applying the seven factor test, established in Order No. 888, to determine whether a particular facility is an exempt local distribution facility that should not be subjected to the interconnection rules.¹⁹⁹ Instead, the court concluded that the interconnection rules governed the service of interconnection, not the underlying facility *per se*.

The court also rejected petitioners' arguments that Order No. 2003 and its progeny impermissibly impinged on utilities' exercise of eminent domain.²⁰⁰ Order No. 2003-A proscribed utilities from discriminating in their exercise of eminent domain powers to the detriment of independent generators. Finally, the court rejected petitioners' claim that the "At or Beyond" rule established in Order No. 2003 was unsupported.²⁰¹

2. Small Generators – Order No. 2006-B

The Commission issued an Order on Clarification of its Order No. 2006-A in July 2006.²⁰² Order No. 2006-B addressed one discrete issue, and clarified that the *pro forma* small generator interconnection procedures study agreements should contain certain miscellaneous boilerplate contract provisions. The boilerplate provisions address issues such as governing law, amendment, third-party beneficiaries, waiver, multiple counterparts, partnership, and severability.

C. Backstop Siting Authority (National Corridors)

Section 1221 of EAct 2005 adds a new section 216 to the Federal Power Act (FPA), providing for Federal siting of electric transmission facilities under certain circumstances. New FPA section 216 requires that the Secretary of the Department of Energy (DOE or Secretary) identify transmission constraints. It mandates that the Secretary conduct a study of electric transmission congestion within one year of enactment and every three years thereafter, and that the Secretary then issue a report. The Secretary is further empowered to designate certain constrained areas as national interest electric transmission corridors (NIETCs).

The FPA section 216(b) provides that the FERC may issue permits to construct or modify electric transmission facilities in a NIETC under certain circumstances. The FERC has the authority to issue permits to construct or modify electric transmission facilities if it finds that: (1) a state in which such facilities are located does not have the authority to approve the siting of the facilities or to consider the interstate benefits expected to be achieved by the construction or modification of the facilities; (2) the applicant is a transmitting utility, but does not qualify to apply for siting approval in the state because the

199. *Id.* at *4.

200. *National Ass'n of Regulatory Util. Comm'r*, 2007 WL 79054, at *8-11. (Sentelle, J., dissenting).

201. *Id.* at *6.

202. Order No. 2006-B, *Standardization of Small Generator Interconnection Agreements and Procedures*, [2006 Proposed Regs.] F.E.R.C. STATS. & REGS. ¶ 31,221 (2006), 71 Fed. Reg. 42,587 (2006) (to be codified at 18 C.F.R. pt. 35).

applicant does not serve end-use customers in the state; or (3) the state commission or entity with siting authority withholds approval of the facilities for more than one year after an application is filed, or one year after the designation of the relevant national interest electric transmission corridor, whichever is later, or the state conditions the construction or modification of the facilities in such a manner that the proposal will not significantly reduce transmission congestion in interstate commerce or is not economically feasible.²⁰³

New FPA section 216(h)(2) designates the DOE as lead agency to coordinate all federal authorizations needed to construct proposed electric transmission facilities in National Corridors. Under FPA section 216(h)(4)(A), to ensure timely efficient reviews and permit decisions, the DOE is required to establish prompt and binding intermediate milestones and ultimate deadlines for all federal reviews and authorizations required for a proposed electric transmission facility.²⁰⁴ Section 216(h)(5)(A) of the FPA requires that DOE as lead agency, in consultation with the other affected agencies, prepare a single environmental review document that would be used as the basis for all decisions for the proposed projects under federal law.²⁰⁵

On May 16, 2006, the Secretary delegated paragraphs (2), (3), (4)(A)–(B), and (5) of FPA section 216(h) to the FERC as they apply to proposed facilities in designated NIETCs for which an application for authority to construct has been submitted to the FERC.²⁰⁶

On June 16, 2006, the FERC issued a Notice of Proposed Rulemaking (NOPR) in the “Regulations for filing Applications for Permits to Site Interstate Electric Transmission Facilities” proceeding.²⁰⁷

On August 8, 2006, the DOE issued its National Electric Transmission Congestion Study that examined transmission congestion and constraints and identified affected transmission paths in many areas of the nation.²⁰⁸ Also, on August 8, 2006, several federal agencies including the DOE and the FERC entered into a Memorandum of Understanding on Early Coordination of Federal Authorization and Related Environmental Reviews Required in Order to Site Electric Transmission Facilities (MOU).²⁰⁹ The comment period on congestion

203. Under FPA section 216(i)(4), the Commission may not issue a permit for facilities within a State that is a party to an interstate compact establishing a regional transmission siting agency unless the members of the compact are in disagreement and the Secretary of the Department of Energy makes certain findings. Energy Policy Act of 2005, Pub. L. No. 109-58, § 1221, 119 Stat. 594.

204. Under FPA section 216(h)(6)(A), if any agency has denied a Federal authorization required for a transmission facility, or has failed to act by the deadline established by the Secretary, the applicant or any State in which the facility would be located may file an appeal with the President. *Id.* § 1221.

205. Energy Policy Act of 2005 § 1221.

206. U.S. DEP'T OF ENERGY, DELEGATION ORDER NO. 00-004.00A (2006), http://www.directives.doe.gov/pdfs/sdoa/00-004_00A.pdf.

207. *Regulations for Filing Applications for Permits to Site Interstate Elec. Transmission Facilities*, 115 F.E.R.C. ¶ 61,334 (2006).

208. U.S. DEP'T OF ENERGY, NAT'L ELEC. TRANSMISSION CONGESTION STUDY: EXECUTIVE SUMMARY (2006), http://www.oe.energy.gov/DocumentsandMedia/NETC_ExSum_8Aug08.pdf.

209. The other agencies include the Department of Defense, the Department of Agriculture, the Department of the Interior, the Department of Commerce, the Environmental Protection Agency, the Council on Environmental Quality, and the Advisory Council on Historic Preservation.

study was closed on October 10, 2006. As of December 31, 2006, the DOE has not designated NIETCs.

On November 16, 2006, the FERC adopted a Final Rule, Order No. 689, laying out the filing requirements and procedures for parties seeking to have the FERC use its backup authority to approve the siting of transmission facilities in areas designated as NIETCs by the DOE.²¹⁰

The biggest change from the NOPR relates to the initiation of pre-filing at the Commission. Under the proposed rule, an applicant was barred from making a formal application for a federal construction permit until one year after initiation of a state proceeding. But pre-filing could be initiated earlier, and could overlap with the state siting proceeding. In response to state concerns, the Final Rule bars both a formal application and the initiation of pre-filing within one year of initiation of a state proceeding.²¹¹

A proposal to build or expand electric transmission facilities must: apply to facilities that will be used for transmission in interstate commerce; be consistent with the public interest and enhance energy independence; significantly reduce transmission congestion in interstate commerce and protect or benefit consumers; be consistent with national energy policy and enhance energy infrastructure; and maximize, to the extent reasonable and practicable, existing towers or structures.²¹²

The rule encourages maximum participation from all interested stakeholders through a Public Participation Plan and an extensive pre-application and post-application process. The participation plan provides all interested parties, including affected landowners, with information on all aspects of the proposed project, including national and local benefits and environmental impacts. The participation plan provides for public involvement during the pre-filing and application processes, and must be accessible in a central location in each county through which the proposed project would be located.

The pre-filing process includes consultation with the Director of the Office of Energy Projects (OEP) to determine a project's eligibility for pre-filing, the start of environmental review under the National Environmental Policy Act, numerous public participation opportunities, and a determination by the Director of OEP that an application is ready to be filed for Commission consideration.

Once an application is filed, the rule requires public notification of the application, issuance and solicitation of comments on the draft environmental document, preparation and issuance of a final environmental document, a review of the record, and issuance of a final decision by the Commission.

By the end of 2006 DOE has not designated NIETCs.

210. Order No. 689, *Regulations for Filing Applications for Permits to Site Interstate Elec. Transmission Facilities*, [2006 Proposed Regs.] F.E.R.C. STATS. & REGS. ¶ 31,234 (2006), 71 Fed. Reg. 69,440 (2006) (to be codified at 18 C.F.R. pts. 50, 380).

211. TRANSMISSION & DISTRIB. WORLD, FERC FINALIZES ELEC. TRANSMISSION SITING RULE (2006), available at <http://tdworld.com/news/ferc-transmission-siting-rule/>.

212. *Id.*

IV. RELIABILITY

A. *Electric Reliability*

During 2006 the Commission took major steps to implement its new reliability jurisdiction conferred by section 215 of the FPA.²¹³

1. FERC Rulemaking to Implement Reliability Legislation

On February 3, 2006, the FERC issued Order No. 672, *Rules Concerning Certification of the Electric Reliability Organization*,²¹⁴ its Final Rule implementing new section 215, thereby putting in place the framework for creating, authorizing, and overseeing a non-governmental electric reliability organization (ERO) and generally addressing reliability issues within the United States. Much of the detail in the regulations was derived from the statutory provisions, with specific procedures or regulatory requirements added in certain areas.

The new regulations define the terms “Bulk-Power System,” “Reliable Operation,” “Reliability Standard,” and “Transmission Organization.”²¹⁵ Additional definitions were left to the anticipated ERO certification proceeding or to reliability standards to be considered after the ERO was certified.

The Commission described its jurisdiction and the applicability of the rules of the ERO, the Commission’s regulations, and reliability standards made effective under the Act.²¹⁶ The rules, regulations, and reliability standards apply to all users, owners, and operators of the bulk power system, including entities such as municipal systems, rural electric cooperatives, federal power marketing administrations, and entities within the ERCOT, regardless of their jurisdictional status under other sections of the FPA. Section 39.2 requires users, owners, and operators to register with the ERO and applicable regional entities and supply information necessary to implement section 215 of the FPA.

The Commission established the criteria an ERO applicant must meet for certification.²¹⁷ The Commission dropped the proposal made in the notice of proposed rulemaking²¹⁸ to require periodic recertification of the ERO and substituted a requirement that the ERO submit a detailed assessment of its performance and the performance of regional reliability entities three years after certification and at five-year intervals thereafter. The Commission will then

213. Energy Policy Act of 2005, Title XII, Subtitle A (to be codified at 16 U.S.C. § 824o).

214. Order No. 672, *Rules Concerning Certification of the Elec. Reliability Org.; and Procedures for the Establishment, Approval, and Enforcement of Elec. Reliability Standards*, [2006 Proposed Regs.] F.E.R.C. STATS. & REGS. ¶ 31,204 (2006), 71 Fed. Reg. 8662 (2006) (to be codified at 18 C.F.R. pt. 39), *order on reh’g*, Order No. 672-A, 114 F.E.R.C. ¶ 61,328 (2006) [hereinafter Order No. 672].

215. 18 C.F.R. § 39.1 (2006).

216. *Id.* § 39.2.

217. 18 C.F.R. § 39.3.

218. Less than a month after the Energy Policy Act of 2005 was enacted, on September 1, 2005, the FERC issued the Notice of Proposed Rulemaking to implement the provisions of new FPA section 215. *Rules Concerning Certification of the Elec. Reliability Org.; and Procedures for the Establishment, Approval, and Enforcement of Elec. Reliability Standards*, 112 F.E.R.C. ¶ 61,239 (2005).

institute a proceeding to evaluate the assessment and require any modifications to the ERO and regional entity programs and procedures considered necessary.

The Commission established a framework for funding the ERO and the regional entities.²¹⁹ The ERO must submit its budget and the budgets of the regional entities for “statutory activities,”²²⁰ along with a formula or method for allocating, assessing, and collecting such charges, 130 days prior to the beginning of a fiscal year. The Commission committed to acting on the filing no later than sixty days prior to the beginning of the ERO’s fiscal year. The regulation obligates all entities subject to the Commission’s reliability jurisdiction to pay all ERO assessments approved by the Commission. The Commission found that funding based on net energy for load is one “fair, reasonable, and uncomplicated method” for allocating funding, but did not rule out other alternatives.²²¹

No reliability standard may take effect until the Commission has approved it, by rule or order, after notice and an opportunity for public hearing.²²² The Commission will approve a reliability standard that is just, reasonable, not unduly discriminatory or preferential, and in the public interest. A reliability standard proposed by an Interconnection-wide regional entity will be rebuttably presumed to meet that test. The Commission may remand a proposed reliability standard to the ERO, or direct the ERO to make changes in a reliability standard, but the Commission itself cannot re-write a reliability standard. The regulations include a mechanism for addressing conflicts between a reliability standard and a rule, order, tariff, or agreement approved by the Commission that is applicable to a Transmission Organization.²²³

The regulations establish requirements regarding ERO and regional entity enforcement programs for reliability standards, including requirements for the ERO to report violations and alleged violations to the Commission.²²⁴ Investigations and proceedings involving alleged violations are to be non-public until they are resolved or the ERO files a notice of penalty with the Commission. Affected parties may seek review of ERO determinations by the Commission. The Commission has independent enforcement authority under section 215 over all users, owners, and operators of the bulk-power system.

The regulations authorize the ERO to delegate enforcement authority to regional entities through agreements subject to approval by the Commission after notice and an opportunity for comment.²²⁵ A regional entity must generally meet the same requirements as the ERO to be eligible for a delegation, except the regional entity has more flexibility with regard to its governance structure. A proposed delegation agreement with a regional entity established on an

219. 18 C.F.R. § 39.4 (2006).

220. Statutory activities generally are the development of Reliability Standards and their enforcement, and monitoring of Bulk Power System reliability. See Order No. 672, *supra* note 214, at P 202, and discussion *infra*.

221. Order No. 672, *supra* note 214, at P 35.

222. 18 C.F.R. § 39.5 (2006).

223. *Id.* § 39.6.

224. 18 C.F.R. § 39.7.

225. *Id.* § 39.8.

Interconnection-wide basis is rebuttably presumed to provide for the effective and efficient administration of reliability.

The Commission has authority over the ERO and regional entities for enforcement of Commission rules and orders, including the possible suspension or rescission of the ERO's certification.²²⁶ The ERO must file changes to its rules of procedure, as well as changes to the rules of procedure of the regional entities, for approval by the Commission.²²⁷

The Commission directed the ERO to periodically assess the reliability and adequacy of the bulk power system and file reports with the Commission, the Secretary of Energy, regional advisory bodies, and regional entities.²²⁸

As directed by section 215, the regulations include a mechanism for dealing with conflicts between reliability standards and actions by states.²²⁹ The regulations also include a provision for establishing regional advisory bodies to advise both the ERO and the Commission on matters including Reliability Standards proposed to be applicable within a region.²³⁰

B. Certification of the Electric Reliability Organization

On July 20, 2006, the Commission conditionally certified the North American Electric Reliability Corporation (NERC)²³¹ as the ERO under section 215.²³² The Commission generally approved the NERC's governance, which includes an independent board of trustees with proportional representation from Canada, and a sector-based member representatives committee. It also by and large approved the NERC's proposal for funding and its standards development procedure through a consensus-based process. The Commission also approved the NERC's proposal to carry out its main compliance and enforcement efforts through delegation to regional entities, but stressed the need for uniformity in the regional programs and consistency in implementation. The Commission required the NERC to make a number of changes to its governance, rules of procedure, proposed *pro forma* regional delegation agreement, and compliance enforcement program. In response to these directions, the NERC made three compliance filings.

226. 18 C.F.R. § 39.9.

227. *Id.* § 39.10.

228. 18 C.F.R. § 39.11 (2006). Consistent with this requirement, the North American Electric Reliability Council filed its 2006 Long-Term Reliability Assessment with the Commission on October 16, 2006.

229. *Id.* § 39.12.

230. 18 C.F.R. § 39.13.

231. The North American Electric Reliability Corporation (NERC Corporation) is an affiliate of the North American Electric Reliability Council (NERC Council) and was formed for the purpose of becoming the ERO. The NERC Council was a voluntary industry organization formed after the 1965 blackout in the Northeast and Canada to improve coordination of interconnected operations of electric utilities. Effective January 1, 2007, the NERC Council and the NERC Corporation merged, with the NERC Corporation being the surviving corporation (together NERC). The NERC filed an application for certification as the ERO with the FERC in April 2006.

232. *North Am. Elec. Reliability Corp.*, 116 F.E.R.C. ¶ 61,062 (2006), *order on reh'g*, 117 F.E.R.C. ¶ 61,126 (2006), *appeal pending sub nom. Alcoa v. FERC*, Docket No. 06-1426 (D.C. Cir. filed Dec. 29, 2006) [hereinafter Certification Order].

On October 30, 2006, the Commission acted on the NERC's first compliance filing making the changes to its bylaws required by the ERO Certification Order. The same order addressed petitions for rehearing of the Certification Order.²³³ The Commission largely denied rehearing of the Certification Order and accepted the NERC's compliance filing and revised bylaws, including the NERC's proposal to have different voting models for its registered ballot body (which votes on reliability standards) and its member representatives committee (which votes on governance matters and provides advice to the NERC board of trustees). The Commission required the NERC to make a further compliance filing regarding voting in committees and subgroups.

On October 18, 2006, the NERC made its second compliance filing on the non-governance issues the Commission directed in the Certification Order.²³⁴ As permitted in the Certification Order, the NERC deferred making the compliance filing dealing with its *pro forma* delegation agreement and the regional delegation agreements.

C. Approval of Regional Advisory Body

At the same time it issued the Certification Order, the Commission approved a petition to establish the Western Interconnection Regional Advisory Board (WIRAB), as the first regional advisory body authorized under FPA section 215(j).²³⁵ The WIRAB comprises one representative appointed by the governor of each of the participating states, and its purpose is to provide advice to a regional entity established within the Western Interconnection, the ERO, and the Commission on the governance of the regional entity, on reliability standards to be applicable within the Western Interconnection, and on fees to be assessed within the region. The WIRAB also may include participation by representatives of agencies, states, and provinces outside the United States. The Commission approved in principle to the payment of reasonable costs incurred by a regional advisory body in performing section 215(j) activities from mandatory fees collected under section 215 and directed that the NERC include such costs and appropriate support as part of its budget.

D. Approval of 2007 Business Plan and Budget for ERO and Regional Entities

On October 24, 2006, the Commission approved the NERC's 2007 business plan and budget as well as the 2007 budgets for the intended regional entities to carry out their delegated activities under section 215.²³⁶ The order also approved the NERC's proposed assessments (which reflect an allocation between the U.S. and Canada based on proportionate net-energy-for-load) to collect the NERC and regional entity costs and authorized the NERC to send invoices to identified

233. *North Am. Elec. Reliability Corp.*, 117 F.E.R.C. ¶ 61,126 (2006).

234. *North Am. Elec. Reliability Corp.*, 118 F.E.R.C. ¶ 61,030 (2007). The Commission has scheduled action on the compliance filing for its January 2007 meeting.

235. *Governors of Ariz., Cal., Colo., Mont., Nev., N. M., Or., Utah, Wash. and Wyo.*, 116 F.E.R.C. ¶ 61,061 (2006) [hereinafter WIRAB Order].

236. *North Am. Elec. Reliability Corp.*, 117 F.E.R.C. ¶ 61,091 (2006).

entities on December 1, 2006, to permit the NERC to fund its 2007 operations and the operations of the intended regional entities.²³⁷

One important issue concerned the scope of the activities that could be funded under the statutory mechanism. The Commission stated that anything required of the ERO or a regional entity by the statute, by Order No. 672 pursuant to the statute, or by any subsequent Commission order pursuant to section 215 was within the scope of the funding provisions of the statute.²³⁸ The Commission ruled the following major program elements were properly funded under the statute: (1) development of reliability standards; (2) compliance enforcement and organization registration and certification; (3) reliability readiness audits and improvement; (4) training, education, and operator certification; (5) reliability assessment and performance analysis; (6) situational awareness and infrastructure security; and (7) administrative services. The Commission also ruled the scope of the regional entity budgets should be consistent with the NERC budget.²³⁹

The Commission decided that the Western Electricity Coordinating Council (WECC) could not include the costs of its reliability coordinators within the statutory funding mechanism. The Commission stated that the reliability coordinators were involved in real-time operations and that funds collected under the authority of section 215 should be used for statutory responsibilities such as developing and enforcing reliability standards, not implementing reliability standards.²⁴⁰ The WECC and others sought rehearing on this issue. The Commission did approve the inclusion of funds to support the WIRAB, with those costs to be allocated among the entities in the Western Interconnection.

Finally, the Commission required the NERC to file additional information on its accounting and recordkeeping and directed that the NERC and the regional entities follow a consistent and uniform approach to their 2008 budget submissions.

E. FERC Rulemaking to Approve Proposed Reliability Standards

On October 20, 2006, the Commission issued a notice of proposed rulemaking that would make eighty-three of the NERC's proposed reliability standards mandatory and enforceable within the United States by June 2007.²⁴¹ The Commission also proposed to exercise its authority under section 215(d)(5) to direct the NERC to make a number of improvements in sixty-two of the standards, once they take effect. The Commission proposed that an additional twenty-four standards (which generally cover matters subject to criteria adopted

237. *Id.* at P 6.

238. 117 F.E.R.C. ¶ 61,091 at P 28.

239. *Id.* at PP 31-39.

240. 117 F.E.R.C. ¶ 61,091 at P 53.

241. *Mandatory Reliability Standards for the Bulk Power Sys.*, [2006 Proposed Regs.] 117 F.E.R.C. STATS. & REGS. ¶ 32,608 (2006), 71 Fed. Reg. 64,770 (2006) (to be codified at 18 C.F.R. pt. 40) [hereinafter Standards NOPR]. In conjunction with its April 2006 filing for certification as the ERO, the NERC submitted 102 reliability standards for FERC approval. Shortly thereafter, the FERC announced that it would conduct a rulemaking to approve the mandatory reliability standards. Prior to issuing the notice of proposed rulemaking, the FERC issued a staff preliminary assessment of the reliability standards in May and took comments on the staff analysis. *Id.* at P 4.

by regional reliability organizations), would remain pending at the FERC until the receipt of additional information from the NERC.²⁴² Until the Commission takes further action on those twenty-four standards, utilities would be directed to continue to follow them as a part of “good utility practice.” The Commission did not propose to remand any standards. The FERC would require the NERC to focus its resources on modifying standards that have the largest impact on near-term bulk power system reliability, giving a high priority to proposed modifications that reflect recommendations contained in the report on the August 2003 blackout.²⁴³ The Commission did not propose to adopt the NERC’s suggestion of a six-month trial period during which penalties would not be assessed.

The mandatory reliability standards will apply to “users, owners, and operators” of the bulk power system. The Commission noted that “bulk power system” is one aspect of defining the scope of its jurisdiction under section 215 and proposed to interpret that term more expansively than the NERC’s traditional definition of “bulk electric system.”²⁴⁴ The Commission did not propose to define the term “user of the bulk power system” on a generic basis, but instead to determine applicability on a standard-by-standard basis.²⁴⁵ The Commission proposed to use the NERC functional model to identify the entities to which each reliability standard applies, and declined to exempt entities below a threshold level from compliance with all reliability standards, because there may be instances where a small entity’s compliance is critical to reliability.

The Commission noted that “bulk power system” is one aspect of defining the scope of its jurisdiction under section 215 and proposes to interpret that term more expansively than the NERC’s traditional definition of “bulk electric system.”²⁴⁶

The Commission proposed that the NERC focus its resources on modifying standards that have the largest impact on near-term bulk power system reliability, giving a high priority to proposed modifications that reflect Blackout Report recommendations.

The Standard NOPR contains a discussion of each standard proposed to be made effective, with additional details on the modifications the Commission proposed to direct the NERC to make, once the standards become effective. Comments on the proposed standards were due on January 3, 2007.

242. The NERC also filed eight standards dealing with cyber security matters (which the Commission docketed separately as Mandatory Reliability Standards for Critical Infrastructure Protection, Docket No. RM06-22-000) and three standards dealing with facilities (which the Commission docketed separately as Facilities Design, Connections and Maintenance Reliability Standards, Docket No. RM07-3-000). Separate notices of proposed rulemaking to adopt these standards will be issued.

243. 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), <https://reports.energy.gov/B-F-Web-Part1.pdf>.

244. Standards NOPR, *supra* note 241, at P 68.

245. *Id.* at P 43.

246. Standards NOPR, *supra* note 241, at P 68.

F. *Agreements Delegating Authority to Regional Entities*

In the Certification Order, the Commission directed the NERC to make a number of revisions in the *pro forma* delegation agreement and to develop, with the regions, a uniform set of compliance and enforcement procedures with substantially greater detail than was included in the NERC's ERO certification application.²⁴⁷ The Commission required that the greater detail and uniformity be reflected in the individual delegation agreements that the NERC negotiates with the regions.²⁴⁸ On November 29, 2006, the NERC filed a revised *pro forma* delegation agreement in compliance with the Certification Order²⁴⁹ and proposed delegation agreements with seven regional reliability organizations.²⁵⁰ On December 21, 2006, the NERC filed a request to approve a delegation agreement with the Florida Reliability Coordinating Council.²⁵¹ Comments on the filings were due on January 10, 2007.

G. *Recognition in Canada*

In recognition of the international nature of the North American bulk-power system, at the same time that the NERC filed its application for certification as the ERO with the FERC, the NERC made filings with the appropriate provincial authorities in eight Canadian provinces for recognition as the ERO and for recognition/approval of reliability standards. The NERC also made a filing with the National Energy Board of Canada, which has jurisdiction over international power lines between the U.S. and Canada, for recognition as the ERO and for recognition of reliability standards. On September 15, 2006, the National Energy Board signed a Memorandum of Understanding with the NERC that recognizes the NERC as the ERO.²⁵² On October 24, 2006, the Ontario Energy Board signed a Memorandum of Understanding with the NERC that describes how reliability standards are made mandatory and enforceable in Ontario and how the NERC will coordinate with authorities in Ontario. On December 9, 2006, the Québec Régie de l'énergie signed a Memorandum of Understanding with the NERC that describes how the NERC and the Régie will work to achieve mandatory and enforceable reliability standards within Québec. On December 22, 2006, the Nova Scotia Utilities and Appeal Board signed a Memorandum of Understanding with the NERC detailing how reliability standards would be made mandatory and how they would be enforced within Nova Scotia. Discussions with the remaining provinces are ongoing.

247. Certification Order, *supra* note 232, at P 350.

248. *Id.* at P 518.

249. U.S. DEP'T OF ENERGY, NOTICE OF FILINGS (2006), available at <http://a257.g.akamaitech.net/7/257/2422/01jan20061800/edocket.access.gpo.gov/2006/E6-21047.htm>.

250. Texas Regional Entity, a division of the Elec. Reliability Council of Tex. (Docket No. RR07-1-000); Midwest Reliability Org. (Docket No. RR07-2-000); Ne. Power Coordinating Council: Cross Border Regional Entity (Docket No. RR07-3-000); Reliability First Corp. (Docket No. RR07-4-000); SERC Reliability Corp. (Docket No. RR07-5-000); Sw. Power Pool, Inc. (Docket No. RR07-6-000); W. Elec. Coordinating Council (Docket No. RR07-7-000). *Id.*

251. U.S. DEP'T OF ENERGY, NOTICE OF FILINGS (2006), available at <http://a257.g.akamaitech.net/7/257/2422/01jan20061800/edocket.access.gpo.gov/2006/E6-21047.htm>.

252. ALEXANDER'S GAS & OIL CONNECTIONS, NAT'L ENERGY BD. RECOGNIZES NERC AS ELEC. RELIABILITY ORG. (2006), available at <http://www.gasandoil.com/goc/news/ntn64110.htm>.

V. MARKET BASED RATE DEVELOPMENTS

A. *Commission Issues NOPR to Codify Market Power Test*

On May 18, 2006, the Commission issued a NOPR to codify its case-by-case review and approval of market-based rate authorizations. Up to now, the Commission has traditionally used a four-prong analysis to measure market power focused on: (1) generation market power; (2) transmission market power; (3) other barriers to entry; and (4) affiliate abuse.

The NOPR proposes to amend this four-prong approach into a two-prong test: (1) horizontal market power and (2) vertical market power. In essence, the NOPR proposes that the existing generation market power prong would become the horizontal market prong, and the existing prongs of transmission market power and other barriers to entry together would become the vertical market power prong. The Commission proposes to convert the affiliate abuse prong into conditions of authorization, rather than a discrete measure of market power. That is, applicants would have to demonstrate that they comply with the Commission's affiliate sales restrictions in order to be authorized to transact at market-based rates.

The NOPR proposes the following changes to the existing market-based rate regime:

- New-construction generation (post 1996 construction) would no longer be exempted from the market-power analysis;
- The native-load proxy for market power screens would be changed from the minimum peak day in the season to the average peak native load;
- The Delivered Price Test would be retained for companies failing the initial market-power screens;
- Maintaining an OATT would mitigate any vertical market power;
- Violations of the OATT may be grounds for revocation of market-based rate authority;
- Certain small power sellers (sellers that own or control 500 MW or less of generating capacity in aggregate and that are not affiliated with a public utility with a franchised service territory) would be exempt from filing a triennial review;
- Other holders of market-based rate authority would file triennial reviews on a scheduled organized by regions;
- All sellers at market-based rates would be required to file change in status reports; and
- Corporate entities would have a single, consolidated market-based rate tariff.

B. Mitigation Proposals

The Commission accepted a number of filed mitigation proposals that were conditionally accepted by the Commission.²⁵³ In *MidAmerican Energy Co.*, however, the Commission rejected, in part, the mitigation proposed by MidAmerican by rejecting MidAmerican's proposal to make sales at market-based rates within its control area for sales that sink outside the control area.²⁵⁴ On August 1, 2005, MidAmerican filed a mitigation proposal in response to the Commission's order of June 1, 2005, finding that MidAmerican had market-power within its control area.²⁵⁵ In that mitigation proposal, MidAmerican sought permission to make sales at market-based rates within its control area for sales that sink outside the control area. The Commission rejected MidAmerican's proposal.

The Commission stated that:

MidAmerican's proposed tariff language would improperly limit mitigation to certain customers in the MidAmerican control area, namely, only to sales to those buyers that serve end-use customers in the MidAmerican control area. MidAmerican's proposal would improperly allow it to make market-based rate sales within its control area (where it has the presumption of market power) to any entities that do not serve end-use customers in the MidAmerican control area. Such a limitation would not mitigate MidAmerican's ability to attempt to exercise market power over sales in its control area.²⁵⁶

C. Ninth Circuit Decision in *Snohomish*

On December 19, 2006, the U.S. Court of Appeals for the Ninth Circuit issued opinions in *Public Utility District No. 1 of Snohomish County, Washington v. FERC*,²⁵⁷ and *Public Utilities Commission of the State of California v. FERC*,²⁵⁸ which concerned separate appeals of FERC orders rejecting unilateral attempts to modify forward market-based rate contracts entered into by power companies during the western energy crisis of 2000-01. In the companion cases, the Ninth Circuit explained that there are three prerequisites to the *Mobile-Sierra* standard of review: 1) the absence of a clause that allows for unilateral modification of the contract; 2) the Commission must have timely and effective review of the market-based rates in the contracts; and 3) the Commission must engage in meaningful review of the circumstances of the formation of the contract—e.g., was the marketplace functional and competitive.²⁵⁹ The Ninth Circuit then enunciated a new standard of *Mobile-Sierra* review applicable to a “high-rate” challenge, holding that the relevant

253. See *South Car. Elec. & Gas Co.*, 114 F.E.R.C. ¶ 61,143 (2006); *Okla. Gas & Elec. Co.*, 114 F.E.R.C. ¶ 61,297 (2006).

254. *MidAmerican Energy Co.*, 114 F.E.R.C. ¶ 61,280 (2006) [hereinafter *March 17 MidAmerican Order*].

255. *MidAmerican Energy Co.*, 111 F.E.R.C. ¶ 61,320 (2005) [hereinafter *June 1 MidAmerican Order*].

256. *March 17 MidAmerican Order*, *supra* note 254, at P 31.

257. *Public Util. Dist. No. 1 of Snohomish Cty., Wash. v. FERC*, 471 F.3d 1053 (9th Cir. 2006).

258. *Public Utils. Comm. of the State of Cal. v. FERC*, 474 F.3d 587 (9th Cir. 2006).

259. *Snohomish County*, at 1075-77.

inquiry was whether the contract is outside of the zone of reasonableness and results in retail rates that are higher than if the zone were not exceeded.²⁶⁰

The *CPUC* decision made consistent findings. In addition, the court directed the FERC to consider the FERC staff report on market manipulation and market manipulation discovery.

Together, these cases call into question whether market-based rate contracts can get *Mobile-Sierra's* public interest standard of review, based upon the Commission's existing market-based rate regime.

VI. CORPORATE AND AFFILIATE

In April, on rehearing the FERC largely affirmed Order No. 667,²⁶¹ which had been adopted in December 2005 to implement the PUHCA 2005 and which required public utility holding companies and centralized service companies to file reports, follow specified accounting and record-retention regulations, and make available their records and books. In Order No. 667-A, the FERC sought to harmonize discrepancies between the PUHCA 2005 regulations adopted in Order No. 667 with the section 203 regulations, which had been amended by Order No. 669 governing mergers, acquisitions, and dispositions of jurisdictional assets.

Specifically, in Order No. 667-A, among other things the FERC: (a) affirmed its determination that persons that own only exempt wholesale generators (EWGs), qualifying facilities (QFs), or foreign utility companies (FUCOs) are public utility holding companies;²⁶² (b) held that persons that are holding companies solely by virtue of owning EWGs, QFs, or FUCOs are "automatically exempt" from the PUHCA 2005 regulations;²⁶³ (c) added a new requirement that persons with a waiver or exemption must notify the FERC if facts or circumstances change;²⁶⁴ and (d) added a new requirement that centralized holding-company service companies not already required to file Form No. 60 annually must file a Form No. 61 narrative description of their functions.²⁶⁵

In July, in Order No. 667-B, the FERC largely reaffirmed Order No. 667-A, but provided several clarifications concerning FUCO status (holding that state commission certification is not required to obtain FUCO status),²⁶⁶ the definition of "single state holding-company system" (clarifying that revenues derived from EWGs, FUCOs, and QFs will not be considered "public-utility company"

260. *Id.* at 1088-90.

261. Order No. 667, *Repeal of the Pub. Util. Holding Co. Act of 1935 and Enactment of the Pub. Util. Holding Co. Act of 2005*, [Regs. Preambles 2001-2005] F.E.R.C. STATS. & REGS. ¶ 31,197 (2005), 70 Fed. Reg. 75,592 (2005) (to be codified at 18 C.F.R. pts. 365-66), *order on reh'g*, Order No. 667-A, [2006 Proposed Regs.] F.E.R.C. STATS. & REGS. ¶ 31,213 (2006), 71 Fed. Reg. 28,446 (2006) (to be codified at 18 C.F.R. pts. 365-66) [hereinafter Order No. 667-A], *order on reh'g*, Order No. 667-B, [2006 Proposed Regs.] F.E.R.C. STATS. & REGS. ¶ 31,224 (2006), 71 Fed. Reg. 42,750 (2006) (to be codified at 18 C.F.R. pt. 366) [hereinafter Order No. 667-B].

262. Order No. 667-A, *supra* note 261, at P 14.

263. *Id.* at PP 14, 36.

264. Order No. 667-A, *supra* note 261, at P 60.

265. *Id.* at P 63.

266. Order No. 667-B, *supra* note 261, at P 15.

revenues and therefore will not affect the availability of waiver of federal accounting and related requirements),²⁶⁷ and the definition of “gas utility company” (clarifying that a natural gas pipeline’s sales of natural gas to end-use customers located adjacent to the pipeline’s right of way would not, on that basis alone, result in the pipeline’s parent company being considered a holding company).²⁶⁸ The FERC also clarified that a subsidiary holding company may be eligible for an exemption or waiver even if an upstream holding company is not, and confirmed that centralized service companies within an exempt holding company system are themselves exempt from the record-retention and accounting requirements of the PUHCA 2005 regulations.²⁶⁹

In October, the FERC adopted, in Order No. 684, new accounting rules for holding companies and centralized service companies to allow for greater accounting transparency and to protect consumers against improper service company costs.²⁷⁰ Specifically, Order No. 684 adopted a new Uniform System of Accounts for centralized service companies and modified related financial reporting requirements contained in the FERC Form No. 60, Annual Report of Centralized Service Companies. Order No. 684 also established and codified record-retention requirements for both holding companies and service companies. The implementation date for compliance with the new rules is January 1, 2008. Finally, Order No. 684 required the FERC Form No. 60 to be filed electronically.²⁷¹

In December, the FERC held a technical conference to discuss issues raised in the rulemaking proceedings in which Order Nos. 667 and 669, *et al.* were adopted. Specifically, the technical conference addressed: whether there were additional actions that the FERC should take to supplement the protections against cross-subsidization implemented by those Orders (e.g., adopting more specific cross-subsidization safeguards, adopting generic “ring fencing” conditions for merger approvals, etc.); whether the FERC should modify its cash management rules in light of the FERC’s authority over public-utility holding companies under PUHCA 2005; and whether the FERC should adopt additional exemptions and waivers from the PUHCA 2005 regulations and grant additional blanket authorizations under section 203.²⁷²

267. *Id.* at PP 20-22; *see also FPL Group, Inc.*, 116 F.E.R.C. ¶ 61,135 (2006) (granting in-state holding company waiver where revenues of EWGs and QFs were not included in out-of-state public-utility revenue calculation).

268. Order No. 667-B, *supra* note 261, at P 33.

269. *Id.* at PP 34-35.

270. Order No. 684, *Financial Accounting, Reporting and Records Retention Requirements Under the Pub. Util. Holding Co. Act of 2005*, [2006 Proposed Regs.] F.E.R.C. STATS. & REGS. ¶ 31,229 (2006), 71 Fed. Reg. 65,200 (2006) (to be codified at 18 C.F.R. pts. 366-69, 375) [hereinafter Order No. 684].

271. The electronic filing requirement of Order No. 684 applies to reporting years commencing with 2008. *Id.* at P 238. In Order No. 685, FERC required the electronic filing of the FERC Form No. 60 for reporting years 2006 and 2007. Order No. 685, *Electronic Filing of FERC Form No. 60*, [2006 Proposed Regs.] F.E.R.C. STATS. & REGS. ¶ 31,230 (2006), 71 Fed. Reg. 65,049 (2006) (to be codified at 18 C.F.R. pts. 366, 385).

272. *See* FEDERAL ENERGY REGULATORY COMM’N, TECHNICAL CONFERENCE ON PUB. UTIL. HOLDING CO. ACT OF 2005 AND FED. POWER ACT SECTION 203 ISSUES: SECOND SUPPLEMENTAL NOTICE OF TECHNICAL CONFERENCE (2006), <http://www.ferc.gov/EventCalendar/Files/20061128104311-AD07-2-000.pdf>.

National Grid USA was a registered public utility holding company with nine affiliated utility operating companies under the Public Utility Holding Company Act of 1935 (PUHCA 1935),²⁷³ which was repealed effective February 8, 2006.²⁷⁴ The Securities and Exchange Commission (SEC) previously authorized National Grid USA to engage in various financing transactions²⁷⁵ under PUHCA 1935. In anticipation of repeal of PUHCA 1935, National Grid USA filed an application with the Commission requesting authorization, under section 204, for its public utility subsidiaries to issue short-term debt securities to third-party lenders as well as in connection with intra-family borrowings from its money pool and from upstream associate companies, provided that the aggregate principal amount outstanding did not exceed the certain stated amounts for each of the National Grid subsidiaries. National Grid USA also requested authorization for the National Grid Subsidiaries to receive open account advances from holding companies within the holding company system without limit as to the dollar amounts advanced, but the advances would be without interest. National Grid also noted that its holding companies occasionally make capital contributions to one or more of the National Grid subsidiaries to ensure their ability to meet financial requirements at all times, but that such capital contributions are not subject to Commission jurisdiction under section 204 because they involve no issuance of capital stock.²⁷⁶

A March 2, 2006, Director letter order²⁷⁷ authorized National Grid's subsidiaries to issue short-term debt securities, as well as receive capital contributions and open account advances from their parent company, provided that the aggregate principal amount outstanding did not exceed the amounts listed above for each subsidiary. National Grid filed a requested rehearing of the letter order arguing that the Commission erred by asserting jurisdiction over capital contributions that do not involve the issuance of securities and by placing monetary limits on the capital contributions and the open account advances made by holding companies to the public utility subsidiaries.

On rehearing,²⁷⁸ the Commission removed the aggregate dollar limitations that the March 2 letter order placed on the capital contributions and non-interest-bearing, open-account advances. With regard to the jurisdictional issue, the Commission held that to the extent that a capital contribution, or an open account advance by a parent holding company to a public utility subsidiary does not involve issuance of a security by the public utility, prior authorization of the contribution transaction is not required under section 204. However, to the extent that an infusion of capital or an open account advance by a parent holding

273. 15 U.S.C. §§ 79-79z-6 (2000).

274. See Energy Policy Act of 2005 § 1263.

275. See National Grid Transco, Holding Company Act Release No. 27,898, 83 SEC Docket 2653 (Sept. 30, 2004) (2004 WL 2240400); National Grid Transco PLC, Holding Company Act Release No. 27,950, 84 SEC Docket 3577 (Mar. 9, 2005) (2005 WL 562631).

276. Capital contributions, as well as non-interest bearing open account advances, were authorized under Rule 45(b) of the SEC's regulations under PUHCA 1935. 17 C.F.R. § 250.45(b)(4) (2005). Specifically, Rule 45(b)(4) stated that companies did not have to receive prior approval from the SEC to make capital contributions or open account advances, without interest, to a subsidiary. *Id.*

277. *National Grid USA*, 114 F.E.R.C. ¶ 62,210 (2006).

278. *National Grid USA*, 115 F.E.R.C. ¶ 61,241 at PP 15-19 (2006).

company does involve issuance of an equity security by a public utility subsidiary, then, the Commission stated, prior authorization under section 204(a) is required for such issuance.²⁷⁹

The Commission stated that the issuance of equity securities under this authorization in connection with a capital contribution, furthers the public interest in ensuring the sound financial condition of the public utility and will not impair, but rather promote, the ability to perform service as a public utility.²⁸⁰ The Commission also agreed that open account advances at no interest that involve issuance of an evidence of indebtedness can serve an important function in utility finance by providing an expeditious back-up to other forms of financing, such as money pools, and that the:

issuance of evidence of indebtedness by a public utility subsidiary to, and in connection with an open account advance by, the parent holding company is also consistent with the Commission's recently adopted regulation granting blanket authorization, under section 203(a)(2) of the FPA, for a holding company to acquire securities, in any amount, issued by a subsidiary.²⁸¹

However, while the Commission observed that non-interest bearing open account advances by a holding company to a public utility subsidiary are infrequent, "to ensure that when they do occur they are consistent with the requirements of [s]ection 204," the Commission directed that whenever there is an open account advance, an authorized officer of the public utility must certify, within thirty days of the date of the advance: (1) that, at the time of the advance, repayment of the funds advanced will not impair the ability of the public utility to perform as a public utility; and (2) the intended use or uses of the funds advanced.²⁸²

In Docket No. PH06-85, Barrick Gold Corporation and Barrick Goldstrike Mines Inc. (Barrick) notified the FERC of Barrick's eligibility for exemption from PUHCA 2005.²⁸³ In its exemption notification, Barrick stated that it controlled a single-state electric utility company system with a capacity of greater than 100 MW, used at least in substantial part for self-generation purposes.²⁸⁴ Over a period of several months, Barrick made several supplemental filings addressing a number of regulatory issues including single-state service, FERC-jurisdictional transmission facilities, utility affiliation, and captive customers. On October 11, 2006, the Commission Secretary advised Barrick by delegated order that its filing had been permitted to become effective by operation of law.²⁸⁵

In Docket No. PH06-48, Legg Mason, Inc. sought exemption from PUHCA 2005 as a passive financial investor. Legg Mason holds an interest of over nineteen percent in AES Corporation, which is itself the parent entity of several public-utility companies. AES is also the developer of a proposed Liquefied

279. *Id.* at P 16.

280. 115 F.E.R.C. ¶ 61,241 at P 16.

281. *Id.* at P 18.

282. 115 F.E.R.C. ¶ 61,241 at P 19.

283. Notice of Electric Filings, 71 Fed. Reg. 38,393 (July 6, 2006).

284. *Barrick Gold Corp.*, Docket No. PH06-85 (F.E.R.C. June 15, 2006).

285. *Notice of Effectiveness of Holding Company and Transaction Exemptions and Waivers re Questar Corporation, C&T Enterprises, Inc.*, Docket No. PH06-71 (F.E.R.C. October 11, 2006).

Natural Gas (LNG) facility in Maryland. Opponents of the LNG facility protested Legg Mason's notification of exemption, and the FERC Staff forwarded a series of technical inquiries to Legg Mason. Legg Mason answered the protest and the FERC Staff's inquiries, and on September 22, 2006, the FERC ruled Legg Mason to be eligible for exemption from PUHCA 2005 notwithstanding its indirect holdings of greater than ten percent of the voting securities of a public-utility company. The Commission based its decision in part on the finding that Legg Mason's holdings in AES were associated with Legg Mason's investment advisory activities, did not reflect a unitary voting strategy, and were not relevant to the FERC's jurisdictional interests under PUHCA 2005.²⁸⁶

The provisions of PUHCA 2005 permit the exemption of financial entities that conduct passive investment activities in public-utility companies. To date, a number of banks, investment organizations, broker-dealers, and investment advisors have publicly sought waiver of or exemption from PUHCA 2005. These include Deutsche Bank, Union Bank of California, Brookfield Asset Management, ArcLight Capital, Merrill Lynch & Co., Inc., Sowood Capital, and a number of special-purpose leasing entities.

VII. SECTION 203 AND MERGER DEVELOPMENTS

In April, the FERC largely reaffirmed Order No. 669,²⁸⁷ which amended the FERC's section 203 regulations concerning mergers, acquisitions, and dispositions of assets, but provided clarifications and granted additional blanket authorizations for certain transactions under section 203.

Specifically, in Order No. 669-A, among other things, the FERC: (a) confirmed that owners of EWGs, QFs, and FUCOs are "electric utility companies" subject to section 203(a)(2), but granted blanket authorization for persons that are holding companies solely by virtue of owning EWGs, QFs, or FUCOs to acquire additional EWGs, QFs, and FUCOs without additional FERC approval;²⁸⁸ (b) clarified that public utilities have blanket authorization to acquire securities of other public utilities in the context of intra-system cash management transactions, subject to protections against cross-subsidization and encumbrances of utility assets;²⁸⁹ (c) clarified that the previously granted blanket authorization for certain holding company acquisitions involving internal corporate reorganizations also applies to public utility transactions within the holding company, as long as the restructuring does not result in the reorganization of a traditional public utility that has captive customers or that

286. *Legg Mason, Inc.*, 116 F.E.R.C. ¶ 61,268 (2006).

287. Order No. 669, *Transactions Subject to FPA Section 203*, [2006 Proposed Regs.] F.E.R.C. STATS. AND REGS. ¶ 31,200, (2006) 71 Fed. Reg. 1348 (2006) (to be codified at 18 C.F.R. pts. 2, 33), *order on reh'g* [hereinafter Order No. 669]; Order No. 669-A, *Transactions Subject to FPA Section 203*, [2006 Proposed Regs.] F.E.R.C. STATS. AND REGS. ¶ 31,214 2006, 71 Fed. Reg. 28,422 (2006) (to be codified at 18 C.F.R. pts. 2, 33), *order on reh'g* [hereinafter Order No. 669-A]; Order No. 669-B, *Transactions Subject to FPA Section 203*, [2006 Proposed Regs.] F.E.R.C. STATS. AND REGS. 31,225 (2006), 71 Fed. Reg. 42,579 (2006) (to be codified at 18 C.F.R. pts. 2, 33) [hereinafter Order No. 669-B].

288. Order No. 669-A, *supra* note 287, at PP 49, 51, 52.

289. *Id.* at PP 89-91.

owns or provides transmission service over jurisdictional transmission facilities;²⁹⁰ (d) granted additional blanket authorizations to certain holding companies and their subsidiaries regulated by the Bank Holding Company Act to acquire securities in the normal course of business, as a fiduciary, for derivatives hedging purposes incidental to the business of banking, as collateral for a loan or for other limited purposes, but subject to certain restrictions and reporting requirements;²⁹¹ (e) granted blanket authorizations for certain acquisitions of utility securities for purposes of underwriting and hedging transactions, but subject to conditions and reporting requirements;²⁹² (f) clarified that “captive customers” include wholesale and retail energy customers served under cost-based regulation;²⁹³ (g) conditioned blanket authorizations granted to holding companies with public utilities that have “captive customers” or that own or provide transmission service over jurisdictional transmission facilities to acquire securities of intrastate-only, local distribution-only, and/or retail-only utilities on the holding companies reporting covered transactions to the FERC (including reporting any state actions or conditions related to the transactions) and explaining how the transactions do not result in cross-subsidization at the expense of captive customers;²⁹⁴ and (h) added a specific requirement that an applicant (other than in transactions covered by a blanket authorization) disclose existing pledges and/or encumbrances of utility assets and make detailed showings that the proposed transaction will not result in cross-subsidization or pledges or encumbrances of utility assets or, if assurances cannot be made, an explanation of how the transaction is consistent with the public interest.²⁹⁵

In July, on rehearing, the FERC largely reaffirmed the determinations it made in Order No. 669-A. Thus, in Order No. 669-B, among other things the FERC: (a) rejected requests to modify the definition of “electric utility company;”²⁹⁶ (b) clarified that activities that are part of cash management programs are eligible for the blanket authorization granted in Order No. 669-A, even if they are not part of a formal money pool;²⁹⁷ (c) clarified that, if a transaction involves the purchase of public-utility securities with a value below \$10 million, the transaction does not require authorization under section 203(a)(1)(C) even if ten percent or more of voting securities are involved (unless the transaction involves a public utility disposing of the whole of its facilities);²⁹⁸ (d) affirmed the blanket authorization granted under section 203(a)(2) for holding companies that own or control only EWGs, QFs, or FUCOs to acquire the securities of additional EWGs, FUCOs, or QFs;²⁹⁹ and (e) modified the

290. Order No. 669-A, *supra* note 287, at PP 73-74.

291. *Id.* at PP 124, 131.

292. Order No. 669-A, *supra* note 287, at PP 130-131.

293. *Id.* at P 147.

294. Order No. 669-A, *supra* note 287, at PP 62, 164.

295. *Id.* at PP 144, 164.

296. Order No. 669-B, *supra* note 287, at PP 16-17.

297. *Id.* at P 23.

298. Order No. 669-B, *supra* note 287, at P 28.

299. Order No. 669-B, *supra* note 287, at P 39. To the extent any such entities are “public utilities,” authorization may nonetheless be required under section 203(a)(1) for such entities’ dispositions of jurisdictional assets. *Id.* at PP 39, 42, 44.

general information requirements concerning cross-subsidization explanations.³⁰⁰

A. *Blanket Authorization*

In *Goldman Sachs*,³⁰¹ the FERC granted certain blanket authorizations under section 203(a)(2) for the acquisition of public-utility securities that were broader than the blanket authorizations granted under Order Nos. 669 and 669-A. In that case, Goldman Sachs, an investment banking, securities, and investment management firm with subsidiaries that engage in the generation and sale of electricity, had requested blanket authorization for its “non-utility subsidiaries”—essentially, broker-dealers and underwriters—to acquire securities, in the ordinary course of business, of any electric utility company, any transmitting utility, or any holding company in any holding company system that includes a transmitting utility or electric utility company, subject to substantially the same limitations, exclusions, and conditions that the FERC had approved for certain banks and subject to their not gaining control of the operation or management of the securities issuer.

In response, the FERC first clarified that subsidiaries of a holding company that are not themselves holding companies are not required to seek prior authorization under section 203(a)(2) for the purchase or acquisition of public-utility securities; nor are the upstream holding-company owners of such subsidiaries required to seek section 203(a)(2) authorization for their non-holding company subsidiaries’ acquisitions.³⁰² The FERC emphasized, however, that other approvals under section 203 may be required for such acquisitions; for example, if the acquisition resulted in a transfer of control over jurisdictional public-utility facilities with a value greater than \$10 million, then authorization under section 203(a)(1)(A) would be required.³⁰³

The FERC declined to grant Goldman Sachs’s request that the FERC conclude a company does not become a holding company by virtue of holding securities in a fiduciary capacity. According to the FERC, Goldman Sachs had failed to explain how its broker-dealer and asset-management functions fell within the specific statutory exemptions from the definition of “holding company” for broker-dealers and banks.³⁰⁴

Because Goldman Sachs was not granted these exemptions, the FERC addressed Goldman Sachs’s alternative request for blanket authorization under section 203(a)(4), which requires the FERC to approve a transaction if it finds that the proposed transaction will be consistent with the public interest and will not result in cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets for the benefit of an associate company, unless the FERC determines that the cross-subsidization, pledge, or encumbrance will be consistent with the public interest. Because these issues were then pending

300. Order No. 669-B, *supra* note 287, at P 49.

301. *The Goldman Sachs Group, Inc.*, 114 F.E.R.C. ¶ 61,118 (2006), *reh’g denied*, 115 F.E.R.C. ¶ 61,303 (2006) [hereinafter *Goldman Sachs*].

302. *Id.* at PP 13-14.

303. *Goldman Sachs*, *supra* note 301, at P 15.

304. *Id.* at P 18.

on rehearing of Order No. 669, and because Goldman Sachs's activities had been permitted by the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935 (PUCHA 1935, which had been repealed by EAct 2005), the FERC granted a temporary (one-year) authorization to Goldman Sachs's non-utility subsidiaries to continue to acquire and hold certain public-utility and transmitting-utility securities, subject to certain limitations, exclusions, and conditions.³⁰⁵ These included, for example:

- The periodic reporting of voting securities acquired pursuant to the blanket authorization;
- The limitation of ownership of voting securities of any individual company to ten percent, provided that no right to control the operation or management of the issuer is acquired;
- The exclusion from the ten percent limit of acquisitions of debt securities, dealer/trader activities, fiduciary holdings, acquisitions of securities in connection with underwriting activities, and securities acquired for hedging purposes (subject to a commitment not to vote securities in excess of the ten percent limit); and
- The exclusion from the ten percent limit and reporting obligations of the acquisition of the securities of electric utilities companies and electric holding companies not owning or operating any facilities located in and used for the generation, transmission, or distribution of electric energy in the United States.³⁰⁶

On rehearing of *Goldman Sachs*, the FERC denied a request to modify the quarterly reporting requirement included in the FERC's blanket authorization and dismissed a request for blanket authorization to acquire securities of industrial self-generators, as that authorization had been granted by Order No. 669-A.³⁰⁷

Separately, the FERC granted to an investment advisor company and the mutual funds to which it provides investment management services blanket authorization under section 203(a)(2) to acquire the securities of electric utilities, transmitting utilities, and public-utility holding companies, subject to various limitations and conditions. The authorization allowed the mutual funds to own, in the aggregate, up to twenty percent of a single public utility's securities. Each individual company was limited to ten percent ownership, and the FERC relied upon the enforcement oversight provided by the SEC over the mutual funds, as well as the conditions that would preclude the exercise of control over any public utility.³⁰⁸ The FERC also concluded that, because of their functional separation and independence, the securities held by the investment management company should not be attributed to an affiliated investment manager that also was

305. *Goldman Sachs*, *supra* note 301, at P 27. See also *Morgan Stanley*, 114 F.E.R.C. ¶ 61,119 at P 11, *reh'g denied*, *Morgan Stanley*, 115 F.E.R.C. ¶ 61,303 (2006) (finding Morgan Stanley to be a holding company and granting one-year blanket authorization under section 203(a)(2) subject to the Goldman Sachs conditions).

306. *Goldman Sachs*, *supra* note 301, at P 22.

307. 115 F.E.R.C. ¶ 61,303, at PP 9, 12, 13.

308. *Capital Research & Mgmt. Co.*, 116 F.E.R.C. ¶ 61,267 at PP 29-30 (2006).

granted blanket authorization (and vice versa).³⁰⁹ The FERC similarly granted blanket authorization to acquire public utility securities under section 203(a)(1), subject to certain limitations and conditions.³¹⁰ These authorizations were granted for three years.³¹¹

In connection with public-utility financing transactions, the FERC granted a one-year blanket authorization under section 203(a) to a public-utility holding company to engage in money pool transactions that involve acquisitions by its public-utility subsidiaries of each others' securities valued in excess of \$10 million, subject to the same limits on such transactions that the SEC had imposed under PUHCA 1935.³¹² The FERC also clarified that stock repurchases by the holding company from the open market (to manage its capital structure and to issue shares under stock plans) did not require section 203 authorization.³¹³

Finally, the FERC granted blanket authorization, under section 203(a), to the jurisdictional signatories to the Spare Transformer Sharing Agreement for the future transfers of transformers under that Agreement, including transfers of transformers by public utilities to their affiliates.³¹⁴ The authorization allows the public-utility signatories to sell, without obtaining additional section 203 authorization, jurisdictional transformers to each other in the event of the destruction of a substation by an act of terrorism, as required by the Agreement. Although the Agreement would allow additional transfers in other circumstances, the FERC declined to grant blanket authorization for those other permissible transfers, but encouraged the participating public utilities to expand the class of transfers that would be required by the Agreement and to seek blanket authorization for those additional transfers.³¹⁵ The FERC required the public utilities making any authorized transfers to report the transfers and file information required by the section 203 regulations.³¹⁶

In April 2006, Entegra Power Group, LLC (Entegra) received blanket authorization for transfers of certain ownership interests in project companies it owned.³¹⁷ Entegra is a special purpose investment vehicle through which a group of lender-owners, which include wholly-owned subsidiaries of Morgan Stanley and Merrill Lynch & Co. (MS&Co and MLPFS, respectively), holds ownership interests in certain generation project companies. Entegra has two classes of ownership interests: Class A Unit holders are active investors with full

309. 116 F.E.R.C. ¶ 61,267 at P 33.

310. *Id.* at P 37.

311. 116 F.E.R.C. ¶ 61,267 at P 46.

312. *Nat'l Grid plc & Nat'l Grid USA*, 114 F.E.R.C. ¶ 61,115 at P 10 (2006). *See also Exelon Corp.*, 114 F.E.R.C. ¶ 61,116 at P 9 (2006) (authorizing money pool transactions); *Entergy Servs., Inc.*, 114 F.E.R.C. ¶ 61,120 at P 10 (2006) (authorizing money pool transactions).

313. 114 F.E.R.C. ¶ 61,115 at P 11.

314. *Edison Elec. Inst. on Behalf of the Jurisdictional Signatories to the Spare Transformer Sharing Agreement*, 116 F.E.R.C. ¶ 61,280 (2006). The FERC also granted certain assurances with respect to the recovery in transmission rates of the costs the public utilities will incur in connection with participation in the Agreement. *Id.* at PP 39-41, 43, 47-48, 50, 52.

315. 116 F.E.R.C. ¶ 61,280 at P 17.

316. *Id.* at P 22.

317. *Entegra Power Group, LLC*, 115 F.E.R.C. ¶ 62,038 (2006).

voting rights, while Class B Unit holders are passive investors with few voting rights.

Entegra received blanket authorization for transfers of Class A Units that could result in current and future Entegra Members holding up to twenty percent of the Entegra Class A Units, if certain criteria are met. One of the criteria is that the acquiring entity and its affiliates cannot own or control five percent or more of the voting interests in a public utility that has interests in any generation facilities or engages in any jurisdictional activities in relevant control areas or markets. In their Docket No. EC06-147 filing, the applicants sought additional blanket authorization because neither MS&Co nor MLPFS qualified for the blanket authorization granted in the April order since each is affiliated with a power marketer that operates in control areas where generating facilities indirectly owned by Entegra are located, although none of the power marketers own or control generation.³¹⁸

The applicants requested blanket authorization for the following categories of transfers without additional filings under section 203(a)(1) of the FPA:

- for a two-year period, transfers of Entegra Class A Units to MS&Co that will result in MS&Co, individually or together with its affiliates, holding twenty percent or less of Entegra Class A Units; and
- a similar authorization for transfers of Entegra Class A Units to MLPFS; and
- transfers of Entegra Class A Units from MS&Co and MLPFS to direct or indirect wholly-owned subsidiaries of the ultimate corporate parent of each.

The applicants also requested blanket authorization under section 203(a)(2):

- for a two-year period, for MS&Co and MLPFS to both acquire up to twenty percent of Entegra Class A Units; and
- for transfers of Entegra Class A Units from MS&Co and MLPFS to direct or indirect wholly-owned subsidiaries of the ultimate corporate parent of each.

The applicants committed to complying with substantial reporting requirements in connection with such transfers.

In granting the requested blanket authorization, the Commission found³¹⁹ that since the power marketers affiliated with MS&Co and MLPFS will not control generation in relevant control areas or markets, the affiliation of MS&Co and MLPFS with those power marketers does not pose competitive concerns. Accordingly, the Commission found also that the restriction of less than five percent of a public utility that engages in jurisdictional activities contained in the April Entegra order need not apply to their affiliation with such power marketers. The Commission clarified, however, that the April Entegra order's restriction of less than five percent of the voting interests in other generation in the relevant control areas or markets continues in force.

MACH Gen LLC (MACH Gen) is an investment vehicle which holds all of the ownership interests in certain generation project companies, and which is

318. *Entegra Power Group, LLC*, 117 F.E.R.C. ¶ 61,085 at P 20 (2006).

319. *Id.*

owned directly and indirectly by a group of lender-owners, each of which holds only a minority interest in MACH Gen. A Commission Order issued in 2005³²⁰ authorized: (1) specific transfers of equity interests in MACH Gen, including those in which both Lehman and Merrill Lynch acquired interests in MACH Gen; and (2) future transfers of equity interests on a blanket basis over a two year period from current or new owners to other current or new owners if certain conditions are met.

However that order provided that future transactions in MACH Gen:

will be permitted . . . without further section 203 application only if the buyer and its affiliates do not collectively own or control five percent or more voting interest in any generation facilities or engage in any jurisdictional activities in the geographic markets in which the Project Companies are located . . .³²¹

In their application, Lehman and Merrill Lynch sought to acquire more equity interests in MACH Gen which they could not do under the blanket authorization granted by the Commission in the 2005 order because they each owned or controlled a five percent or more voting interest in certain other generation facilities in the geographic markets or control areas in which the project companies were located. In addition, because both Lehman and Merrill Lynch were affiliated with power marketers, neither would meet the condition of the blanket authorization in the 2005 order that precluded affiliation with entities that engage in jurisdictional activities.

The applicants proposed to allow each seller to transfer some or all of its equity interests in MACH Gen to Lehman and/or Merrill Lynch in separate transactions. Once the transactions were complete, Lehman would hold up to an approximately 9.99 percent equity interest in MACH Gen, and Merrill Lynch would hold up to an approximately nineteen percent equity interest in MACH Gen. The applicants indicated that Lehman and Merrill Lynch intended to resell some of the equity interests they sought authorization to acquire in the proceeding, and stated that their authorization of the proposed transactions would give Lehman and Merrill Lynch enough time to complete the downstream sales, and would also provide a cushion should some of the contemplated downstream sales not occur.

In approving the proposed transactions, the Commission was satisfied that the proposed:

Consolidation of additional ownership interests in MACH Gen . . . with Lehman's and Merrill Lynch's existing ownership in either MACH Gen or other generation (or generation capacity) in the relevant markets or control areas, does not raise competitive issues. Even if ownership gave control, the increase in concentration brought about by consolidation of the Lehman's affiliate's ownership of other generation in NEPOOL (and, if relevant, Merrill Lynch's affiliates' ownership of other generation in the APS/SRP control areas) with the additional ownership interests . . . would not be enough to raise concern about market power in the generation market.³²²

320. *MACH Gen, LLC*, 113 F.E.R.C. ¶ 61,138 (2005).

321. *Id.* at P 40.

322. *MACH Gen, LLC*, 117 F.E.R.C. ¶ 61,187 at P 28 (2006).

Further, the Commission noted, the “power marketers affiliated with Lehman and [Merrill Lynch] will not control generation in relevant control areas or markets.”³²³

In granting applicants’ request for modification of the blanket authorization for Future Subsidiary Transactions, the Commission observed that the:

requested modification slightly expands the existing “Future Subsidiary Transactions” authorization by permitting MACH Gen owners (both present and future) to transfer their equity interests in MACH Gen “up” to a direct or indirect parent[, and that] MACH Gen owners will still be able to transfer their interests “horizontally” among subsidiaries of their direct or indirect parent company as before.³²⁴

However, the Commission found that this “request does not raise issues about changes in control or effects on competition, rates or regulation,” or about cross-subsidization.³²⁵

In addition, the Commission found that the “ability to transfer interests up the corporate organization chart of the owner to a direct or indirect parent is essentially no different than what we previously authorized. Previously, the transferred interest would have moved up through the parent and then down to a different subsidiary,”³²⁶ whereas the applicants sought to allow the transferred interest to remain with the parent.

Aggregate market shares are identical in both situations, and the project companies remain subject to Commission regulation in both situations. Further, the project companies’ sales of power at market-based rates, without captive customers, will be the same, and the holding company’s independence from a traditional regulated utility also will not change.³²⁷

B. Cross-Subsidization

The Commission’s Order in *Northwestern Corporation*³²⁸ addresses the Commission’s developing policy on cross-subsidization. In that case, the applicants sought approval for an acquisition under which NorthWestern Corporation, a combined gas and electric utility operating in several states in the upper Midwest, and its subsidiaries, would become indirect, wholly-owned subsidiaries of Babcock & Brown Infrastructure Limited, an Australian-based utility infrastructure company that owns and manages infrastructure businesses worldwide.³²⁹

To address cross-subsidization concerns, the applicants stated that “any cross-subsidization between NorthWestern’s utility operations and any [Babcock company] is unlikely because none of the [them] [1] own generation in any of the markets served by NorthWestern[,] . . . [2] sell or purchase electric energy, or

323. *Id.* at P 29.

324. 117 F.E.R.C. ¶ 61,187 at PP 38-39.

325. *Id.*

326. 117 F.E.R.C. ¶ 61,187 at P 39.

327. *Id.*

328. *MACH Gen, LLC*, 117 F.E.R.C. ¶ 61,187 at P 38 (2006).

329. *Id.* at P 1.

any non-power goods or services, from NorthWestern[,] . . . [and] [3] own or operate an energy trading desk.”³³⁰

The applicants further asserted that “they are required to comply with the Montana Commission’s ring-fencing requirements contained in . . . [a] settlement [among the] Montana Commission, [the Montana Consumer Counsel], and NorthWestern,”³³¹ under which:

- NorthWestern will maintain the ownership and control of its public utility assets, facilities, and operations;
- Under the [Babcock] holding company structure, NorthWestern’s public utility assets will be owned and maintained separate and apart from [Babcock’s] ownership, risks, and operations of any other businesses it now owns or may acquire;
- NorthWestern will not issue new debt except as authorized by the Commission, the Montana Commission, and other state commissions; NorthWestern will not pledge its assets to secure the indebtedness of an affiliated company, except as may be authorized by the Commission and the Montana Commission;
- NorthWestern will not provide loans, guarantees, advances, equity investments or working capital to an affiliated company, except as allowed by the Commission and the Montana Commission;
- NorthWestern will not enter into any contract with a subsidiary or an affiliate where the costs of the contract are to be recovered in utility rates paid by ratepayers, except as may be authorized by the Commission and the Montana Commission; and
- NorthWestern will maintain such separate books and accounting records for its utility operations as is required by the Commission, and will allow the Commission reasonable access to such books and records in accordance with applicable law.³³²

The Commission found³³³ that since in Exhibit M of their application applicants agreed to these ring-fencing measures, they had complied with the requirements in Order No. 669 designed to prevent cross-subsidization.

C. Acquisition of Transmission Assets

In the ITC Holdings case,³³⁴ the Commission refined its policy concerning the acquisition of transmission assets. In that case, ITC Holdings sought to acquire all of the general and limited partnership interests in Michigan Transco Holdings Limited Partnership Corp., which wholly owns its operational subsidiary Michigan Electric Transmission Company, LLC (METC).³³⁵ The applicants also requested authorization for an intra-corporate reorganization of affiliates of METC and NTD Path 15 “that would occur before the closing of the ITC Holdings acquisition transaction.”³³⁶

330. 117 F.E.R.C. ¶ 61,100 at P 54.

331. *Id.* at P 55.

332. 117 F.E.R.C. ¶ 61,100 at P 55.

333. *Id.* at PP 59-60.

334. *ITC Holdings Corp.*, 116 F.E.R.C. ¶ 61,271 (2006).

335. *Id.* at 1.

336. 116 F.E.R.C. ¶ 61,271 at P 1.

The major policy development in the ITC Holdings case was that to ensure that the transaction had no adverse impact on rates, the Commission required applicants to incorporate a hold harmless provision along the lines of the one approved in Consolidated Edison.³³⁷ The Commission was concerned, in particular, that “the inputs to [applicants’ transmission] formula rates could change as a result of the transaction, which could adversely affect transmission rates.”³³⁸ The Commission stated that “if applicants seek to recover merger-related costs through their transmission rates, they must submit an informational filing to the Commission that details how they are satisfying the hold harmless requirement,” by showing (1) specifically what “merger-related costs they are seeking to recover, and (2) . . . that those costs are exceeded by the savings produced by the merger.”³³⁹

D. Lease Transactions

1. Wisconsin Electric

The filing of Wisconsin Electric Power Company (Wisconsin Electric) in Docket No. EC07-14³⁴⁰ is a good example of a type of section 203 filing that did not have to be made prior to EPAct 2005, which, among other things,³⁴¹ amended section 203 to require Commission authorization for the acquisition of generation assets, including acquisition by lease.³⁴² In that filing, Wisconsin Electric and a number of its affiliates sought section 203 authorization to transfer certain generating assets and interconnection facilities among their corporate affiliates pursuant to some long-term lease agreements.³⁴³ The leases in question were integral components of Wisconsin Electric’s Power the Future program (PTF Program), a \$7 billion investment involving 1090 MWs of additional gas-fired generation (replacing two antiquated existing coal units) and 1230 MWs of additional “supercritical pulverized” coal-fired generation, along with retrofitting of some air quality control equipment and upgrading transmission infrastructure.³⁴⁴ The leases were specifically authorized under Wisconsin’s Leased Generation Law,³⁴⁵ a financing incentive that permits a public utility to acquire generating resources through an affiliate as an alternative to the utility constructing the generation itself.

The first of the two gas units was transferred to Wisconsin Electric from PWGS Project Company, a Wisconsin Electric affiliate specifically formed to develop, construct, and own the units, on July 16, 2005, through a lease

337. *Consolidate Edison, Inc.*, 94 F.E.R.C. ¶ 61,079 (2001).

338. 116 F.E.R.C. ¶ 61,271 at P 47.

339. *Id.* at P 48.

340. *Wisconsin Energy Corp.*, 117 F.E.R.C. ¶ 62,246 (2006).

341. Energy Policy Act of 2005, Pub. L. No. 109-58, § 1289, 119 Stat. 594.

342. *Id.* at 982.

343. 117 F.E.R.C. ¶ 62,246, at 64,665.

344. *Id.* at 64,665-66.

345. WIS. STAT. § 196.52(9) (2006).

arrangement.³⁴⁶ The remaining gas unit and the two coal units, upon completion and testing, will be transferred by long-term leases from affiliated project companies to Wisconsin Electric and, in the case of the two coal units, some interests in the units will be transferred to unaffiliated entities that have purchased limited interests in the entities constructing the facilities.³⁴⁷

Under the FPA statutory regime that existed during the planning, approval, and commitment stages of the PTF Program, which began in 1999, Wisconsin Electric's acquisition of the generation facilities would not have required FERC approval. The planned leased generation facilities and the associated intra-corporate transfers were the subject of lengthy proceedings at, and were approved by, the Public Service Commission of Wisconsin (PSCW).³⁴⁸ The PSCW's approval of the coal units was appealed and ultimately affirmed by the Supreme Court of Wisconsin.³⁴⁹ The PSCW's review of the application for the gas units involved consideration of alternatives proposed by Calpine, Mirant, and PG&E National Energy Group. By delegation order, the Commission approved³⁵⁰ Wisconsin Electric's Docket No. EC07-14 filing, which was not protested by any party.

VIII. MARKET BEHAVIOR AND ENFORCEMENT

A. *Final Anti-Manipulation Regulations*

On January 19, 2006, the Commission issued Order No. 670, a Final Rule implementing the prohibition on market manipulation set forth in the EPA of 2005.³⁵¹ The Final Rule provides that a violation of the prohibition on market manipulation occurs when a market participant:

- (1) [u]ses a fraudulent device, scheme or artifice, or makes a material misrepresentation or material omission . . . or engages in any act . . . that operates . . . as a fraud or deceit upon an entity;
- (2) with the requisite scienter [*i.e.*, intent or recklessness];
- (3) in connection with [a jurisdictional] purchase or sale of natural gas or [electricity] or [the transmission thereof]³⁵²

These new regulations do apply to any entity, including traditionally non-jurisdictional entities such as municipal utilities that engage in such prohibited

346. Because the transfer of the first gas unit occurred before the enactment of EPA 2005, Wisconsin Electric concluded that no Commission approval was necessary to its transfer.

347. Madison Gas & Electric Company (MG&E) and Wisconsin Public Power, Inc. (WPPI) exercised options to acquire limited ownership interests in the coal units. These entities filed separately for Commission approval for the transfer of their interests.

348. See *Re W.E. Power LLC*, Wis. P.S.C. Docket Nos. 05-AE-109, 05-CE117, 137-CE-104, 6650-CG-211, 2002 WL 32067560 (2002) [hereinafter *PSCW PW Order*]; *Application for Approval of Affiliated Interest Agreements Between Wis. Elec. Power Co. and Elm Road Generating Station*, Wis. P.S.C. Docket No. 05-CE-130 2004 WL 1125847 (2004) [hereinafter *PSCW Elm Road Order*].

349. *Clean Wis., Inc. v. Pub. Serv. Comm'n of Wis.*, 700 N.W.2d 768 (Wis. 2005).

350. *Wisconsin Energy Corp.*, 117 F.E.R.C. ¶ 62,246 (2006).

351. Order No. 670, *Prohibition of Energy Mkt. Manipulation*, [2006 Proposed Regs.] F.E.R.C. STATS. AND REGS. ¶ 31,202 (2006), 71 Fed. Reg. 4244 (2006) (to be codified at 18 C.F.R. pt. 1c) [hereinafter Order No. 670].

352. *Id.* at P 49.

conduct in connection with a Commission-jurisdictional transaction.³⁵³ In addition, the Commission determined that the Final Rule does not create an affirmative duty to disclose information during the course of typical negotiations.³⁵⁴

B. Rescission of Certain Market Behavior Rules

On February 16, 2006, the Commission rescinded its Market Behavior Rules 2 and 6,³⁵⁵ and adopted a Final Rule to codify Market Behavior Rules 1, 3, 4, and 5 in the Commission's regulations.³⁵⁶ The Commission determined that Market Behavior Rules 2 and 6, originally issued in November 2003, were no longer necessary as such rules are now encompassed by the Commission's new market manipulation rules, and rules concerning standards of conduct, respectively.³⁵⁷

The Commission's codification of Market Behavior Rules 1, 3, 4, and 5—rules designed to require compliant operation and scheduling of generation facilities, provide accurate and factual information and communications, provide accurate and factual data if reported to price index publishers, and require standard recordkeeping—is merely procedural and does not alter the rights or obligations of parties.³⁵⁸ Moreover, this action does not impose any new regulatory burden on market participants.³⁵⁹

C. Procedures for Contested Audits

On February 16, 2006, the Commission finalized procedures for contested audits.³⁶⁰ The procedures allow the subject of an audit to challenge an operational (rather than reliability) audit finding or proposed remedy before the Commission issues an order on the disputed matter in the audit.³⁶¹ Pursuant to the Final Rule, once the audit process is complete, if a company disputes any part of the audit, it may elect either a "paper hearing" or a full evidentiary hearing, if appropriate, to address the challenged parts of the audit.³⁶²

353. Order No. 667, *supra* note 261, at P 17.

354. *Id.* at P 35.

355. Order No. 674, *Conditions for Pub. Util. Mkt.-Based Rate Authorization Holders*, [2006 Proposed Regs.] F.E.R.C. STATS. AND REGS. ¶ 31,208 (2006), 71 Fed. Reg. 9695 (2006) (to be codified at 18 C.F.R. pt. 35) [hereinafter Order No. 674].

356. *Investigation of Terms and Conditions of Pub. Util. Mkt.-Based Rate Authorizations*, 114 F.E.R.C. ¶ 61,165 (2006), *reh'g denied*, 115 F.E.R.C. ¶ 61,053 (2006) [hereinafter *Market Behavior Rules Rescission Order*].

357. *Id.* at PP 1-2.

358. See *Market Behavior Rules Rescission Order*, *supra* note 356 (codifying Market Behavior Rules 1, 3, 4, 5 at 18 C.F.R. §§ 35.36, 35.37).

359. *Id.* at P 3.

360. Order No. 675, *Procedures for Disposition of Contested Audit Matters*, [2006 Proposed Regs.] F.E.R.C. STATS. AND REGS. ¶ 31,209 (2006), 71 Fed. Reg. 9698 (2006) (to be codified at 18 C.F.R. pts. 41, 158, 286, 349), *order on reh'g* [hereinafter Order No. 675]; Order 675-A, [2006 Proposed Regs.] F.E.R.C. STATS. AND REGS. ¶ 31,217 (2006), 71 Fed. Reg. 29,779 (2006).

361. *Id.* at P 1, n.5.

362. Order No. 675, *supra* note 360, at P 2, n. 6.

D. Civil Penalties

On December 21, 2006, the Commission issued a Policy Statement to provide guidance concerning the process that the Commission will use to assess civil penalties for violations of statutes, orders, rules, or regulations.³⁶³ The Energy Policy Act of 2005 substantially expanded the Commission's civil penalty authority—to assess penalties of up to \$1 million per day of violations.³⁶⁴

Pursuant to the Policy Statement, the Commission will follow a process by which it will: (1) provide notice of the proposed penalty and the facts comprising the violation; (2) provide for the alleged violator to either choose to have a hearing before an Administrative Law Judge (and subject to the typical administrative process) or accept the penalty assessment (subject to *de novo* review by a U.S. District Court); and (3) permit the filing of legal or factual arguments to justify a reduction or modification of the penalty.³⁶⁵ The penalized party may appeal either a final Commission order or a District Court order to a Court of Appeals of competent jurisdiction.³⁶⁶

IX. PURPA DEVELOPMENTS

The Commission, through two rulemakings implemented the amendments to the Public Utility Regulatory Policies Act of 1978 (PURPA) that were enacted as part of EAct 2005.

A. Revised Regulations Governing Small Power Production and Cogeneration Facilities

The Commission issued Order No. 671³⁶⁷ dated February 2, 2006, to implement the modifications to section 210 of PURPA that were enacted as part of section 1253 of EAct 2005.³⁶⁸ Two of the key EAct 2005 provisions concerned ensuring that the thermal output from new cogeneration facilities is used in a “productive and beneficial” manner (*see* section VIII, A-1, *supra*), and that the output of the new facility is fundamentally used for industrial, commercial, or institutional purposes (*see* section VIII-A-2, *supra*).

1. Thermal Output

Order No. 671 first dealt with standards that must be satisfied in order to demonstrate that the thermal output of a new cogeneration facility is used in a productive and beneficial manner. The Commission incorporated the EAct 2005 standard regarding thermal output in its regulations, and also eliminated its

363. *Process for Assessing Civil Penalties*, 117 F.E.R.C. ¶ 61,317 (2006).

364. *Id.* at P 3.

365. 117 F.E.R.C. ¶ 61,317 at P 5.

366. *Id.*

367. Order No. 671, *Revised Regulations Governing Small Power Prod. and Cogeneration Facilities*, [2006 Proposed Regs.] F.E.R.C. STATS. AND REGS. ¶ 31,203 (2006), 71 Fed. Reg. 7852 (2006), *order on reh'g* [hereinafter Order No. 671]; Order 671-A, [2006 Proposed Regs] F.E.R.C. STATS. AND REGS. ¶ 31,219 (2006), 71 Fed. Reg. 30,585 (2006) [hereinafter 671-A].

368. Energy Policy Act of 2005, Pub. L. No. 109-58, § 1253, 119 Stat. 594.

prior irrebuttable presumption regarding usefulness of a cogeneration facility's thermal output. The Commission instead will ensure that the thermal output will not be a sham and will consider various factors as to whether the product produced by the thermal energy is needed and whether there is a market for the product. The Commission presumes that thermal output of a facility is productive and useful if it is replacing a previously used thermal source.

The Commission also made clear that with regard to certification of new cogeneration facilities, if certain uses of thermal output were previously considered "productive and useful" under the Commission's prior regulations and case precedent, they would be considered "productive and beneficial" for purposes of the new regulations. The Commission notes that interested parties desiring to oppose a facility's certification as a qualified facility (QF) can attempt to demonstrate that the thermal output is not, in fact, used in a "productive and beneficial" manner after they review the facility's Form 556 filing and have the form describe the use of the thermal output. Once a QF has been certified by the Commission, absent changes in its operations, the purchaser of the electrical output of a new cogeneration facility may not later argue that the thermal output of a facility is not "productive and beneficial." For smaller cogeneration facilities (those 5 MW or smaller), the Commission will apply a rebuttable presumption that such smaller cogeneration facilities satisfy the "productive and beneficial" requirement.³⁶⁹

2. "Fundamental Use" Requirement

Order No. 671 adopts a case-by-case approach for determining whether a facility's fundamental use is for industrial, commercial, or institutional purposes, taking into account the facility's electrical, thermal, chemical, and mechanical output, and not used fundamentally for sale of power to an electric utility. The Commission will take into account the technological, efficiency, economic, and variable thermal energy requirements, as well as state laws applicable to sales of electric energy from a QF to its host facility. Order No. 671 also established a "safe harbor" within which a facility would presume to satisfy the fundamental use test. Specifically, for new cogeneration facilities seeking QF status, applicants must demonstrate that at least fifty percent of the aggregated annual energy output of the facility is to be used for industrial, commercial, residential, or institutional purposes, and not sold to an electric utility, in order to qualify under the "safe harbor" provisions.³⁷⁰ If they do, they are deemed to be in compliance with this requirement. Such new facilities must comply with the safe harbor for the first twelve months of operation, and for any subsequent calendar year.

If electric cogeneration facilities do not qualify for the "safe harbor" provision, they must demonstrate in their applications the percentage of aggregated annual energy output that is used for industrial, commercial, residential or institutional purposes, along with discussion and support for why the Commission should conclude that this section of PURPA is met taking into account the statutory criteria.

369. Order No. 671, *supra* note 367, at P 26.

370. *Id.* at P 51.

3. Other Features

As required by EPAct 2005 in Order No. 671, the utility ownership limitation was eliminated from all QFs. However, the Commission retained the ownership disclosure requirement in the Commission's Form 556. In addition, new cogeneration facilities can continue to self-certify as QFs.

The Commission also made clear that there is a rebuttable presumption that an existing QF does not become a "new cogeneration facility"³⁷¹—and hence subject to the new eligibility requirements—if it files an application for recertification reflecting either a change in ownership or a change in operation. In addition, the Commission retained the existing operating and efficiency standards for new oil and gas cogeneration facilities.

Lastly, the Commission closed what it viewed as a loop hole in its previous PURPA implementation by making clear that where QFs make non-PURPA (*i.e.*, non-avoided cost) sales, such sales are subject to the Commission's jurisdiction under sections 205 and 206 of the FPA (including the requirement that the sales be subject to a section 205 cost-based rate or market rate application). However, the Commission exempted non-PURPA sales from sections 205 and 206 requirements if the sales of energy or capacity made by QFs 20 MW or smaller, made pursuant to a contract executed on or before March 17, 2006 or made pursuant to a state regulatory authorities implementation of section 210 of PURPA.

4. Rehearing Order

In its Rehearing Order issued May 22, 2006, (Order No. 671-A), in considering the objections of various parties to raise or reduce the 20 MW level, the Commission upheld the 20 MW threshold under which non-PURPA sales would not be subject to its rate regulation.³⁷² The Commission also noted that self-certifications for new cogeneration facilities would be noticed in the Federal Register, enabling parties an opportunity to submit objections to the Commission where they believe the new facilities do not satisfy these standards.³⁷³

The Commission also clarified that a QF is an "electric utility company" within the meaning of PUHCA 2005. However, even though QFs are electric utility companies, they are exempt from regulation under PUHCA 2005.³⁷⁴

B. Mandatory Purchase Obligation

The Commission on October 19, 2006, also issued Order No. 688 implementing changes to the mandatory purchase obligation that were mandated by EPAct 2005.³⁷⁵ The Commission adopted the specific statutory requirements set forth in EPAct 2005 with regard to certain market condition and related

371. 18 C.F.R. § 292.205(d) (2006).

372. Order No. 671-A, *supra* note 367, at P 18.

373. *Id.* at P 23.

374. Order No. 671-A, *supra* note 367, at P 28.

375. Order No. 688, *New PURPA Section 210(m) Regulations Applicable to Small Power Prod. and Cogeneration Facilities*, [2006 Proposed Regs.] F.E.R.C. STATS. AND REGS. ¶ 31,203 (2006), 71 Fed. Reg. 64,342 (2006) (to be codified at 18 C.F.R. pt. 292), *reh'g pending* [hereinafter Order No. 688].

standards that must be satisfied before the Commission will eliminate the mandatory PURPA purchase obligation. The Commission determined that the Midwest ISO, PJM Interconnection, ISO-New England, and the New York ISO have established and operate wholesale markets that meet the statutory criteria for member utilities to qualify for relief from the mandatory purchase obligation. Consequently, the Commission established a rebuttable presumption that QFs above 20 MWs have non-discriminatory access to these four markets and that electric utility members should be relieved of their mandatory purchase obligation.³⁷⁶ The electric utility purchaser must be a member of the RTO in order to be eligible for the rebuttable presumption. The Commission also extended this presumption to ERCOT. The mandatory purchase obligation is not automatically terminated for electric utility members of these RTOs. Instead, such utilities must file applications for relief, and QFs in these markets may present evidence to rebut the presumption of access to markets because of operational characteristics or transmission constraints.³⁷⁷ The Commission must make a final determination regarding waiver of the mandatory purchase obligations within ninety days of filing the application for relief.³⁷⁸ If waiver has been granted and any material circumstances for which waiver was granted has changed, a state energy, a QF, or any other affected person may file for reinstatement of the purchase obligations. The applicant, in its request for reinstatement, bears the burden of providing evidence that those specific conditions under which waiver was granted have now changed and are no longer met.³⁷⁹

The Commission also established a rebuttable presumption that, for QFs of 20 MW or smaller, the purchase obligation was still necessary and will remain in effect in all markets.³⁸⁰ In order to rebut such a presumption, the electric utility must demonstrate that each small QF in question has non-discriminatory access to the market.

The Commission said it was premature to include the California ISO and the Southwest Power Pool in the category of RTOs and in the above mentioned rebuttable presumption; this is to have ongoing market efforts and only have "day one" markets.³⁸¹ Order No. 688 is subject to rehearing.

C. Net Metering and Discretionary Authority Under PURPA

With the enactment of EAct 2005, Congress provided a specific process under which state regulatory authorities and non-regulated utilities would be required to consider whether to offer net metering.³⁸² Thus, the Commission has

376. *Id.* at PP 83, 102.

377. Order No. 688, *supra* note 375, at P 83.

378. *Id.* at P 25.

379. Order No. 688, *supra* note 375, at P 192.

380. *Id.* at P 72.

381. Order No. 688, *supra* note 375, at PP 157, 163.

382. Section 1251 of EAct 2005 defines net metering service as "service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period." Energy Policy Act of 2005, Pub. L. No. 109-58, § 1251, 119 Stat. 594.

reconsidered its prior position with regards to its discretionary enforcement of authority under PURPA in matters relating to net metering and clarifies that PURPA does not require net metering.³⁸³ Under its discretionary authority in PURPA section 210(h)(2)(A), the Commission had previously compelled Midland Power Cooperative (Midland), a nonregulated utility, to provide net metering to an electric consumer with a wind facility. After the enactment of EPAct 2005, the Commission reversed a prior Order and made clear its intention not to intrude in matters addressed by Congress, concluding that the Commission did “not believe it appropriate that [it] go to court to require Midland to provide net metering when Congress enacted a specific provision of law that directs Midland to consider whether or not to provide net metering on its own.”³⁸⁴

The wind facility owner failed an appeal, requesting that the court compel the utility to offer net metering. The United States Court of Appeals for the District of Columbia Circuit dismissed the appeal, concluding that the Commission was not required under PURPA to bring action against Midland and clarified that the appellant’s only remedy under PURPA was to file an enforcement action in district court.³⁸⁵

X. RESOLUTION OF 2000-01 WESTERN ELECTRICITY MARKET ISSUES

A. *Proceedings Before the Federal Energy Regulatory Commission*

1. California Refund Proceeding

The California refund proceeding remains active, with no immediate end in sight. On January 26, 2006, the Commission issued an Order on Cost Filings (Cost Filing Order),³⁸⁶ addressing submissions by sellers seeking to reduce their refund liability via a demonstration that the Commission’s refund methodology would result in a total revenue shortfall for their transactions into the markets operated by the California Independent System Operator Corporation (Cal ISO) and California Power Exchange Corporation (Cal PX).³⁸⁷ The Commission later ruled on compliance filings submitted in response to the Cost Filing Order.³⁸⁸ The Commission also addressed many procedural and technical issues in various orders throughout the year.

383. See *Gregory Swecker*, 114 F.E.R.C. ¶ 61,205 (2006), *reconsideration denied*, 115 F.E.R.C. ¶ 61,084 (2006); *Western Farmers Elec. Cooperative*, 115 F.E.R.C. ¶ 61,323 at P 28 (2006) (Commission granted a generation and transmission cooperative’s request for a waiver of its sale obligation under PURPA, and its members’ purchase obligation under PURPA, and rejected a claim that offering net metering should be a condition to granting such waivers).

384. *Id.* at P 28. Note—the obligation to consider the new federal standards established by EPAct 2005 are applicable to electric utilities whose retail sales exceed 500 million kWh during a calendar year. 16 U.S.C. § 2612(a) (2000).

385. *Swecker v. FERC*, No. 06-1170, 2006 U.S. App. LEXIS 24872 (D.C. Cir. Oct. 3, 2006), *reh’g denied*, No. 06-1170 (D.C. Cir. Nov. 28, 2006).

386. *San Diego Gas & Elec. Co.*, 114 F.E.R.C. ¶ 61,070 (2006).

387. These submissions were made in response to Commission orders issued in 2005 that clarified the standards and procedures for cost filings. *San Diego Gas & Elec. Co.*, 112 F.E.R.C. ¶ 61,176, *clarified*, 112 F.E.R.C. ¶ 61,249 (2005).

388. *San Diego Gas & Elec. Co.*, 117 F.E.R.C. ¶ 61,151 (2006).

2. Settlements

The Commission approved certain new settlements resolving seller-specific issues in the California refund proceeding and related proceedings before the Commission.³⁸⁹ The Commission approved a settlement between Enron and Nevada Power Company, Sierra Pacific Power Company, and Sierra Pacific Resources on January 25, 2006.³⁹⁰ On May 22, 2006, the Commission approved a settlement with conditions that resolved issues concerning IDACORP and several of the California public utilities and governmental entities, as well as the Commission's Office of Market Oversight and Investigations.³⁹¹ As discussed below, further settlement discussions are ongoing under the auspices of the United States Court of Appeals for the Ninth Circuit.³⁹²

3. Show Cause Orders

As of December 31, 2006, virtually all entities named as respondents in the Commission's June 2003 show cause orders concerning alleged manipulation of the Cal ISO and Cal PX markets³⁹³ either have been dismissed by the Commission or have reached settlements with the Commission's Trial Staff (Trial Staff) that have been approved by the Commission. Although many of the Commission's orders granting motions to dismiss and approving settlements remain subject to pending requests for rehearing, Enron remains the only party currently subject to the evidentiary hearing procedures established in the Show Cause Orders. The procedural schedule in the Enron proceeding had been suspended to facilitate settlement discussions among the parties, and the Commission approved several new settlements in 2006 between Enron and other parties.³⁹⁴ However, Enron did not reach settlements with all parties, and the procedural schedule was reinstated in late 2006.³⁹⁵

389. In addition, the Commission issued orders on rehearing that affirmed its prior orders approving settlements with Reliant and Enron. *San Diego Gas & Elec. Co.*, 115 F.E.R.C. ¶ 61,271 (2006) [hereinafter Reliant]; *San Diego Gas & Elec. Co.*, 115 F.E.R.C. ¶ 61,032 (2006) [hereinafter Enron].

390. *San Diego Gas & Elec. Co.*, 114 F.E.R.C. ¶ 61,067 (2006).

391. *San Diego Gas & Elec. Co.*, 115 F.E.R.C. ¶ 61,230 (2006), *reh'g denied*, 117 F.E.R.C. ¶ 61,020 (2006).

392. See *infra* § IX.B.

393. *American Elec. Power Serv. Corp.*, 103 F.E.R.C. ¶ 61,345 (2003), *reh'g denied*, 106 F.E.R.C. ¶ 61,020 (2004); *Enron Power Mkt., Inc.*, 103 F.E.R.C. ¶ 61,346 (2003), *reh'g denied*, 106 F.E.R.C. ¶ 61,020 (2004) [hereinafter Show Cause Orders].

394. See *Enron Power Mkt., Inc.*, 117 F.E.R.C. ¶ 61,109 (2006) (approving settlement between Enron, Trial Staff, and the Public Utility District No. 1 of Grays Harbor, Washington); *Enron Power Mkt., Inc.*, 116 F.E.R.C. ¶ 61,299 (2006) (approving settlement between Enron, Trial Staff, and the City of Tacoma, Washington); *Enron Power Mkt., Inc.*, 116 F.E.R.C. ¶ 61,298 (2006) (approving settlement between Enron, Trial Staff, and the Attorney General of Montana); *Enron Power Mkt., Inc.*, 115 F.E.R.C. ¶ 61,377 (2006) (approving settlement between Enron and the Metropolitan Water District of Southern California); *Enron Power Mkt., Inc.*, 115 F.E.R.C. ¶ 61,376 (approving Enron settlements with, respectively, Trial Staff, Valley Electric Association, and the City of Santa Clara, California), *reh'g denied*, 117 F.E.R.C. ¶ 61,257 (2006).

395. See Order of Chief Judge Confirming Modification of Procedural Time Lines, *Enron Power Mkt., Inc.*, No. EL03-180-000 (Dec. 1, 2006); Order of Chief Judge Reestablishing Procedural Time Lines, *Enron Power Mkt., Inc.*, No. EL03-180-000 (Nov. 21, 2006).

B. Proceedings Before the United States Court of Appeals for the Ninth Circuit

1. Resolution of Challenges to California Refund Orders

On August 2, 2006, the Ninth Circuit issued an opinion in *Public Utilities Commission v. FERC*,³⁹⁶ addressing multiple petitions for review of Commission orders issued in the California refund proceeding. The petitions challenged the scope of the refund orders, as well as the Commission's determinations as to which transactions would be subject to refund. Although the court upheld the Commission's orders with respect to most of the matters subject to challenge,³⁹⁷ the court concluded that the Commission had acted arbitrarily and capriciously in declining to consider ordering a market-wide refund remedy for sales into the Cal ISO and Cal PX markets that took place prior to October 2, 2000, the date designated by the Commission as the refund effective date in response to the complaint under FPA section 206³⁹⁸ that commenced the California refund proceeding.³⁹⁹

In reaching this determination, the court acknowledged that the Commission lacked authority under section 206 to order refunds for unjust and unreasonable rates charged prior to the designated refund effective date.⁴⁰⁰ However, the court looked to section 309 of the FPA, pursuant to which the Commission has authority "to perform any and all acts, and to prescribe, issue, make, amend, and rescind such orders, rules, and regulations as it may find necessary or appropriate to carry out the provisions of [the FPA]."⁴⁰¹ The court stated that under this provision, the Commission has authority "to require that entities violating the Federal Power Act pay restitution for profits gained as a result of a statutory or tariff violation," and that this authority permits the Commission to order relief for tariff violations occurring prior to the refund effective date.⁴⁰² Although the Commission did seek to address alleged tariff violations in a variety of proceedings in which it posited disgorgement of profits as the ultimate remedy for violations by individual sellers (including the proceedings instituted by the Show Cause Orders referenced in the preceding section), the court determined that this was an insufficient response to requests for a "market-wide refund remedy for tariff violations pursuant to § 309"⁴⁰³

396. *Public Utils. Comm'n v. FERC*, 456 F.3d 1025 (9th Cir. 2006). The court subsequently issued an amended opinion, *Pub. Utils. Comm'n v. FERC*, 462 F.3d 1027 (9th Cir. 2006), and subsequent citations herein shall be to the amended opinion.

397. Most significantly, the court held that the Commission correctly excluded from the refund proceedings transactions involving purchases by the California Energy Resources Scheduling Division of the California Department of Water Resources (CDWR) in bilateral spot markets outside of the ISO and PX. *Public Utils. Comm'n v. FERC*, 462 F.3d at 1064.

398. 16 U.S.C. § 824e (2000).

399. *San Diego Gas & Elec. Co.*, 93 F.E.R.C. ¶ 61,121 at 61,370 (2000), *order on reh'g*, 97 F.E.R.C. ¶ 61,275, at 62,197-99 (2001). The court upheld the Commission's selection of October 2, 2000 as the refund effective date. *Public Utils. Comm'n v. FERC*, 462 F.3d at 1046-47.

400. *Public Utils. Comm'n v. FERC*, 462 F.3d at 1048.

401. 16 U.S.C. § 825h (2000).

402. *Public Utils. Comm'n v. FERC*, 462 F.3d at 1048.

403. *Id.* at 1051. A market-wide refund remedy would employ a methodology similar to that employed by the Commission in determining refunds for sales made after the October 2, 2000, refund effective date. The

Accordingly, the court remanded to the Commission to give further consideration to requests for a market-wide refund remedy, although the court stated that it did not “prejudge how [the Commission] should address the merits or fashion a remedy if appropriate.”⁴⁰⁴

The court further ruled that the Commission had erred in excluding certain types of transactions from the California refund proceeding. Specifically, the court concluded that the Commission acted arbitrarily and capriciously in excluding from the scope of transactions subject to refund sales made in the Cal ISO and Cal PX spot markets with durations of greater than 24 hours. The court determined that the Commission’s justification for excluding these sales—that the underlying complaint did not encompass transactions with durations of greater than twenty-four hours—was not supported by the record.⁴⁰⁵ The court also concluded that the Commission acted arbitrarily and capriciously in excluding energy exchange transactions from the California refund proceeding, rejecting as inadequate the Commission’s assertion that it could not determine whether particular exchange transactions were unjust and unreasonable because it could not determine how to assign a monetary value to such transactions.⁴⁰⁶

The court’s rulings could result in a substantial expansion of the California refund proceeding before the Commission. In an effort to encourage further settlements of issues arising out of that proceeding, the court simultaneously issued an order extending the time for filing petitions for panel rehearing and rehearing *en banc* of its order, and directed a senior circuit judge to explore the prospects of mediation between the parties.⁴⁰⁷ The Commission expressed its strong support for the mediation efforts, and selected former Commission administrative law judge William Cowan to act as special master for the Commission in the mediation process.⁴⁰⁸

2. Bilateral Forward Contract Cases

On December 19, 2006, the Ninth Circuit issued a pair of rulings addressing the Commission’s application of the *Mobile-Sierra*⁴⁰⁹ doctrine in denying complaints seeking modifications to long-term bilateral market-based electricity sales contracts entered into during the Western electricity crisis.⁴¹⁰ The Commission had denied the underlying complaints on the grounds that the

court noted that the California public utilities and governmental entities who support imposition of such a remedy assert that it would result in an additional \$2.3 billion in refunds over and above those already ordered by the Commission. *Public Utils. Comm’n v. FERC*, 462 F.3d at 1043.

404. *Public Utils. Comm’n v. FERC*, 462 F.3d at 1051.

405. *Id.* at 1057.

406. *Public Utils. Comm’n v. FERC*, 462 F.3d at 1060-61.

407. *Pub. Utils. Comm’n of Cal. v. FERC*, 465 F.3d 1025 (9th Cir. 2006).

408. Press Release, Fed. Energy Regulatory Comm’n, Chairman Urges Settlement of 2000-01 Energy Crisis Disputes as Federal Judge Opens Mediation Talks in San Francisco (Sept. 6, 2006).

409. *United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332 (1956); *Fed. Power Comm’n v. Sierra Pacific Power Co.*, 350 U.S. 348, 355 (1956).

410. *Pub. Utils. Dist. No. 1 of Snohomish County Wash. v. FERC*, 471 F.3d 1053 (9th Cir. 2006); *Pub. Utils. Comm’n v. FERC*, 474 F.3d 587 (9th Cir. 2006) (*Snohomish County* concerned challenges by purchasers under various bilateral forward contracts; *Public Utils. Comm’n v. FERC*, involved challenges by California state agencies to bilateral forward contracts entered into by CDWR).

contracts at issue were governed by the heightened *Mobile-Sierra* “public interest” standard, under which a party seeking to reform a contract must demonstrate that the rates “adversely affect the public interest,”⁴¹¹ and that the complainants had not succeeded in meeting that heightened burden.⁴¹² In its December 19 rulings, however, the court required the Commission to reconsider its orders based on the court’s interpretation of the *Mobile-Sierra* doctrine.

As an initial matter, the court stated that the only standard that applies to the lawfulness of wholesale electricity rates is the “just and reasonable” standard set forth in sections 205 and 206 of the FPA; the *Mobile-Sierra* doctrine simply stands for the proposition that the considerations as to what is “unjust” or “unreasonable” differ in the context of an established bilateral contract.⁴¹³ According to the court, in certain cases the Commission is entitled to presume that an established bilateral contract remains “just and reasonable” for the term of the contract.⁴¹⁴ Based on its review of precedent and “the context of *Mobile-Sierra*,” the court identified what it considers to be “three prerequisites” for that presumption to apply, all of which must be present:⁴¹⁵ “(1) “the contested contract by its own terms must not preclude the limited *Mobile-Sierra* mode of review;”⁴¹⁶ (2) “the regulatory scheme in which the contract [is] formed must provide [the Commission] with an opportunity for initial review of the contracted rate;”⁴¹⁷ and (3) “the scope of that review must permit consideration of the factors relevant to the propriety of the contract’s formation”⁴¹⁸—including whether the contract initially was formed free from the influence of improper factors such as market manipulation, market power, or market dysfunctions.⁴¹⁹

The court went on to consider whether these prerequisites were present so as to warrant a presumption that the underlying contract rates were just and reasonable. The court upheld the Commission’s determinations that in each instance the parties had waived their rights to seek modifications to the contract unilaterally.⁴²⁰ However, the court concluded that the other two prerequisites were not present. First, the court held that while market-based rate authority can qualify as sufficient prior review to justify limited review under *Mobile-Sierra*, it can only do so when accompanied by effective oversight permitting timely reconsideration of market-based authorization if market conditions change.⁴²¹ In the court’s view, such oversight was not present: the Commission’s quarterly

411. *Sierra Pac. Power Co.*, 350 U.S. at 355.

412. *Nevada. Power Co. v. Enron Power Mkt., Inc.*, 103 F.E.R.C. ¶ 61,353 at PP 110-11, *order on reh’g*, 105 F.E.R.C. ¶ 61,185 (2003); *Pub. Utils. Comm’n v. Sellers of Long Term Contracts to the Cal. Dep’t of Water Res.*, 103 F.E.R.C. ¶ 61,354 at PP 62-63, *order on reh’g*, 105 F.E.R.C. ¶ 61,182 (2003).

413. *Pub. Util. Dist. No. 1 of Snohomish County Wash. v. FERC*, 471 F.3d 1053, 1060-1061, 1075 (9th Cir. 2006). The court’s detailed analysis of the applicable legal standards appears in *Snohomish*, and is merely summarized in *Public Utils. Comm’n v. FERC*, 474 F.3d 587 (9th Cir. 2006).

414. *Id.* at 1061.

415. *Snohomish County Wash.*, 471 F.3d at 1061.

416. *Id.* at 1075.

417. *Snohomish County Wash.*, 471 F.3d at 1076.

418. *Id.* at 1077.

419. *Pub. Util. Dist. No. 1 of Snohomish County Wash. v. FERC*, 471 F.3d 1053, 1085-86 (9th Cir. 2006).

420. *Snohomish County Wash.*, 471 F.3d at 1079; *Pub. Utils. Comm’n*, 474 F.3d at 594.

421. *Snohomish County Wash.*, 471 F.3d at 1053; *Pub. Utils. Comm’n*, 474 F.3d at 594.

transaction reporting requirement and the opportunity to seek revocation of a sellers' market-based sales authority on a prospective basis do not suffice because there is no timely consideration of sudden market changes and no protection for purchasers victimized by abusive sellers or dysfunctional market conditions.⁴²² Second, the court held that the Commission had not meaningfully accounted for the market conditions existing during the Western electricity crisis, when the contracts were formed, and that it should have considered evidence regarding whether and how spot market dysfunctions affected the forward markets in which the contracts at issue were entered into.⁴²³

The court further concluded that the Commission had used an erroneous standard in analyzing the public interest considerations with respect to the contracts at issue. The court distinguished between cases where a customer challenges rates as excessively high and a seller challenges rates as excessively low, and stated that the Commission mistakenly analyzed the complaints under the standards applicable to a low-rate challenge.⁴²⁴ The Commission considered three factors identified by the Supreme Court in *Sierra*—whether the rate impairs the ability of the utility to continue service, whether it would place an excessive burden on other consumers, or whether the rate would be unduly discriminatory⁴²⁵—and concluded that the complainants had not satisfied these factors.⁴²⁶ In the Ninth Circuit's view, however, the primary consideration in high-rate challenges, such as those presented by the complainants, is assuring that the consuming public pays fair rates.⁴²⁷ The court concluded that the Commission had failed to address that consideration, and therefore had failed to assess the public interest with respect to any of the contracts before it.⁴²⁸ Accordingly, the Ninth Circuit remanded the cases to the Commission to determine whether *Mobile-Sierra* is applicable to the challenged contracts and, if so, to correctly apply the *Mobile-Sierra* review paradigm outlined by the court. If the Commission determines upon remand that the challenged contracts should not be reviewed under *Mobile-Sierra*, it should then apply full "just and reasonable" review.⁴²⁹

3. Further Developments Concerning Previously Decided Cases

On July 31, 2006, the Ninth Circuit issued an order⁴³⁰ denying without comment petitions for panel rehearing and rehearing *en banc* of *California ex rel. Lockyer v. FERC*,⁴³¹ in which the court ruled that the Commission erred in concluding that it lacked authority to order refunds for violations of reporting

422. *Snohomish County Wash.*, 471 F.3d at 1084; *Pub. Utils. Comm'n*, 474 F.3d at 594-95.

423. *Snohomish County Wash.*, 471 F.3d at 1085-87; *Pub. Utils. Comm'n*, 474 F.3d at 596.

424. *Snohomish County Wash.*, 471 F.3d at 1086; *Pub. Utils. Comm'n*, 474 F.3d at 596.

425. *Sierra Pac. Power Co.*, 350 U.S. at 355.

426. *Nevada. Power Co. v. Enron Power Mkt., Inc.*, 103 F.E.R.C. ¶ 61,353 at PP 96-101 (2003); *Pub. Utils. Comm'n v. Sellers of Long Term Contracts to the Cal. Dep't of Water Res.*, 103 F.E.R.C. ¶ 61,354 at PP 40-41 (2003).

427. *Snohomish County Wash.*, 471 F.3d at 1088.

428. *Id.* at 1089; *Pub. Utils. Comm'n*, 474 F.3d at 596-97.

429. *Snohomish County Wash.*, 471 F.3d at 1089; *Pub. Utils. Comm'n*, 474 F.3d at 597.

430. *California ex rel. Lockyer v. FERC*, No. 02-73093 (9th Cir. July 31, 2006).

431. *California ex rel. Lockyer v. FERC*, 383 F.3d 1006 (9th Cir. 2004).

requirements under the Commission's market-based sales regime. On December 28, 2006, a group of sellers filed a petition for a writ of certiorari in the United States Supreme Court, seeking review of the Ninth Circuit's ruling. In addition, on November 13, 2006, a group of California public utilities and governmental entities filed a petition for panel rehearing and rehearing *en banc* of *Bonneville Power Administration v. FERC*,⁴³² in which the court determined that the Commission lacked authority under the FPA to require governmental entities and an electric power cooperative to pay refunds for sales into the Cal ISO and Cal PX spot markets during the period covered by the California refund proceeding. These matters remain pending.

XI. PROCEDURAL DEVELOPMENTS/NO ACTION LETTERS

The Commission issued several "no-action" letters (NAL) in response to requests under its regulations permitting Commission Staff to give informal advice.⁴³³ The Commission's NAL procedures "make available informal advice by staff" on "specific proposed transactions, practices or situations that may raise issues under the Commission's regulations relating to the Standards of Conduct for Transmission Providers, . . . Market Behavior Rules, and the Commission's Prohibition of Energy Market Manipulation Rules."⁴³⁴

On January 31, 2006, the Commission issued its first "no-action" letter⁴³⁵ in response to a request filed by Cinergy Services, Inc, the Cincinnati Gas & Electric Company (CG&E), PSI Energy, Inc. (PSI), and the Union Light Heat and Power Company (ULH&P) (collectively, Cinergy) regarding the consistency of certain actions with Cinergy's codes of conduct. Cinergy sought a response from Commission Staff confirming that they would not recommend enforcement action relating to the transfer of three generating units from CG&E to ULH&P.⁴³⁶ Specifically, Cinergy sought clarification that its transfer of generating facilities to ULH&P would not raise enforcement concerns regarding shared employees between CG&E and ULH&P that would result from the transfer of the generation units.⁴³⁷ Cinergy stressed that such "shared employees do not participate in directing, organizing or executing the business decisions of the wholesale merchant or generation functions . . ." and that they do not "engage in economic decisions regarding plant dispatch . . ."⁴³⁸

Cinergy also requested clarification regarding joint purchases of non-power goods and services by CG&E for itself and ULH&P. Cinergy stated that this arrangement was favorable to ULH&P because CG&E had entered into long-term supply and transportation contracts for coal, fuel oil, and lime at prices that

432. *Bonneville Power Admin. v. FERC* 422 F.3d 908 (9th Cir. 2005).

433. See 18 C.F.R. § 388.104 (2006); see also *Informal Staff Advice on Regulatory Requirements, Interpretive Order Regarding No-Action Letter Process*, 113 F.E.R.C. ¶ 61,174 (2005) [hereinafter November 2005 NAL Interpretive Order].

434. November 2005 NAL Interpretive Order, *supra* note 433, at P 1.

435. No Action Letter, Cinergy Serv. Inc, *et al.*, Docket No. NL06-1-000 (Jan. 31, 2005) [hereinafter Cinergy No-Action Letter].

436. No Action Letter Request on Behalf of Cinergy Serv., Inc., *et al.* at 2, filed Dec. 20, 2005 [hereinafter Cinergy No-Action Request].

437. *Id.* at 4-8.

438. Cinergy No-Action Letter, *supra* note 435, at 5.

ULH&P would not likely be able to negotiate because of its smaller purchasing requirements. Because CG&E would purchase non-power goods and services, CG&E would know the price of these goods and services consumed by ULH&P. Cinergy stated that “[a]rguably, under the Commission’s broad definition of market information, the price of coal, fuel oil and transportation services could be considered market information . . .” and the sharing of such information could be violative of the code of conduct.⁴³⁹ On January 31, 2005, Commission Staff issued a letter to Cinergy stating that, based on the facts presented in Cinergy’s request, they would not recommend enforcement action.⁴⁴⁰

On March 17, 2006, and as revised on April 24, 2006, American Transmission Company LLC (ATCLLC) submitted a no-action letter request relating to Standard of Conduct concerns arising from the participation of ATCLLC and its affiliates in the Wisconsin System Operator Regional Training Program (WSO Program).⁴⁴¹ According to ATCLLC, the goal of the WSO Program is to provide operators with comprehensive training in various regulatory and operating areas, such as: (1) NERC Reliability Standards; (2) alternating and direct current power concepts; (3) components and configuration of facilities used in the construction of transmission, distribution, and facilities; and (4) power flow concepts relating to interconnected systems.⁴⁴² ATCLLC explained that while the WSO Program is geared to providing training to NERC certified operators, program participation is open to all operators and merchant function personnel.⁴⁴³ Thus, ATCLLC sought a recommendation of no enforcement, out of an abundance of caution, to ensure that Commission staff would not view the information exchanged at the WSO Program as violative of the Standards of Conduct.⁴⁴⁴

ATCLLC stated that several precautions would be taken to ensure the WSO Program would not violate the Standards of Conduct. First, no real-time transmission operation or customer-specific information would be used in the training program.⁴⁴⁵ Additionally, the training staff would not make available access to any customer-specific information or non-public transmission information.⁴⁴⁶ Further, to the extent that WSO Program trainers planned to use any historical information that had not previously been publicly posted, such information would be posted on the OASIS prior to the start of the program.⁴⁴⁷ Tours of facilities would not include any sites or control centers having access to non-public transmission information or customer specific information.⁴⁴⁸ Finally, prior to the start of each training session, ATCLLC stated that it would require each participant to sign a statement indicating that the participant

439. *Id.* at 14.

440. Cinergy No-Action Request, *supra* note 436, at 8-14.

441. Request for No-Action Letter Request by American Transmission Co. LLC, filed Mar. 17, 2006, amended Apr. 24, 2006 [hereinafter ATCLLC No-Action Request].

442. *Id.* at 4.

443. ATCLLC No-Action Request, *supra* note 441, at 3.

444. *Id.* at 5.

445. ATCLLC No-Action Request, *supra* note 441, at 7.

446. *Id.*

447. ATCLLC No-Action Request, *supra* note 441, at 7.

448. *Id.*

understood that the Standards of Conduct and No-Conduit rules applied to all program activities. On April 28, 2006, Commission Staff issued a letter to ATCLLC stating that, based on the facts presented in ATCLLC's request, they would not recommend enforcement action.⁴⁴⁹

On March 23, 2006, and as modified on June 16, 2006, Apache Corporation (Apache) filed a request for a no-action letter confirming that the Commission Staff would not recommend enforcement action under section 1c.c of the Commission's Natural Gas Market Manipulation Rules with respect to certain transactions.⁴⁵⁰ Specifically, Apache requested clarification that the use of a Net Settlement Agreement (NSA) and a NAESB Purchase and Sale agreement, to meet Apache's internal credit policies, would not be deemed to be a fraud, deceit, or "pre-arranged offsetting trades of the same product among the same parties, which involve no economic risk and no net change in the beneficial ownership of [the] gas."⁴⁵¹ Apache explained that it needed to enter into NSAs with certain counter-parties because it both sold to, and bought gas from, certain counter parties because "the most cost effective way to mitigate such [credit] risk is for the at-risk party [here Apache] to buy product from the party that has exceeded its credit limit."⁴⁵² On June 20, 2006, Commission Staff issued a letter to Apache stating that, based on the facts presented in Apache's request, they would not recommend enforcement action.⁴⁵³

On July 10, 2006, Texas Eastern Transmission, LP, Algonquin Gas Transmission, LLC, East Tennessee Natural Gas, LLC, Egan Hub Storage, LLC, Gulfstream Natural Gas System, L.L.C., Maritimes & Northeast Pipeline, L.L.C., and Saltville Gas Storage, LLC (collectively, the Duke Pipelines or Duke) requested a no-action letter indicating that the FERC Staff would not recommend enforcement action under the Commission's Standards of Conduct "in connection with a proposed arrangement under which an employee of a Canadian non-Energy Affiliate would be shared with an Energy Affiliate in order to conduct capacity release transactions, with respect to transportation contracts the Energy Affiliate holds on two non-affiliated Transmission Providers."⁴⁵⁴ The Duke Pipelines stated that the shared employee would be necessary because it was in the process of winding down operations of its affiliate company that previously handled capacity release.⁴⁵⁵ The Duke Pipelines further asserted that the capacity release responsibilities would be intermittent and would have sufficient safeguards to prevent the inappropriate sharing of non-public transmission or customer specific information. On August 25, 2006, Commission Staff issued a letter to the Duke Pipelines stating that, based on the facts presented in the Duke Pipelines' request, they would not recommend enforcement action.

449. No Action Letter, American Transmission Co., LLC, Docket No. NL06-2-000 (Apr. 28, 2006).

450. Request for No-Action Letter Request on behalf of Apache Corp., filed Mar. 23, 2006. [hereinafter Apache No-Action Request].

451. *Id.* at 5.

452. Apache No-Action Request, *supra* note 450, at 3.

453. No Action Letter, Apache Corp., Docket No. NL06-3-000 (Jun. 20, 2006).

454. Request for No-Action Letter of Texas Eastern Transmission, LP, filed July 10, 2006.

455. *Id.* at 2-3.

Finally, Chandeaur Pipe Line Company and Sabine Pipe Line Company (collectively, the Chevron Companies) filed requests for no-action letters relating to certain title transfer tracking services provided by their affiliate Sabine Hub Services Company (SHS).⁴⁵⁶ Chevron Corporation (CVX) owns the Chevron Companies and SHS.⁴⁵⁷ When the Chevron Companies implemented the Standards of Conduct in 2004, they “elected to err on the side of caution and take a conservative approach to compliance” and therefore listed SHS as an Energy Affiliate.⁴⁵⁸ The Chevron Companies reevaluated SHS’s status as an Energy Affiliate and came to believe that it is not an such an entity. While SHS provides title transfer and tracking services, it does not engage “in any of the activities enumerated by the Commission as characterizing an Energy Affiliate of a Transmission Provider.”⁴⁵⁹ According to the Chevron Companies, at no time does SHS “aggregate transmission capacity” nor does SHS “administer a tariff.”⁴⁶⁰ The Commission Staff responded on November 17, 2006, that they would not recommend enforcement actions against the Chevron Companies if they cease to classify SHS as an Energy Affiliate.⁴⁶¹

In addition to issuing specific no-action letters, the Commission also issued an interpretive order modifying the no-action letter process.⁴⁶² The October 2006 NAL Interpretive Order addressed the scope and applicability of the no-action letter process. First, the Commission addressed whether the no-action letter process “will continue to include questions regarding codes of conduct and all of the Market Behavior Rules.”⁴⁶³ The Commission noted that the scope of the original November 2005 NAL Interpretive Order was affected by Commission orders codifying and rescinding certain Market Behavior Rules.⁴⁶⁴ The Commission stated that once Market Behavior Rule 6 was rescinded by the Rescission Order, electric sellers’ codes of conduct were no longer within the scope of the no-action letter process “because they were no longer subject to the Market Behavior Rules.”⁴⁶⁵ However, the Commission found that “[s]ince we believe that these codes of conduct should be subject to the NAL process, and

456. Request for No-Action Letter: Chandeaur Pipe Line Co., filed Aug. 14, 2006, as amended Oct. 9, 2006 [hereinafter Chandeaur No-Action Request]; Request for No-Action Letter: Sabine Pipe Line Co., filed Aug. 21, 2006, as amended Oct. 9, 2006 [Sabine No-Action Request].

457. Chandeaur No-Action Request, *supra* note 456, at 2; Sabine No-Action Request, *supra* note 456, at 2.

458. *Id.*

459. Chandeaur No-Action Request, *supra* note 456, at 3; Sabine No-Action Request, *supra* note 456, at 3.

460. *Id.*

461. No Action Letter, Chandeaur Pipe Line, Docket No. NL07-2-000 (Nov. 17, 2006); No Action Letter, Chandeaur Pipe Line, Docket No. NL07-1-000 (Nov. 17, 2006).

462. *Informal Staff Advice on Regulatory Requirements*, 117 F.E.R.C. ¶ 61,069 (2005) [hereinafter October 2006 NAL Interpretive Order].

463. *Id.* at P 4.

464. October 2006 NAL Interpretive Order, *supra* note 462, at P 4 (noting that “in Order No. 674, the Commission amended 18 C.F.R. Part 35 (2005) to codify Market Behavior Rules 1, 3, 4, and 5. Second, in Order No. 673, the Commission rescinded sections 284.288(a), (d) and (e), and 284.403(a), (d) and (e) of the Commission’s codes of conduct regulations for natural gas sellers. Finally, the Commission’s Order Revising Market-Based Rate Tariffs and Authorizations (Rescission Order), a companion order to Order No. 674, was responsible for the rescission of Market Behavior Rules 2 and 6.”).

465. *Id.* at P 5.

consistent with the intent of the NAL Interpretive Order, the Commission hereby finds that the codes of conduct for both electric and gas sellers are appropriate NAL subject matter, despite the fact that they no longer fall under the Market Behavior Rules.”⁴⁶⁶ The Commission further clarified that the codified Market Behavior Rules are appropriate subject matter for no-action requests.⁴⁶⁷

The Commission also addressed the issue of whether Staff “can provide guidance on transactions or activities that are not themselves subject to the NAL process, but are ancillary to matters that are subject to the NAL process.”⁴⁶⁸ While the Commission does not believe that ancillary matters should be addressed in the no-action letter process, it indicated that where such matters are “inextricably intertwined with the issues that fall under the NAL process, declining to provide guidance regarding the ancillary matters may defeat the purpose of providing guidance on the matters that fall under the NAL process.”⁴⁶⁹ The Commission clarified that when a no-action letter request includes “one or more questions about subject matters that are not covered by the [no-action letter] process, Staff has discretion to consider such questions to the extent they are inextricably intertwined with an appropriate NAL question.”⁴⁷⁰

The Commission also considered whether parties should be able to use the no-action letter process to ask questions relating to activities pre-dating a particular no-action letter request.⁴⁷¹ The Commission stated that it created the no-action letter process to “provide an opportunity for regulated companies to obtain guidance that would assist them in remaining in compliance with the Commission’s regulations. . . . [It] did not intend the process to serve as a vehicle for regulated companies to obtain Staff opinions on whether prior conduct was lawful or not.”⁴⁷² Thus, the Commission stated that the no-action letter process would continue to address “existing practices and anticipated or proposed future practices and transactions.”⁴⁷³

The Commission addressed the issue of whether a party can withdraw a no-action letter request once it has been submitted to Staff, but before Staff issues a response (for instance, a party might believe “Staff would be inclined to issue a negative response to the request” and therefore the party might want to withdraw the request).⁴⁷⁴ The Commission stated that, since the adoption of the no-action letter process, the practice has been to permit parties to withdraw requests prior to the issuance of a response.⁴⁷⁵ Noting that the goal of the no-action letter process is to encourage companies to seek Staff guidance, the Commission clarified “that Staff may continue this practice”⁴⁷⁶ However the Commission also stated that Staff retains discretion to disallow withdrawal if

466. October 2006 NAL Interpretive Order, *supra* note 462, at P 5.

467. *Id.* at P 6.

468. October 2006 NAL Interpretive Order, *supra* note 462, at P 7.

469. *Id.*

470. October 2006 NAL Interpretive Order, *supra* note 462, at P 7.

471. *Id.* at P 8.

472. October 2006 NAL Interpretive Order, *supra* note 462, at P 8.

473. *Id.*

474. October 2006 NAL Interpretive Order, *supra* note 462, at P 9.

475. *Id.*

476. October 2006 NAL Interpretive Order, *supra* note 462, at P 9.

Staff “believes that the issuance of the NAL response has the potential to provide guidance on recurring questions of importance to the industry.”⁴⁷⁷

Finally, the Commission clarified that it will continue the practice of not charging a fee for the submission of no-action letter requests. The Commission, however, left open the possibility that it may reconsider whether a fee is appropriate.⁴⁷⁸

A. *Contested Audits*

On February 17, 2006, the Commission issued Order No. 675, a Final Rule addressing procedures for the disposition of contested audits.⁴⁷⁹ Prior to Order No. 675, audited parties who disagreed with “non-financial audit matters” approved by the Commission were required to seek rehearing of the Commission order.⁴⁸⁰ Order No. 675 provides for parties subject to operational audits to challenge the auditor’s findings before the Commission issues an order on the merits of any disputed findings or any proposed remedies.⁴⁸¹ The audited entity has the option of choosing between a shortened review procedure or a trial-type hearing to challenge the disputed audit findings/remedies.⁴⁸²

Under the shortened procedures, the audited entity and other interested parties are permitted to submit memoranda of the facts and law supporting their positions to the Commission.⁴⁸³ Should an audited entity choose to challenge audit findings by requesting review under the shortened procedures, the Commission will decide the issue on the basis of the materials submitted. Thus, the shortened procedures only provide for “paper” proceedings. Should an audited entity request a trial-type hearing, the Commission will assign the matter, unless it finds no material facts are in dispute, to an Administrative Law Judge (ALJ) pursuant to its regulations.⁴⁸⁴ Upon referral to an ALJ, a trial-type hearing will ensue pursuant to Part 385 of the Commission’s regulations.

B. *Docketing and Filing Requirements*

The Commission has adopted a number of technical filing and docketing practices under PUHCA 2005. Holding companies not otherwise entirely exempt from PUHCA 2005 by virtue of holding interests only in EWGs, QFs, and/or FUCOs are required to file their holding company status notifications on Form FERC-65, with exemption notifications due on Form FERC-65A and waiver notifications due on Form FERC-65B.⁴⁸⁵ A holding company seeking waiver or exemption must file both a Form FERC-65 and a Form FERC-65A or

477. *Id.*

478. October 2006 NAL Interpretive Order, *supra* note 462, at P 10.

479. Order No. 675, *supra* note 360; Order No. 675-A, *supra* note 362.

480. Order No. 675, *supra* note 360, at P 1.

481. Order No. 675, *supra* note 360, at P 22-23; 18 C.F.R. §§ 349.1 (2006).

482. Order No. 675, *supra* note 360, at PP 2, 6, 8.

483. 18 C.F.R. §§ 349.2-349.3 (2006).

484. 18 C.F.R. § 349.7 (2006).

485. *See generally* 18 C.F.R. § 366.4. The Commission has noted that there are no published blank forms FERC-65, and filers are expected to develop their own forms which must conform to the content and subscription requirements of 18 C.F.R. Pt. 366. *See* Order No. 667-A, *supra* note 261.

FERC-65B.⁴⁸⁶ Entities claiming exemption by virtue of holding interests only in EWGs, QFs, and foreign utility companies need not make Form FERC-65 filings at all, and may rely solely on their subsidiary-specific PUHCA exemption filings.⁴⁸⁷ The Commission will permit EWGs and foreign utility companies to self-certify their status, with immediate effect for conforming filings made in good faith.⁴⁸⁸

Holding company filings on Form FERC-65, as well as certain carry-over financing filings arising out of selected PUHCA 1935 matters, will be assigned “HC” docket prefixes. PUHCA 2005 waiver and exemption filings will be assigned “PH” docket prefixes. EWGs and QFs will continue to receive “EG” and “QF” docket prefixes, respectively. Foreign utility companies will receive “FC” docket prefixes.⁴⁸⁹

XII.RESTORING ELECTRICAL POWER IN THE AFTERMATH OF HURRICANES KATRINA AND RITA - LEGAL AND REGULATORY IMPLICATIONS

Hurricanes Katrina and Rita presented many challenges to both Entergy New Orleans, Inc. (ENO), the principal utility providing electric and gas service in New Orleans, and its local regulator, the New Orleans City Council. In the immediate aftermath of Katrina, communications in New Orleans were widely disrupted and a huge portion of ENO’s utility infrastructure was destroyed. Electric service was lost to 100% of the City’s consumers, transmission and distribution lines were down throughout the City and over fifty substations and ENO’s principal power plant were flooded. ENO’s customer base and revenue stream were non-existent. Funding was desperately needed to fund repair and reconstruction of the utility systems, but no federal emergency funds were available to ENO under the Stafford Act. In addition, ENO was forced to seek Chapter 11 bankruptcy protection since suppliers and creditors were unwilling to do business with it.

In response, the City Council established an expedited approval process for ENO’s emergency requests, reduced ENO’s operating costs by authorizing the temporary sale of low-cost power that ENO was obligated to pay for under long-term power purchase agreements, authorized the termination of unnecessary hedging contracts, and participated in ENO’s bankruptcy proceeding. After these initial emergency measures were taken, the parties focused on longer term issues; ensuring that ENO received Community Development Block Grant (CDBG) funds, the need for ENO to obtain certain limited rate increases, and the long-term financial health of ENO. As part of the long-term, the City Council is also promoting an energy efficiency program, conservation, sustainability initiatives, and “green” building.

ENO and the City Council have looked to all possible sources of revenue to permit reconstruction of the damaged utility systems and the return of the utility

486. Order No. 667-A, *supra* note 261, at P 36.

487. Order No. 667-A, *supra* note 261, at P 36; 18 C.F.R. § 366.3(a).

488. 18 C.F.R. § 366.7. The Commission has not modified the procedure for certifying or self-certifying QF status. *See generally*, 18 C.F.R. Pt. 292.

489. FERC Documents and Filing, eLibrary – Docket Prefix Information, *available at* <http://www.ferc.gov/docs-filing/eLibrary/docket-prefix.asp> (last visited March 12, 2007).

to financial health. Among the financial resources used are property insurance, although since Hurricane Andrew, Gulf Coast utilities' access to property insurance has been greatly reduced. ENO estimates that insurance proceeds will cover only about \$250 of the \$700 million in insurable storm damage it incurred.

ENO hopes to receive about \$200 million of the Gulf Coast relief funds authorized by Congress in late 2005 and the Louisiana legislature in December 2006, although additional federal approval is required. ENO's limited storm reserve was used to cover storm damage incurred prior to Katrina and Rita, and was not large compared to the damage those hurricanes caused in any case. For the future, a compromise has been reached under which ENO ratepayers will fund a reserve of \$75 million over ten years. An important source of funds for ENO immediately after the hurricanes was a debtor-in-possession loan of approximately \$100 million under a bankruptcy court approved line of credit from its parent, Entergy. In addition, ENO has been allowed a modest increase in its rates which provides rate stability to New Orleans ratepayers and should allow ENO to regain its financial health.

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