REPORT OF THE ELECTRIC UTILITY REGULATION COMMITEE

I. INTRODUCTION

Over the past year, the Federal Energy Regulatory Commission (FERC or Commission) has issued a number of decisions that have significantly affected the evolution of regional transmission organizations (RTO) in the United States, as well as, decisions and policies that will have a significant impact on how competitive electricity markets continue to evolve. Since this Committee's last Report, the Commission has attempted to bring some order to RTO issues in the Midwest, and offered additional guidance (but no clear mandates) regarding RTO formation in other regions of the country. The Commission has also devoted significant time attempting to address a host of issues stemming from the 2000-2001 California energy crisis. The Commission has increased its emphasis on market monitoring and is in the process of establishing a new Office of Market Oversight and Investigation to perform market monitoring functions.

A number of critical electric utility regulation issues are emerging as of the date of this Report. These issues include the Commission's issuance of its Standard Market Design Notice of Proposed Rulemaking (SMD NOPR), the Commission's investigation into transactions in Western Power Markets during 2000 and 2001, and the Commission's ongoing effort to rationalize RTO development in certain regions of the country. The Committee will address these emerging issues in its next Report.

II. RTO ISSUES

A. *Midwest ISO / Alliance*

As 2001 began, the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) and the proposed Alliance Regional Transmission Organization (proposed Alliance RTO) both were seeking Commission approval to operate regional wholesale electricity markets alongside one another. The proposed Alliance RTO stretched from Illinois to Northeastern North Carolina originally encompassing a large swath of Midwestern and Mid-Atlantic utilities, including industry behemoths Commonwealth Edison Company and American Electric Power Service Corporation. The Midwest ISO covered the rest of the Midwest and included several Midwestern utilities, including Cinergy Corporation, Wisconsin Electric Power Company, and LG&E Energy Corporation. On August 31, 2001, proposed Alliance RTO member International Transmission Company (International Transmission), the transmission-only affiliate of DTE Energy Company (DTE) respectively, decided to depart the proposed Alliance RTO for the Midwest ISO.[1]

1. *See generally Int'l Transmission Co.*, F.E.R.C. Docket No. ER01-3000-000.

The FERC attempted to sort out the muddled Midwestern RTO picture in a group of five orders issued on December 20, 2001. In these orders, the Commission determined that the proposed Alliance RTO did not meet the Commission's scope and configuration requirements[2] and, therefore, rejected the proposed Alliance RTO application.[3] Additionally, the Commission approved the Midwest ISO's RTO application, making the Midwest ISO the first fully-approved RTO in the nation.[4] The FERC ordered the companies participating in the proposed Alliance RTO (Alliance Companies) to explore how the Midwest ISO could accommodate their business plan, and left the door open to the Alliance Companies to participate in other RTOs.[5]

The Commission also approved International Transmission's move to leave the proposed Alliance RTO and join the Midwest ISO.[6] International Transmission sought participation in the Midwest ISO as a stand-alone transmission company through Appendix I to the Midwest ISO Agreement. Appendix I allows independent transmission companies, companies unaffiliated with market participant assets such as generation, to participate in an RTO while retaining limited control over RTO functions. The Commission determined that until DTE's divestiture of International Transmission to a completely unaffiliated third party is complete, International Transmission could not take on RTO functions. But, once divestiture is complete, International Transmission will be able to take on responsibility, in coordination with the Midwest ISO, over a few limited RTO functions, such as local transmission planning, maintenance, and outage scheduling.[7] In a press release accompanying the issuance of the Commission's December 20, 2001 Midwest-related orders, the Commission suggested that the Alliance Companies could similarly participate in the Midwest ISO through Appendix I.[8]

On February 15, 2002, the Alliance Companies filed a petition for review in the United States Court of Appeals for the District of Columbia Circuit in Case No. 02-1061.[9] Meanwhile, the Alliance Companies pursued negotiations with both the Midwest ISO and PJM Interconnection, LLC. Negotiations between the Alliance Companies and the Midwest ISO reached an impasse, according to a March 6, 2002 petition for declaratory order filed by the Alliance Companies

2. 18 C.F.R. § 35.34 (2002).

3. Order on Requests for Rehearing, *Alliance Cos.*, 97 F.E.R.C. ¶ 61,327 (2001) [hereinafter December 20 Alliance Order].

4. Order Granting RTO Status and Accepting Supplemental Filings, *Midwest Indep. Transmission Sys. Operator, Inc.* 97 F.E.R.C. ¶ 61,326 (2001).

5. December 20 Alliance Order, *supra* note 3, at 62,531.

6. Order Accepting Agreements for Filing and Approving Transfer of Control Over Jurisdictional Facilities, Subject to Subsequent Filings, *Int'l Transmission Co.*, 97 F.E.R.C. ¶ 61,328 (2001).

7. *Id.* at 62,542.

8. *See generally* F.E.R.C. Press Release, *Commission Paves Way For Optimally Sized Midwest RTO* (December 19, 2001).

9. Their petition seeks review of the Commission's determination that, as of July 12, 2001, RTO start-up activities were to be overseen by an independent board. This determination was made in *Alliance Cos.*, 96 F.E.R.C. ¶ 61,052, *order on reh'g*, 97 F.E.R.C. ¶ 61,327 (2001). The FERC has filed a motion to dismiss for lack of jurisdiction and the D.C. Circuit has not yet ruled on the motion.

and National Grid (Alliance Petitioners).[10] In this petition, the Alliance Petitioners requested that the Commission make five findings:

(1) their proposed functional and operational relationship between the Midwest ISO and Alliance Gridco (the proposed independent transmission company with Alliance Companies' transmission assets controlled by National Grid serving as the Managing Member) forms a reasonable basis for the participation of Alliance Gridco within the Midwest ISO;
(2) Alliance Gridco should be permitted to use its own systems for the timely and cost-efficient start of operations;
(3) prices for services purchased by Alliance Gridco from the Midwest ISO should be priced at the Midwest ISO's reasonably-incurred incremental costs, subject to verification and audit;
(4) their proposed transition period rate design and revenue distribution methodology should be adopted for the Midwest ISO and Alliance Gridco; and
(5) the Midwest ISO should refund $60 million, plus interest, to Commonwealth Edison Company, Illinois Power Company and Ameren Corporation.[11]

On April 25, 2002, the Commission issued an order acting on the Alliance petition.[12] In this order and in a companion order,[13] the Commission gave its current views on the proper split of responsibilities between an RTO and an independent transmission company (ITC or transco). The Commission emphasized that "the decisions we are making today regarding the division of responsibilities between ITCs and RTOs are not set in stone. As we and the industry gain operating experience under the hybrid RTO model, this division of responsibility may evolve and additional opportunities may develop for ITCs."[14]

Administer Own Tariff. Alliance Petitioners had requested the authority for Alliance GridCo to maintain its own tariffs and a separate tariff controlling transactions into or out of the Alliance region. The Commission rejected their request to control transactions that required transmission outside the Alliance area. The Commission also decided not to allow Alliance GridCo to maintain its own tariff: "Multiple tariffs unnecessarily undermine the unity of the RTO region."[15] However, the Commission stated it would allow Alliance Petitioners GridCo to maintain separate schedules within the Midwest ISO's tariff "to facilitate different rates and a different rate design."[16]

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10. *See generally* F.E.R.C. Docket No. EL02-65-000.

11. These companies, originally part of the Midwest ISO, had paid a $60 million withdrawal fee to the Midwest ISO as part of the Illinois Power Settlement. *Illinois Power Co.*, 95 F.E.R.C. ¶ 61,183, *reh'g denied*, 96 F.E.R.C. ¶ 61,026 (2001).

12. Order on Petition for Declaratory Order, *Alliance Cos.*, 99 F.E.R.C. ¶ 61,105 (2002) [hereinafter April 25 Alliance Order].

13. Order Authorizing Disposition of Jurisdictional Facilities and Participation in the Midwest ISO Regional Transmission Organization, *Translink Transmission Co.*, 99 F.E.R.C. ¶ 61,106 (2002).

14. April 25 Alliance Order, *supra* note 12, at 61,430.

15. *Id.* at 61,434.

16. April 25 Alliance Order, *supra* note 12, at 61,434.

Propose/Submit Rate Filings. The Commission stated it would allow Alliance GridCo unilaterally to file rate structure and incentive rate proposals as part of a revenue request, after consultation with the Midwest ISO. The Commission noted that Appendix I to the Midwest ISO tariff currently does not require an ITC to consult with the Midwest ISO prior to filing rate proposals under Section 205 of the Federal Power Act (FPA).[17] However, the Commission said such consultation is important "to ensure that the Midwest ISO has adequate opportunity to review the filing and inform the Commission as to whether it results in adverse impacts either physically or financially" outside of the ITC's footprint.[18]

Congestion Management. The Commission rejected the Alliance Petitioners' proposal that Alliance GridCo would be responsible for managing congestion within the Alliance area, noting that it did not fully describe how congestion management would be coordinated between the Midwest ISO and Alliance GridCo.[19]

Parallel Path Flow. The Commission accepted Alliance Petitioners' proposal to share the responsibility for dealing with parallel path flows with the Midwest ISO "only when such flows lead to an emergency situation; however, action by Alliance during an emergency must adhere to the Midwest ISO's authority, that may take the form of protocols."[20]

System Control/Voltage Control/Regulation (Ancillary Services 1, 2, 3). Alliance GridCo proposed to "specify and pay for those ancillary services required to deliver a secure, reliable transmission system."[21] The Commission found this proposal vague, noting that Alliance Gridco needs to provide ancillary services 1, 2, and 3. The Commission referred Alliance Petitioners to the companion TRANSLink Order for more details.[22]

Open Access Same-time Information System (OASIS). The Commission rejected Alliance's proposal to operate its own node on the Midwest ISO's OASIS.[23] The Commission stated it would allow the Midwest ISO OASIS site to offer a site page to the respective ITCs' services.[24]

The Commission determined that the Alliance's proposal for available transmission capacity (ATC) and available flowgate capacity (AFC) calculations was acceptable, but that the Midwest ISO must provide the inputs for capacity benefit margin (CBM) and transmission reliability margin (TRM). The Commission approved, on an interim basis, the Alliance's proposed procedure for calculating ATC and AFC, subject to meeting criteria developed and determined by the Midwest ISO.[25]

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17. 16 U.S.C. § 824(d) (1994).
18. April 25 Alliance Order, *supra* note 12, at 61,435.
19. *Id.* at 61,436.
20. April 25 Alliance Order, *supra* note 12, at 61,437.
21. *Id.* at 61,438.
22. April 25 Alliance Order, *supra* note 12, at 61,438.
23. *Id.* at 61,435.
24. April 25 Alliance Order, *supra* note 12, at 61,435.
25. *Id.* at 61,440.

Market Monitoring. The Commission rejected the Alliance Petitioners' proposal for Alliance GridCo to impose and collect penalties for tariff violations.[26]

Planning and Expansion. The Commission rejected the Alliance Petitioner's proposal for the Alliance GridCo to be responsible for planning and expansion of its own systems, with the Midwest ISO responsible only for coordinating the ITCs' regional transmission plans. The Commission stated that "the Midwest ISO, as the RTO, should have the responsibility to ensure that planning and expansion is coordinated across the entire RTO."[27] The Commission stated "the RTO, not an outside arbitrator, must have the ultimate authority regarding planning and expansion for its region."[28]

The Commission directed the Alliance Petitioners and Midwest ISO to develop a coordinated approach to planning and "to include a joint planning protocol detailing each organization's responsibilities."[29]

Operational Authority. As a general matter, the Commission noted that although it was approving many aspects of the Alliance's proposal, Alliance GridCo would need to implement any necessary modifications to its operations to support LMP and any other aspects of SMD "on a unified, region-wide market basis."[30]

Generation and Transmission Outages. The Commission found Alliance Petitioners' proposal for the Alliance GridCo to control generation and transmission outages within its region, "subject to the Midwest ISO oversight for certain critical transmission facilities, [to be] a rational example of the type of coordination between the ITC and RTO that is needed."[31] The Commission stated that Alliance GridCo must coordinate approved maintenance schedules for generation and non-critical transmission with the Midwest ISO, so that the Midwest ISO can fulfill its reliability and security functions.[32]

Security Coordinator/NERC Reliability Authority. The Commission rejected the Alliance Petitioners' proposal to make Alliance GridCo responsible for security coordination within its area, with the Midwest ISO intervening only "if it determines that conditions within the Alliance area are impacting on security outside of the Alliance area" because "security coordination is simply too critical a function to vest in more than one entity."[33] The Commission cited seams problems as another reason for rejecting this proposal.

Beyond the slicing and dicing adjudications, the Commission also found the Alliance Petitioners' proposed rate design and revenue distribution methodology reasonable in concept, but emphasized that actual rates had not been filed. The Commission found reasonable in concept the Alliance Companies' proposed

26. April 25 Alliance Order, *supra* note 12, at 61,440.
27. *Id.* at 61,439.
28. April 25 Alliance Order, *supra* note 12, at 61,439.
29. *Id.*
30. April 25 Alliance Order, *supra* note 12, at 61,437.
31. *Id.* at 61,436.
32. April 25 Alliance Order, *supra* note 12, at 61,436.
33. *Id.* at 61,437.

revenue distribution methodology and stated that it "serves to remove disincentives to RTO participation."[34] The Commission found that the rates previously filed by the Alliance Companies were stale and must be updated. However, the Commission declined to establish a "blanket requirement that transmission owners file an updated cost-of-service analysis in order to justify their transitional surcharges since this would create an unnecessary impediment to RTO participation."[35] The Commission also emphasized that the proposed methodology would sunset in December 2004.[36]

Regarding the proposal to use systems developed by the Alliance Companies, the Commission stated that the Alliance Companies could work with the Midwest ISO in determining which systems could be used, but the Midwest ISO was given the ultimate authority on which systems to adopt. Regarding the Illinois Parties' claim for $60 million, the Commission stated that, if the Illinois Parties do in fact join the Midwest ISO, they could seek recovery of the $60 million, "provided that the Illinois Companies commit to pay their fair share of Midwest ISO's start-up costs."[37] The Commission clarified that the refunding of the $60 million would only be applicable if the Illinois Companies joined the Midwest ISO (and not some other RTO).

The Commission ordered the Alliance Companies to inform the Commission as to their plans for joining an RTO within thirty days of the issuance of its order.[38] Subsequently, on May 7, 2002, American Electric Power Services Corporation (AEP) entered into a Memorandum of Understanding with PJM to explore AEP's membership in PJM West. PJM is the Mid-Atlantic ISO and lies to the East and North of AEP and much of the Alliance and Midwest ISO footprint. On May 28, Commonwealth Edison Company, Illinois Power, and Dayton Power and Light announced that they are pursuing joining PJM as well. FirstEnergy, however, announced contrary plans to join the Midwest ISO. Dominion Virginia Power announced that it was still exploring its options. Michigan Electric Transmission Company, the transmission-only affiliate of CMS Energy, has since been sold to Trans-Elect, Inc., and Trans-Elect, Inc. announced that it would participate in the Midwest ISO.

Thus, at present the Midwestern RTO situation continues to remain muddled, with a third regional player— PJM, now drawn into the mix. The Commission expressed concern with these developments at its open meeting on May 30, 2002, and it remains to be seen what picture emerges in the remainder of 2002.

B. PJM/New York/New England[39]

The fast-changing events of 2002 have placed the PJM, New York, and

34. April 25 Alliance Order, *supra* note 12, at 61,446.

35. *Id.*

36. April 25 Alliance Order, *supra* note 12, at 61,444.

37. *Id.* at 61,450.

38. April 25 Alliance Order, *supra* note 12, at 61,450.

39. Unless otherwise indicated, the information and quotations provided in this section are taken from the notes of Gary Guy, who attended the Commission's meetings.

New England ISOs on different paths to expanding the scope and structure of their RTO formation efforts. As noted in the above section, certain Alliance member companies have indicated an intent to join PJM.[40] An advance indication of PJM's possible movement in other directions had been given in 2001, when Allegheny Power (Allegheny) was approved for membership into PJM as a separate "PJM West" region,[41] and the implementation of this approval moved forward in 2002. The New York and New England ISO's have been discussing a possible combination with the Ontario, Canada region as an alternative to a joint RTO that would include PJM.

As to the possibilities for administration of RTOs in the Northeast, by order issued on April 25, 2002, the Commission clarified that it has not yet decided whether National Grid USA (National Grid) is a market participant with respect to the New England and New York markets.[42] This ruling was made to clarify that the Commission's earlier finding[43] that National Grid was not a market participant for purposes of being eligible to be a managing member of the proposed Alliance RTO was not an indication of whether it would be able to take a similar active role in management or operation of a New York or New England RTO.

On May 28, 2002, a telephone conference was held between certain participating FERC commissioners, its staff, and Northeast commissioners concerning Northeast RTO development. The results of that conference were also reported to the Commission by the Staff at the May 30, 2002 Sunshine Act Meeting (May 30 Meeting). Among other things, the staff reported that PJM imports heavily from the Midwest and that it has capacity to import more from the Midwest than from New York. It reported that a combined New England/New York RTO would increase costs in New England and decrease costs in New York. The staff further reported that a three-way RTO that includes PJM would add costs to both New England and PJM and even more dramatically decrease costs to New York, by $367 million.

The staff stated that while some state commissioners want the FERC to proceed towards RTO formation, most commissioners believe that seams issues need to be resolved first. Chairman Maureen Helmer of the New York Public Service Commission was singled out for recommending that the Commission intercede in the RTO formation discussions to require that seams issues be resolved.

The FERC commissioner, Nora Mead Brownell, stated at the May 30 Meeting that she agreed with the need to resolve seams issues, but that the RTO

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40. These companies are Commonwealth Edison Company (ComEd), Illinois Power Company (Illinois Power), Dayton Power & Light Company (DP&L), American Electric Power Service Corporation, on behalf of Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company (collectively, AEP), and Virginia Electric and Power Company (VEPCO). *Alliance Cos.*, 100 F.E.R.C. ¶ 61,137, 61,522-4 (July 31, 2002). AEP, ComEd, DP&L, Illinois Power, and VEPCO stated their intent to collectively participate within an ITC operating under PJM or individually under PJM. *Id.* at ¶ 15.

41. *PJM Interconnection L.L.C.*, 96 F.E.R.C. ¶ 61,060 (2001).

42. *Nat'l Grid USA*, 99 F.E.R.C. ¶ 61,102 (2002).

43. *Nat'l Grid USA*, 97 F.E.R.C. ¶ 61,329 (2001).

process should continue to go forward. Commissioner William L. Massey indicated that he does not view a merger between the Northeast ISOs as off the table pending resolution of seams issues. Chairman Pat Wood III agreed, saying that he sees good reasons to "bring the two together, and maybe even the three."

As for the seams issues, Chairman Wood instructed the staff to call for the three ISOs, plus Midwest ISO, to make a presentation at the June 12, 2002 Sunshine Act Meeting (Sunshine Act Meeting) to lay out a timetable for resolution of seams issues, including dates by which to resolve planning, reliability, and rate issues. He indicated that if these seams issues get resolved, then it should be easier for these regions to implement whatever emerges from the Standard Market Design rulemaking.

At the June 12 Meeting, PJM defended the decision of AEP and other former Alliance members to join PJM. PJM's spokesperson stated that the Commission should be less concerned about geography of the RTO members because the more important consideration is the location of Extra High Voltage (EHV) areas. He pointed out that AEP is the link to the nation's heartland and that AEP's Memorandum of Understanding with PJM will start a process of intense discussions on bringing AEP into PJM's market. He stated that while the process was not yet underway because AEP was still talking to other Alliance members about joining PJM, he predicted that once the negotiations are underway, it will take forty to sixty days to get rate issues and procedures worked out so that a filing can be made with an implementation date for a market to be running in six to nine months.

He also said that PJM and Midwest ISO will have a "joint and common market" (an architecture overseeing the two RTOs' separate markets) by 2005. He further stated that the Commission needs to come out with its standard market design, and then the seams issues will be largely eliminated. Finally, the PJM official stated that there will be a single, large data base shared between PJM and Midwest ISO whereby the location of individual members will be insignificant.

The Midwest ISO spokesperson stated that the decisions of the Alliance members to divide up between joining PJM and Midwest ISO will create non-contiguous RTOs that will have difficulties with security coordination and reliability. For example, he stated that electricity will flow in and out of both RTOs to get to ComEd and that it will be difficult to dispatch from a generator without seams problems when both RTOs have to be involved.

According to the New York ISO presentation, many seams issues were resolved in 2001, more are being eliminated in 2002, and the problems will be all but eliminated in 2003. For example, he stated that in 2001 PJM added internal scheduling protocols, and New England ISO began reserve sharing with New York ISO, and New York ISO implemented block trading. In 2002, according to the New York ISO presenter, ICAP (installed capacity) can now be sold from and through all three ISOs, New York ISO implemented transaction rule changes, and New York ISO is about to implement prescheduling, whereby long term transmission with firm transmission rights will be a reality (whereas before, New York's financial rights made such long term planning unreliable because it differed from PJM's and New England's physical rights). New York also stated that the main goal now is for the Commission to come out with its final rule on standard market design.

The New England ISO stated that it is cloning its system to match that of PJM. It advocated elimination of border charges, stating that having markets the same within borders will not solve the problem if there are cost differences between them. The software can implement changes easily, according to the New England ISO speaker, but New England ISO supported having vendors make software changes only twice a year during off-peak periods on a nationwide basis, subject to FERC approval. The real need, continued the New England ISO representative, is for the Commission to provide another mechanism for transmission owners to recover the revenues they lose once the border charges are eliminated. New England ISO pointed to two cost-shifting features of eliminating pancaking. One is that the region that takes in the most load loses revenue (*i.e.*, PJM as opposed to Midwest ISO and Alliance). The other is that load dispatching decisions will change because of the change in cost consequences. This led the Commissioners to discuss the prospect of instigating a Section 206 proceeding under the Federal Power Act on whether to declare border, or "through and out," charges unjust and unreasonable. Additional presentations were made by these participants and/or representatives of National Grid and the North American Reliability Council (NERC) at the Commission meetings of June 26, 2002 and July 17, 2002.

Also, on June 18, 2002, the Commission issued a notice in Docket No. RT01-99 requesting further comments on a timeline and report by the Northeast ISOs on the resolution of seams issues among regional transmission organizations. On July 2, 2002, New York transmission owners filed a supplement to earlier filed comments requesting the Commission to find that there should be a single market in the Northeast and a coordinated technology development with respect to that market, rather than a single RTO.

By a July 3, 2002 delegation letter order, the Commission's Office of Markets, Tariffs, and Rates required the filing of information by the parties involved concerning the former Alliance companies' decisions to join PJM and reliability and operational information from, among others, the Mid-America Interconnected Network and East Central Area Reliability Coordination Agreement. On July 10, 2002, such information was submitted. On July 24, 2002, PJM also submitted a statement responding to an analysis previously submitted by the Midwest ISO concerning the RTO choices of the transmission owners that were formerly a part of the Alliance RTO.

By an order issued on July 31, 2002 (July 31 Order), the Commission conditionally accepted compliance filings by former Alliance companies, providing guidance on the Midwest ISO and PJM structure, and instituting a Section 206 investigation into the through and out charges between Midwest ISO and PJM.[44] The conditions contained in the July 31 Order are that: (1) what was referred to as a "single market" (paragraph 57) and a "functional common market" (paragraph 44) be formed between Midwest ISO and PJM by October 1, 2004; (2) PJM revise its tariff to permit ITCs to operate within PJM; (3) the

44. *Alliance Cos.*, 100 F.E.R.C. ¶ 61,137 (July 31, 2002).

delegation of functions by PJM to the ITCs to be operated by National Grid satisfy the delegation of functions provided for in two prior Commission orders;[45] (4) PJM file an agreement with National Grid, AEP, ComEd, and DP&L in which the latter parties indicate that they will form an ITC to which neither PJM nor Midwest ISO will belong; (5) NERC approve reliability plans; (6) a solution to through and out rates between Midwest ISO and PJM be developed; (7) AEP, ComEd, Illinois Power, Midwest ISO and PJM propose a solution to loop flow and congestion problems in Wisconsin and Michigan that will hold harmless utilities located in those states; (8) an implementation plan be filed and periodic reports thereafter showing how Midwest ISO and PJM will meet the October 1, 2004 common market date; and (9) that the Commission staff be involved in the process. In response to the July 31 Order's requirement that parties indicate their agreement to the conditions set forth therein, on August 15, 2002, Midwest ISO and PJM submitted separate statements so indicating, but stating that some of the interim dates established by the July 31 Order are too ambitious for the parties to reach. Still pending before the Commission is a June 25, 2002 filing by PJM of a Memorandum of Understanding between it, National Grid, and the Alliance companies that are intending to join PJM.

Meanwhile, with respect to the development of PJM West, on June 21, 2002, PJM supplemented a May 30, 2002 filing in Docket No. EL01-122 to incorporate in the PJM West Transmission Owner's Agreement the same changes that the Commission ordered to be made to the PJM Transmission Owners Agreement. On July 23, 2002, the Commission issued an order approving Allegheny's rate case settlement establishing a hold harmless mechanism to benefit Allegheny's wholesale customers through reduced network service rates.[46] This settlement facilitates Allegheny joining PJM West. On August 5, 2002, PJM filed revised tariff sheets to implement the settlement.

Finally, the PJM transmission owners prevailed in a court appeal of certain issues involved in the Commission's order approving PJM as an ISO. The United States Court of Appeals for the District of Columbia Circuit ruled in *Atlantic City v. FERC*[47] that the Commission may not compel transmission owners to cede their rights under section 205 of the Federal Power Act to file changes in rate design; that the FERC may not require the filing of a section 203 application to effectuate a withdrawal from PJM, and vacating the Commission's generic modification of a grandfathered contract of one of the transmission owners for failure to make proper findings under the public interest standard applicable to fixed rate contracts under the *Mobile-Sierra* doctrine.[48] In the August 15, 2002 filings by Midwest ISO and PJM discussed above, whereby they indicate that they will comply with the July 31 Order's condition concerning addressing through and out charges between Midwest ISO and PJM, both entities referenced the rights of the transmission owner to unilaterally

45. *Alliance Cos.*, 97 F.E.R.C. ¶ 61,327 (2001); *TRANSLink Transmission Co.*, 99 FERC ¶ 61,106 (2002).

46. *PJM Interconnection*, 100 F.E.R.C. ¶ 61,088 (July 23, 2002).

47. *Atlantic City v. FERC*, 295 F.3d 1 (D.C. Cir. July 12, 2002).

48. United Gas Pipe Line Co. v. Mobile Gas Serv. Corp., 350 U.S. 332, and Federal Power Comm'n v. Sierra Pacific Power Co., 350 U.S. 348 (1956).

submit section 205 rate change filings per the *Atlantic City* decision as being a means by which to address this issue.

C. RTO West

On April 26, 2001, the Commission issued an order (April 26 Order) that modified and granted on a preliminary basis a request for declaratory orders filed by the RTO West applicants in connection with their RTO proposal.[49] The April 26 Order also rejected the proposed Form of Agreement Limiting Liability among RTO West Participants, and deferred consideration of numerous issues with respect to the establishment of RTO West and the ITC TransConnect.[50] On July 12, 2001, the Commission issued an order (July 12 Order), which granted in part and denied in part rehearing of its April 26 Order.[51]

The initial portion of the July 12 Order addressed rehearing issues related to the RTO West governance proposal. The Commission clarified that "where a cooperative has transmission assets of its own it should be permitted representation in the ISO portion of RTO West."[52] The Commission also denied the challenge of the Consumer-Owned Utilities[53] to the RTO West proposal's bifurcated voting structure for transmission-dependent utilities, which weights the voting in the transmission dependant utility class in a manner that gives more weight to larger utilities and less to smaller utilities.[54] The Commission stated that the bifurcated voting structure for the Transmission Dependent Utility (TDU) class "is reasonable to afford a balanced representation for all members of that class."[55]

With respect to the independence of the RTO West trustees and RTO West employees, the Commission rejected a series of challenges to the RTO West Trustee Code of Conduct and the RTO West Employee Code of Conduct. Specifically, the Consumer-Owned Utilities argued that the RTO West Trustee Code of Conduct and bylaws fail to ensure that the RTO will be governed by individuals that are free from a personal financial stake in entities whose financial performance will depend on the actions of RTO West. They also argued that the RTO West Employee Code of Conduct allows employees to hold a financial stake in transmission-only companies, scheduling coordinators, or distribution-only companies in a manner that could affect decisions made by

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49. *See generally Avista Corp.*, 95 F.E.R.C. ¶ 61,114 (2001). The RTO West applicants are Avista Corporation, Bonneville Power Administration, Idaho Power Company, Montana Power Company, Nevada Power Company, PacifiCorp, Portland General Electric Company, Puget Sound Energy, Inc., and Sierra Pacific Power Company.

50. The companies proposing to form TransConnect are Avista Corporation, Montana Power Company, Nevada Power Company, Portland General Electric Company, Puget Sound Energy, Inc., and Sierra Pacific Power Company.

51. *Avista Corp.*, 96 F.E.R.C. ¶ 61,058 (2001).

52. *Id.* at 61,173.

53. The Consumer-Owned Utilities are the Idaho Consumer-Owned Utilities Association, Idaho Energy Authority, Market Access Coalition, Northwest Requirements Utilities, Public Utility District No. 1 of Snohomish County, Washington, Western Public Agencies Group, and Public Power Council.

54. 96 F.E.R.C. ¶ 61,058, at 61,174.

55. *Id.*

those employees. The Commission rejected the first argument with respect to the Trustee Code of Conduct by focusing on the definition of "market participant" in that code of conduct.[56] According to the Commission:

> [s]ince the definition of market participant . . . includes entities whose interests would be significantly affected by the decisions by RTO West, and the Trustee Code of Conduct reinforces the requirement that Trustees must be free from a personal financial interest in entities whose financial performance will depend on the actions of RTO West, the Trustee Code of Conduct does not require revision as requested by Consumer-Owned Utilities.[57]

The Commission rejected the argument with respect to the Employee Code of Conduct in the same manner, stating that "[t]he RTO West Employee Code of Conduct . . . adopts the Commission's definition of market participant, thereby ensuring that RTO West employees may not have a financial interest in entities whose interests would be significantly affected by the decisions of RTO West."[58]

The final issue addressed by the Commission with respect to the RTO West governance proposal was whether the RTO West filing had unreasonably modified the stakeholder Board Advisory Committee, which was intended to govern the RTO along with a non-stakeholder Board of Trustees. The Consumer-Owned Utilities argued that the RTO West filing had "reduced the [originally-intended] scope of the Board Advisory Committee's powers and watered down its functions."[59] The Commission rejected that argument, stating that the "RTO West Applicants' proposal . . . meets the independence standards of Order No. 2000 . . . [and] Petitioners have not shown otherwise."[60]

The next portion of the July 12 Order addressed certain rehearing and clarification requests with respect to the April 26 Order's rulings on the ability of transmission owners to submit filings under Section 205 of the Federal Power Act.[61] Specifically, the April 26 Order permitted TransConnect to submit unilateral Section 205 filings to the Commission incorporating incentive or performance-based rates as part of its revenue requirement.[62] The April 26 Order also required the RTO West applicants to revise the Transmission Operating Agreement to eliminate the authority of transmission owners that are not independent of market participants to unilaterally make section 205 rate filings.[63] Idaho Power and PacifiCorp both sought rehearing of the prohibition on unilateral rate filings by transmission owners that are not independent of market participants. Deseret Generation and Transmission Cooperative sought clarification that transmission owners other than TransConnect are eligible to receive incentive rates under the RTO West structure.

In the July 12 Order, the Commission denied the requests for rehearing and clarification. The Commission pointed out that "Order No. 2000 makes clear

56. 96 F.E.R.C. ¶ 61,058, at 61,175.

57. *Id.*

58. *Avista Corp.*, 96 F.E.R.C. ¶ 61,058 (2001).

59. *Id.*

60. 96 F.E.R.C. ¶ 61,058, at 61,176.

61. 16 U.S.C § 824(d) (2002).

62. *Avista Corp.*, 96 F.E.R.C. ¶ 61,058 (2001).

63. 96 F.E.R.C. ¶ 61,058, at 61,339.

that the RTO has the exclusive right to administer its tariff and to make incentive rate filings with the Commission."[64] According to the Commission, the only reason that such a right was granted to TransConnect was that TransConnect "is independent of market participants . . . and is required under the Transmission Operating Agreement to consult with RTO West prior to proposing any incentive rate mechanisms."[65] The Commission emphasized that the basic rule is that "individual transmission owners must coordinate with the RTO and the RTO must make such [rate] filings."[66]

The July 12 Order next addressed rehearing issues with respect to the scope of RTO West. Valley Electric Association argued that the Commission erred in including Nevada Power as part of RTO West, pointing out that Nevada Power and Sierra Pacific are part of two separate, non-interconnected control areas. Consumer-Owned Utilities and the City of Seattle, in turn sought rehearing of the directive in the April 26 Order that the RTO West utilities work toward the establishment of a west-wide RTO. The Commission rejected both arguments. With respect to the inclusion of Nevada Power in RTO West, the Commission stated that the participation of both Nevada Power and Sierra Pacific in RTO West would reduce the per-unit uplift charge and thus increase efficiency.[67] The Commission also noted that "Nevada Power will contribute to RTO West's ability to satisfy its required functions of supporting efficient and non-discriminatory power markets."[68] With respect to the development of a single, west-wide RTO, the Commission emphasized that the problems with the California markets "leave no doubt of the interstate nature of the electric systems in the Western Interconnection."[69] Thus, the Commission again directed the RTO West applicants "to continue working toward the common goals of minimizing seams issues, improving inter-regional coordination, and ultimately establishing a single West-wide RTO."[70]

Finally, the July 12 Order addressed the rehearing argument of the RTO West applicants with respect to the Commission's rejection of the Form of Agreement Limiting Liability among RTO West Participants in the April 26 Order. The RTO West applicants had argued that the structure of an RTO precludes exclusive reliance on state law to protect against liability claims, that the liability limitation agreement was broadly supported in the stakeholder process, and that the liability limitation agreement tracks the currently effective Agreement Limiting Liability Among Western Interconnected Systems.

The Commission granted rehearing in part, and accepted the RTO West applicants' proposal to the extent that it allocates liability risks among transmission owners and the RTO.[71] The Commission stated that "[t]he transmission owners entered into a collaborative process that resulted in the

64. 96 F.E.R.C. ¶ 61,058, at 61,177.

65. *Id.*

66. 96 F.E.R.C. ¶ 61,058, at 61,177.

67. *Avista Corp.*, 96 F.E.R.C. ¶ 61,058, at 61,179 (2001).

68. *Id.*

69. 96 F.E.R.C. ¶ 61,058, at 61,179.

70. *Id.*

71. 96 F.E.R.C. ¶ 61,058, at 61,181.

allocation of liability risks among themselves and we conclude that this risk sharing is acceptable."[72] Nevertheless, the Commission stated that it would "not accept the RTO West Applicants' proposal to the extent it seeks to limit the rights of transmission customers and other third parties."[73] The Commission stated that "[t]he parties on rehearing have failed to demonstrate that the states no longer have the ability to address liability issues and that there is any need to depart from the findings made in Order No. 888 and upheld by the Court of Appeals for the District of Columbia Circuit."[74] Thus, the Commission directed the RTO West applicants to submit a compliance filing in accord with the Commission's determination on the liability issue within thirty days of the issuance of the July 12 Order.[75]

On July 25, 2001, the RTO West applicants filed a response to the July 12 Order stating that it is premature to require the submission of a compliance filing with respect to the proposed liability limitation agreement because the July 12 Order only dealt with a request for a declaratory order, and because the RTO West applicants had not yet made any filings with the Commission pursuant to sections 203 or 205 of the Federal Power Act.[76] On August 13, 2001, the RTO West applicants filed a request for rehearing of the July 12 Order that made the same arguments. On September 12, 2001, the Commission issued an order clarifying that in light of the fact that the July 12 Order only dealt with a request for a declaratory order, the RTO West applicants are not required to submit a compliance filing.[77]

C. Southeast RTO

On July 12, 2001, the Commission issued a series of orders dramatically affecting RTO development in the Southeast. The Commission determined that the public utilities in the region should participate in a single RTO for the Southeast and, based on that determination, ruled that existing RTO proposals were not of sufficient scope and configuration.[78] In conjunction with those orders, the Commission also ordered the Southeast public utilities (Entergy, the Southern Companies, Duke Energy Corporation, Carolina Power & Light

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72. *Avista Corp.*, 96 F.E.R.C. ¶ 61,058, 61,181 (2001).

73. *Id.*

74. 96 F.E.R.C. ¶ 61,058, at 61,182. In Order No. 888, the Commission distinguished liability from indemnification, and stated that the indemnification provisions of an open-access transmission tariff "should not be construed as preempting the appropriate tribunal's consideration of whether liability should attach for acts or omissions of the transmission provider that injure third parties." Order No. 888-B, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities*, 81 F.E.R.C. ¶ 61,248 (1997). The D.C. Circuit upheld this provision of Order No. 888, stating that the Commission's ruling "does not preclude the states from shielding utilities from liability for ordinary negligence. States did so before, through both their regulatory commissions and their courts; and they remain free to do so under Order 888." Transmission Access Policy Study Group v. FERC, 225 F.3d 667, 729-30 (D.C. Cir. 2000).

75. 96 F.E.R.C. ¶ 61,058, at 61,183.

76. 16 U.S.C. §§ 824(b), 824(d) (2002).

77. *Avista Corp.*, 96 F.E.R.C. ¶ 61,265, 62,018 (2001).

78. *GridSouth Transco, LLC*, 96 F.E.R.C. ¶ 61,067 (2001); *Southern Co. Servs., Inc.*, 96 F.E.R.C. ¶ 61,064 (2001); and *Southwest Power Pool*, 96 F.E.R.C. ¶ 61,062 (2001).

Company, and South Carolina Electric & Gas Company) as well as the Southwest Power Pool (SPP) to participate in a mediation before a Commission-appointed ALJ to explore the formation of a Southeast RTO.[79] The mediation took place during August and September of 2001, and culminated with a report submitted by ALJ Bobbie J. McCartney.[80] Judge McCartney recommended that the Commission adopt the "Grid Model," one of two competing proposals that came out of the mediation, which would create an independent, for-profit transco to serve as the RTO with an Independent Market Administrator that initially would (i) administer Southeastern markets, (ii) exercise functional control over the transmission system, (iii) operate OASIS and calculate ATC and TTC, (iv) process requests for transmission service, and (v) serve as security coordinator. As of the date of this article, the Commission had not acted on the Mediation Report.

Following the mediation, the Southern Companies joined forces with Entergy and several public power transmission owners to continue development of the SeTrans RTO (SeTrans) proposal.[81] On June 27, 2002, the SeTrans sponsors filed a petition for declaratory order approving as consistent with Order No. 2000 (i) a governance structure under which the SeTrans RTO would be managed by an Independent System Administrator (ISA), and (ii) the stakeholder process by which the ISA is to be chosen.[82]

Under the SeTrans proposal, the ISA would be an independent third-party entity, one with an existing management structure already in place that would provide management services to operate and manage the RTO, but would not own or invest in transmission facilities in the SeTrans region. The ISA would perform the requisite Order No. 2000 RTO functions (except for market monitoring, which would be done by an independent entity selected by the stakeholders) pursuant to a System Administrator Retention Agreement (SARA). The SARA would have an initial five-year term, with provisions for continuation or termination based on determinations made by the participating transmission owners (TOs). The sponsors envision that the SARA will provide the ISA with profit incentives to promote "cost-effectiveness, reliability and market efficiency."[83]

In conjunction with the SARA, each TO would enter into a Transmission

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79. Order Initiating Mediation, *Reg'l. Transmission Orgs.*, 96 F.E.R.C. ¶ 61,066 (2001). The utilities sponsoring GridFlorida LLC (Florida Power Corporation, Florida Power & Light Company, and Tampa Electric Company) were invited, but not required, to participate in the mediation.

80. Mediation Report for the Southeast RTO, *Reg'l. Transmission Orgs.*, 96 F.E.R.C. ¶ 63,036 (2001).

81. In addition to Southern and Entergy, the SeTrans sponsors are Cleco Power LLC; Dalton Utilities; Georgia Transmission Company; JEA; MEAG Power; Sam Rayburn G&T Electric Cooperative, Inc.; South Carolina Public Service Authority; South Mississippi Electric Power Association; and the City of Tallahassee, Florida. The sponsors state that the SeTrans RTO would consist of $9.3 billion of investment in some 54,000 miles of transmission lines rated 44 kV and above, of which over $2.1 billion and more than 11,000 miles are cooperatively or publicly-owned facilities.

82. The SeTrans sponsors state that the various RTO documents were submitted for informational purposes only to demonstrate the progress that had been made as of the date of the filing and to support a finding that the proposed governance structure and business model are consistent with Order No. 2000.

83. *Petition for Declaratory Order Concerning the Proposed SeTrans RTO.* Docket No. EL02-101-000, at 17 (F.E.R.C. docketed June 27, 2002).

Operating Agreement (TOA) that would set out the terms under which the ISA would exercise functional control of the TO's transmission assets and collect revenues under the SeTrans Open Access Transmission Tariff (OATT) sufficient to recover the TO's transmission revenue requirements. The TOAs would contain termination provisions to enable non-jurisdictional TOs to withdraw from SeTrans, without prior Commission approval, as they deem necessary to protect their tax-exempt status.

Finally, the SeTrans sponsors seek approval of the process by which they intend to select the ISA. Initially, a Stakeholder Advisor Committee (SAC) consisting of representatives from all sectors of the industry issued requests for qualifications. The SAC selected four potential candidates in April 2002, from which the sponsors will select the ISA. The sponsors project that they will complete the selection process by the Fall of 2002, after which the executed agreements will be submitted to the Commission.

II. NOTICE OF PROPOSED RULEMAKING REGARDING GENERATION INTERCONNECTION

Comments are pending before the Commission on an April 24, 2002 Notice of Proposed Rulemaking (NOPR) concerning the establishment by the Commission of a model uniform Interconnection Agreement and Interconnection Procedures for the interconnection of generation facilities to wholesale electric transmission systems.[84] Also pending before the Commission is a separately drafted and filed set of generation interconnection procedures and agreement submitted by the PJM RTO following a stakeholder approval process that would be applicable solely to the PJM region.

The NOPR is concerned with how accurate interconnection studies are timely produced, the extent to which transmission data should be made publicly available, creating proper incentives for transmission providers to treat all generation comparably, the equitable allocation of costs and benefits of siting generation, and determining who should pay for system upgrades associated with generation interconnection.[85] The Commission found a need to provide for such standardization because of widespread complaints by generators of difficulty in securing interconnection, receiving incomparable treatment from that received by transmission providers' own generation, system upgrade costs unrelated to the generation interconnection, delays in meeting deadlines, and lack of transparency of transmission information.[86]

The standardized procedures and agreement would be required as amendments to the open access transmission tariffs of public utilities that own, operate, or control transmission facilities under the Federal Power Act.[87] The NOPR proposes to include as interconnection facilities "all facilities . . . found

84. Notice of Proposed Rulemaking, *Standardization of Generator Interconnection Agreements and Procedures*, 99 F.E.R.C. ¶ 61,086, 67 Fed. Reg. 22,250 (2002) (codified at 18 C.F.R. pt. 35) [hereinafter *Standardization of Generator Interconnection*].

85. *Id.*

86. *Standardization of Generator Interconnection*, *supra* note 84, at 22,251.

87. *Id.*

between the generator and the grid connection."[88]

The NOPR made a judgment call on issues on which a consensus was not reached as a result of industry-wide participation in meetings on the basis of an Advanced Notice of Proposed Rulemaking (ANOPR) dealing with the same subject matter. Among the disputed issues and the proposed resolutions are the following: (1) to the extent that other systems are affected by the proposed interconnection of a generator, the third party should be required to coordinate interconnection study and network upgrades with the transmission provider;[89] (2) the transmission provider should bear the costs of accelerating the construction schedule if the acceleration is undertaken for the benefit of the transmission provider or that of another generator without consulting the generator;[90] (3) small generators should be responsible for all studies and upgrades needed to accommodate their facilities;[91] (4) regional variations will be considered as appropriate;[92] (5) transmission providers will be entitled to reimbursement if generator funding for construction of interconnection facilities are considered taxable events to transmission providers;[93] (6) interconnection agreements should be signed by three parties if the transmission owner is a separate entity from the transmission provider (as in the case of a utility within an RTO);[94] and (7) the transmission provider is liable for liquidated damages if it fails to meet any of its obligations under the interconnection procedures and does not remedy the failure within fifteen business days.[95]

Also, unlike the announced plan in the ANOPR, the Commission stated in the NOPR that it is taking up pricing issues all in a single document rather than through issuance of a second NOPR. This action is being taken because the commentors on the ANOPR convinced the Commission that parties could only take positions on such issues as siting and control within the context of how costs will be assigned.[96]

Existing pricing methods are the baseline, whereby the cost of network facilities cannot be directly assigned even if they would not have been installed but for a particular customer's service on the theory that all users benefit from such construction due to the integrated nature of the grid.[97] With unbundling, however, the Commission regards generation facilities to be non-network transmission facilities for which the generator does bear direct cost responsibility.[98] The facilities interconnecting the grid to the generation facility are considered sole use facilities to be removed from the transmission charge and

88. *Standardization of Generator Interconnection*, *supra* note 84, at 22,252.

89. *Id.* at 22,253.

90. *Standardization of Generator Interconnection*, *supra* note 84, at 22,253.

91. *Id.*

92. *Standardization of Generator Interconnection*, *supra* note 84, at 22,253-54.

93. *Id.* at 22,254.

94. *Standardization of Generator Interconnection*, *supra* note 84, at 22,254.

95. *Id.* at 22,268-9.

96. *Standardization of Generator Interconnection*, *supra* note 84, at 22,255.

97. *Id.* at 22,250.

98. *Standardization of Generator Interconnection*, *supra* note 84, at 22,250.

directly assigned.[99]

However, transmission credits are often given to generators once transmission service is rendered to prevent the generator from paying twice if some network upgrade facilities were assessed prior to transmission delivery service.[100] The Commission is open to considering alternatives to this pricing approach, and specifically requested comments on departures from its current pricing when independent entities such as RTOs are involved, particularly in light of the locational marginal pricing methodology under consideration in the Standard Market Design proceeding.[101]

On the separate PJM generation interconnection proceeding, on May 17, 2002, the Commission issued an order suspending PJM's filing for five months in order to make comparison of PJM's filing with whatever is finally determined on related matters in the generic ruling proceeding.[102] That suspension period will expire in November of 2002, by which time the Commission should have finalized its determinations in the NOPR proceedings.

III. TARIFFS, STANDARD MARKET DESIGN, AND MARKET MONITORING

A. Independence of Market Monitoring

The Commission has made large strides in developing a more comprehensive approach to market monitoring, primarily through release of the Standard Market Design Working Paper (SMD Working Paper). The SMD Working Paper lists general principles intended to "guide the development of market power mitigation rules and a market monitoring plan, as well as some specific measures that should be included in the standard market design."[103] Additionally, the Commission has addressed market monitoring-related issues in other contexts: granting approval to the Midwest ISO as an Order 2000 compliant RTO; requiring ongoing tinkering with the New York Independent System Operator (NYISO) market monitoring framework; and ratcheting up investigations of energy trading strategies in California following revelations that several generators and energy brokers engaged in strategies designed to artificially inflate energy prices and profit from phantom congestion. Altogether, the FERC has provided RTO/ISO participants with the broad outlines of what an acceptable market monitoring unit (MMU) will be expected to do, and indicated some of the tools that are at an MMU's disposal.

The Commission foresees regional MMUs as addressing two general areas: identification of market design flaws and monitoring market participant behavior. In the SMD Working Paper, the FERC stated that market design flaws have been at the root of many generation market problems in the first few years

99. *Id.* at 22,256.

100. *Standardization of Generator Interconnection*, *supra* note 84, at 22,255.

101. *Id.* at 22,256

102. *PJM Interconnection, L.L.C.*, 99 F.E.R.C. ¶ 61,189 (2002).

103. *Working Paper on Standard Transmission Service and Wholesale Electric Mkt. Design*, RM01-12-000, at 22 (F.E.R.C. docketed on March 15, 2002) [hereinafter *Working Paper*].

of ISO operations.[104] Better designed markets and adoption of best practices via the Standard Market Design are intended to eliminate many of these early problems. However, the Commission is further relying on MMUs to proactively identify market design flaws and propose market rule changes. "Market monitoring should serve as an early warning system for events that are not yet severe, so corrective action can be taken before exercises of market power become significant and sustained."[105]

In reviewing market participant behavior, the FERC expects the MMU to monitor for physical withholding and economic withholding. While the Commission retains for itself ultimate responsibility for monitoring wholesale electricity markets and the authority for corrective action, the FERC views the MMUs as the first line of defense against market participants' bad behavior.

1. MMU Guiding Principles

The SMD Working Paper lists a number of guiding principles, monitoring measures and mitigation measures to achieve the MMU goals. The FERC states that the list is intended to reflect the best practices observed in recent years that are compatible with other elements of the standard market design proposal.[106]

(a) Market rules should improve the markets' competitive structure, facilitate new entry and increase demand response.

(b) The regional planning process should: (i) identify opportunities for increasing competition and (ii) facilitate new demand response, transmission or generation construction as needed.

(c) Mitigation rules should be clear and not subject to discretionary actions.

(d) Market rules should not require offers to sell below marginal opportunity costs of a unit.

(e) Market monitoring should detect economic and physical withholding and assess market efficiencies.[107]

2. MMU Monitoring Measures

(a) Each RTO's MMU should be independent of RTO management. The MMU should be funded by the RTO, but report directly to the Commission and the RTO's independent governing board.

(b) MMUs will monitor all regional markets principally for economic and physical withholding.

(c) MMUs will assess the general performance of the markets and the impact of market rules, and will propose rule changes, when appropriate, to the Commission. The Commission will exercise oversight of MMU activities and the impact of RTO operations on the efficiency and effectiveness of the market.

(d) MMUs should work with each other, the states, and the Commission to

104. *Id.* at 2.

105. *Working Paper*, *supra* note 103, at 22.

106. *Id.*

107. *Working Paper*, *supra* note 103.

develop market performance measures that are common to all regions.[108]

3. MMU Mitigation Measures

(a) A bid cap must be in effect until sufficient demand response develops; mitigation rules limiting bid flexibility are also needed. As price-responsive demand develops, mitigation rules can be reduced correspondingly.
(b) The transmission provider may identify generating units that must-run for reliability. Bids submitted by these units should be subject to mitigation. Market power in load pockets must be mitigated with ongoing behavioral mitigation, such as call options or bid caps, unless structural solutions are possible.
(c) Limits on the flexibility to change bids, e.g., start-up costs, may be needed.
(d) The transmission provider must be able to coordinate maintenance and outage schedules for generation and transmission facilities. Information on maintenance and outage schedules should be made available to the market on a timely basis.[109]

B. *FERC Orders on Market Monitoring Models*

1. Midwest ISO

In a December 20, 2001 Order,[110] the FERC granted a market monitoring plan jointly submitted by the Midwest ISO, the Alliance Companies and Southwest Power Pool (SPP) subject to specific FERC-ordered changes and with two provisos: (i) that the plan may require future modification to conform to the Commission's still developing Standard Market Design,[111] and (ii) that the Commission will periodically assess the need for, and degree of market monitoring, and as a result may issue supplemental orders regarding the Midwest ISO's market monitoring plan.[112]

The regional plan calls for an Independent Market Monitor (IMM) to monitor the conduct of market participants, the transmission owners and the participating three RTOs that submitted the plan. The IMM's principal goal is to detect attempts to exercise market power in the participating RTO's administered markets;[113] and detect attempts to reduce the quantity or quality of transmission service in the region. Following are several of the market monitoring plan's key

108. *Id.* at 23.

109. Working Paper, *supra* note 103, at 23.

110. *Midwest Indep. Transmission Sys. Operator, Inc.*, 97 F.E.R.C. ¶ 61,326 (2001).

111. *Id.* at 61,518.

112. 97 F.E.R.C. ¶ 61,326, at 62,519.

113. The IMM will not generally monitor bilateral energy or capacity markets, nor will it monitor private transmission rights not administered, coordinated or facilitated by the participating RTOs. However, the contract between the IMM and the RTOs specifies that the IMM will address external markets or factors to the extent that they significantly affect the performance of the RTOs' markets or services. *See generally Compliance Electric Rate Filing, Retention Agreement* between the *Midwest ISO*, Alliance Companies and Southwest Power Pool and Potomac Economics ER02-108-003, at Attachment A (F.E.R.C. docketed January 17, 2002).

provisions.

The IMM must issue annual reports and other periodic reports as necessary or requested by the RTOs' Market Monitoring Committee[114] (MMC), the FERC, and the relevant state regulatory commission. The IMM may, at any time, bring any matter to the attention of the MMC, the FERC or relevant state regulatory commissions. The IMM has the responsibility to recommend to the RTOs modifications to market rules or tariffs, or other corrective actions to improve competitiveness or efficiency in RTO-operated markets. The IMM is to have virtually unfettered access to RTO information and the IMM may require that market participants and transmission owners turn over information falling under four broad headings: (i) production costs;[115] (ii) opportunity costs;[116] (iii) generating logs;[117] and (iv) transmission logs,[118] subject to confidentiality provisions.[119] The IMM must provide market participants and other interested parties an opportunity to comment on new indices and screens for reviewing data or other information, however, the IMM is not prevented from conducting further or different review or evaluations of data or information as the IMM deems appropriate to carry out the plan's goals. Lastly, the FERC, state regulatory commissions and any market participant may submit information to the IMM concerning a matter relevant to the IMM's responsibilities and furthermore, may request an investigation by the IMM related to the information submitted.

The FERC required only a few changes to the market monitoring plan as submitted: (i) the plan must be re-filed as an attachment to the Midwest ISO tariff and any proposed changes must be approved by the Commission because the terms of the plan are integral to the Midwest ISO's continued compliance with Order No. 2000 requirements for this function,[120] (ii) Midwest ISO must submit to FERC its contract with the proposed IMM to ensure that the IMM is truly independent of the RTO,[121] and (iii) the Midwest ISO must face a forty-five day deadline to either agree to implement an IMM recommendation or explain

114. The MMC consists of one representative appointed by each RTO.

115. Data relating to the costs of operating a specified Electric Facility (for generating units such data shall include heat rates, start-up fuel requirements, fuel purchase costs, environmental costs, and operating and maintenance expenses).

116. Data relating to regulatory, environmental, technical, or other restrictions that limit the run-time or other operating characteristics or a generating unit.

117. Data relating to the operating status of a generating facility, including generator logs showing the generating status of a specified unit. Such data shall include any information relating to a forced outage or deterioration of a generating unit.

118. Data relating to the operating status of a transmission facility, a contingency, or other operating consideration. This shall include data related to any generating units called out-of-merit or dispatched under any other operating order from the RTO or a control area operator.

119. Market participants and transmission owners may not contest the right of the IMM to obtain such data or information except to the extent that the party has a good faith basis to assert that the data or information Is not included in any of the categories on the list. *See generally* Retention Agreement ER02-108-003, at Attachment A (F.E.R.C. docketed January 17, 2002).

120. *Midwest Indep. Transmission Sys. Operator, Inc.*, 97 F.E.R.C. ¶ 61,326, 61,518 (2001).

121. *Id.*

why an IMM recommendation lacks merit.[122] Intervenors had one principal concern rebuffed by the FERC. The plan specifically denies the IMM authority to impose sanctions, penalties or fines. The FERC accepted this restriction on the basis that Order No. 2000 allows, but does not require, market monitors to have the authority to impose penalties and sanctions.[123] Thus, the plan's proposal for the IMM to have authority to make recommendations for corrective action is consistent with Order No. 2000.

2. New York Independent System Operator (NYISO)

In March 2002, the NYISO submitted a comprehensive market mitigation plan[124] that builds upon its existing conduct and impact approach. This framework applies a two-part test to determine when bids should be mitigated. The conduct test identifies whether the owner or operator of an electric facility may be engaging in illicit behavior, specifically conduct that is "(1) significantly inconsistent with competitive conduct; and (2) would result in a material change in one or more prices in a New York Electric Market."[125] Generally, the NYISO considers a market participant's conduct to be inconsistent with competitive conduct if the conduct would not be in the economic interest of the market participant in the absence of market power. Categories of conduct that the NYISO market monitor pays particular attention to are (i) physical withholding of an electric facility (not offering available service through a false outage, refusing to bid when it is economic to do so or operating in real-time at less than the dispatch instruction); (ii) economic withholding of an electric facility (submitting unjustifiably high bids); and (iii) uneconomic production from an electric facility (raising production levels to uneconomic levels to cause a transmission constraint).

If an owner or operator fails the conduct test, the impact test still must be applied to determine if the behavior has an actual material impact on market outcomes. A material impact in price is defined as an increase of 200% or $100 per MWh, whichever is lower, in the hourly day-ahead or real-time locational market price at any location, or of any other price in a New York electric market administered by the NYISO.

Several other changes to the mitigation plan include: (i) adoption of measures to address the locational market power issues in New York City by applying lower thresholds to generation in New York City that vary depending on the frequency of congestion, (ii) adding thresholds for monitoring and mitigation for non-price bid parameters that may be used to withhold resources from the market, (iii) several refinements to the automated mitigation procedures to improve the focus and effectiveness of the procedures,[126] (iv) adoption of

122. 97 F.E.R.C. ¶ 61,326, at 61,519.

123. *Id.*

124. *Compliance Filing of the New York Indep. Sys. Operator, Inc., Regarding Comprehensive Mkt. Mitigation Measures and Request for Interim Extension of Existing Automated Mitigation Procedure*, ER01-3155-000 (F.E.R.C. docketed March 20, 2002).

125. *Id.* at Attachment 1, First Revised Sheet No. 467.

126. The Automated Mitigation Procedures (AMP) do not create new mitigation standards, rather the AMP automates the applications of the relevant conduct and impact thresholds to eliminate the one-day lag

specific conduct thresholds for non-price bid parameters, (v) implementing a limited exemption from mitigation measures for new generation, which recognizes the competitive benefits that new generation provides to the system while reducing any disincentives to new generation, and (vi) improvements to Consolidated Edison of New York, Inc.'s in-city Day Ahead Market mitigation measures, until automation of conduct and impact mitigation in the in-city Day Ahead Market is achieved.

3. California Repercussions

In January 2002, the FERC created a new office, the Office of Market Oversight and Investigation (OMOI), tasked to oversee and assess the operations of the nation's gas, oil pipeline, and electricity markets. One of OMOI's functions is to further the Commission's understanding and oversight of energy markets across the nation.

In light of numerous revelations centered on the dysfunctional California energy markets of the past two years, there is increasing urgency to get OMOI staffed and functioning as quickly as possible. For instance, internal Enron memos detailing energy trading strategies the company engaged in to game the California energy markets prompted Commissioner William Massey to propose broad cooperation between the OMOI and regional market monitors in a May 15 meeting of the Commission.

> We need good, aggressive market monitoring. We have to stay ahead of the market participants. This will require teamwork between our now-forming Market Oversight Office, headed by Bill Hederman and the regional market monitors within the RTOs. That team must be given the resources and the authority to do their jobs in a thorough and professional manner that instills confidence in the marketplace.[127]

Additionally, Commissioner Massey called for upfront mitigation measures to prevent physical and economic withholding, refund protections for consumers, and "tough, meaningful sanctions on bad actors."[128]

C. New England Standard Market Design

In July 2002, the New England Power Pool (NEPOOL) and the ISO New England (ISO-NE) released their proposed "Market Rule 1,"[129] which is their proposal for standard market design rules for the New England electricity market. The Market Rule 1 was based on the PJM Interconnection, L.L.C. (PJM) market design and is consistant with the principles outlined in the Commission's Standard Market Design Working Paper.[130] The New England SMD will feature locational marginal pricing (LMP) scheme, which will initially employ a fully nodal approach for the supply side, with a zonal approach for the

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inherent in the manual application of the existing mitigation measures.

127. Commissioner William Massey, Remarks at the 791st Regular Meeting of the Federal Energy Regulatory Commission (May 15, 2002), *at* http://www.ferc.fed.us/calendar/commissionmeetings/transcripts/051502.pdf (last visited Mar. 20, 2003).

128. *Id.*

129. *New England Power Pool Market Rule 1*, ER02-2330 (F.E.R.C. docketed July 15, 2002).

130. *Working Paper*, *supra* note 103.

load side. The report states that ISO-NE software and hardware currently will not support full nodal pricing scheme for load, but that improvements are planned. The SMD will also operate both day-ahead and real-time Markets using LMP, with the Day-Ahead market being financially binding and entities that receive credit for ICAP will be required to participate on the day-ahead market. The real-time Market will include demand not scheduled day-ahead and will reflect real-time load, participant re-offers, hourly self-schedules, self-curtailments and general system conditions.

In addition to the PJM based market design, the installed capacity (ICAP) arrangements in the New England market are based substantially upon the NYISO ICAP market design. A main difference, and according to ISO-NE a major improvement over the PJM market design, is the use of 100% auctioned and duration FTRs. In the PJM system Firm Transmission Rights (FTRs) are allocated first in conjunction with firm transmission service, and then the residual FTRs are offered in an auction. NEPOOL and ISO-NE feel that their FTR proposal is an improvement over the PJM system, as it will allow FTRs to be acquired by those entities that value them most.

IV. FERC ORDERS REGARDING MARKET POWER IN RESTRUCTURED MARKETS

A. New York Independent System Operator

Between November 2001 and May 2002, the Commission issued several orders that both clarified the extent of the market mitigation rules to be applied by the NYISO and provided guidance for the development of market mitigation programs elsewhere. Two of these orders relate to bid cap limitations imposed by the NYISO after price spikes occurred in the operating reserves markets between late January and early March, 2000, shortly after the NYISO's startup.

In their November 2001 Order,[131] the FERC denied rehearing of its May 31, 2000 order.[132] The principal holdings of the May 2000 Order had been the FERC's approval of a bid cap of $2.52/MW for ten minute non-synchronized operating reserves (ten Minute NSR), addition of a requirement to also pay lost opportunity costs to successful bidders in the ten Minute NSR market, denial of (i) the NYISO's request to impose a comparable cap on spinning reserve bids, (ii) its request to implement an alternative dispute resolution (ADR) procedure to determine how to rebill for the period January 29-February 28, 2000 to mitigate the effect of the price spike, and (iii) its request to bill for the period March 1-28, 2000 to reflect the bid cap.

In the November 2001 Order, the Commission essentially reaffirmed all of the findings of the May 2000 Order.[133] In particular, it denied Niagara Mohawk Power Corporation and Rochester Gas & Electric Corporation's request for rehearing of the May 2000 Order, requesting operating reserve refunds for the period January 29 to March 28, 2000 because they alleged they had been

131. *New York Indep. Sys. Operator, Inc.*, 97 F.E.R.C. ¶ 61,155 (2001) [hereinafter November 2001 Order].

132. *New York Indep. Sys. Operator, Inc.*, 91 F.E.R.C. ¶ 61,218 (2000).

133. November 2001 Order, *supra* note 131, at 61,676.

unlawfully denied the opportunity to self-supply their own reserves under the NYISO OATT.[134] During this time, the NYISO required all load serving entities (LSEs) to purchase their operating reserve requirements from the NYISO-administered markets rather than supplying the requirements directly from generation that the LSEs controlled. The Commission determined that although it had found that the NYISO's requirement that purportedly self supplying LSEs must bid into and purchase reserves from the markets was not consistent with Order No. 888, it had not ruled the NYISO requirement inappropriate in the May 2000 Order.[135] Accordingly, it denied the request for refunds, but required the NYISO and market participants to attempt to develop a means to permit the provision of self-supply of operating reserves on a prospective basis.[136]

In upholding the $2.52/MW bid cap for the ten minute NSR market, the Commission rejected an attack on its original analysis finding that the operating reserve market was not sufficiently competitive.[137] It rejected an assertion that it should have adopted a "pivotal bidder analysis of competition" before making the finding of the lack of competitiveness and justifying the imposition of bid caps as untimely and insufficiently supported.[138] The Commission also denied a challenge that the $2.52/MW bid cap was unsupported by any quantitative analysis.[139] With respect to refunds for the period January 29 to March 28, 2000, the Commission refused to order refunds based on (i) its determination that section 206 of the Federal Power Act[140] prohibited the assessment of retroactive refunds and the Commission had not established a refund effective date applicable to the NYISO's markets and (ii) its general policy that market mitigation measures should be applied prospectively and that refunds cannot be reasonably determined for prices determined in a bid based market because customers cannot revisit their economic decisions.[141]

The Order also accepted the concept that operating reserves, *i.e.* spinning reserves, ten minute non-synchronized reserves, and thirty minute non-synchronized reserves, in order of decreasing price, and authorizing the NYISO to insure that the price of a "lower quality" operating reserve be no higher than the price of the "higher quality" reserve.[142]

Following the issuance of the November 2001 Order, the NYISO and several of the New York Transmission Owners separately filed appeals to the D.C. Circuit. Subsequently, however, the NYISO filed a second request for rehearing to the Commission. The D.C. Circuit subsequently dismissed the NYISO's appeal without prejudice under its long-standing doctrine preventing judicial review while the matter was still under consideration by the administrative agency. The appeals filed by the other transmission owners were

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134. *Id.*

135. November 2001 Order, *supra* note 131, at 61,676.

136. *Id.* at 61,677.

137. November 2001 Order, *supra* note 131, at 61,678.

138. November 2001 Order, *supra* note 131, at 61,155.

139. *Id.* at 61,679.

140. 16 U.S.C. § 824(e) (2000).

141. November 2001 Order, *supra* note 131, at 61,680.

142. *Id.*

consolidated but held in abeyance.

In its second rehearing request, the NYISO had argued that because the market monitoring program had been in place before January of 2000, and the March 27, 2000 filing to establish the $2.52/MW bid cap was made pursuant to section 205 of the FPA[143] as a change in rate, the Commission inappropriately relied on section 206 of the FPA[144] to find that it could not authorize the retroactive application of the mitigation measures for the January through March time period. NYISO argued that since the market monitoring plan had envisioned that the NYISO would make section 205 filings requesting authorizations to impose mitigation measures on a case-by-case basis and the tariff provided for rebilling, an establishment of separate refund effective dates would not be required.

On April 29, 2002, the Commission denied NYISO's second request for rehearing, but granted a request for rehearing filed by KeySpan-Ravenswood, Inc.[145] The Commission rejected this argument on the consistent precedent that an "existing just and reasonable rate may only be changed prospectively after certain events occur, all of which can occur no sooner than the date of the respective section 205 or 206 filing."[146] The Commission also rejected the argument that it had somehow made the NYISO's operating reserves rates subject to refund when it accepted the market monitoring plan. The Commission stated that it envisioned the market monitoring process to operate such that when NYISO identified a market flaw and made a section 205 filing, the flaw would be remedied prospectively.[147] The rehearing order also granted KeySpan's request to make ten minute NSR bidders eligible for payment of lost opportunity costs effective March 28, rather than May 31, 2000.[148]

In *New York Independent Operator System, Inc.*,[149] the Commission first approved an amendment to the NYISO's market mitigation plan that permitted the NYISO to implement an Automatic Bid Mitigation Procedure (AMP) in the NYISO's computerized process for establishing energy prices on an hourly basis in the day-ahead energy market for the summer of 2001. The AMP did not add any new tests for determining when mitigation was appropriate. In a follow-up order approving the extension of the AMP beyond the 2001 summer, the Commission directed NYISO to "file a comprehensive mitigation proposal"[150] addressing the AMP and how the NYISO's overall mitigation measures work in conjunction with the other mitigation measures already in effect or proposed for the NYISO, including the separately approved mitigation measures effective in Consolidated Edison's service area in New York City.[151] On March 20, 2002,

143. 16 U.S.C. § 824(d) (2000).

144. 16 U.S.C. § 824(e) (2000).

145. *New York Indep. Sys. Operator, Inc.*, 99 F.E.R.C. ¶ 61,125 (2002).

146. *Id.* at 61,534.

147. 99 F.E.R.C. ¶ 61,125, at 61,534.

148. *Id.* at 61,536.

149. *New York Indep. Sys. Operator, Inc.*, 95 F.E.R.C. ¶ 61,471 (2001).

150. Order Approving Extension of Automatic Mitigation Measures Subject to Conditions, 97 F.E.R.C. ¶ 61,242, 62,093 (2001).

151. *See generally id.*

the NYISO made a compliance filing, which restated and expanded upon its automated and comprehensive market mitigation measures.

C. AEP / Entergy / Southern Orders Concerning Market Power

In an order issued on November 20, 2001, the Commission ruled on three pending triennial market-power updates and announced that it would no longer use the hub-and-spoke methodology for assessing market power, but instead would apply the "Supply Margin Assessment" (SMA) screen.[152] The Commission stated that it intended on applying the SMA screen for an interim period, pending the outcome of a rulemaking proceeding that would be initiated at some point in the future.[153] The Commission went on to state, however, that it would not apply the SMA test to any applicant whose control-area market is part of an ISO or RTO with Commission-approved market monitoring and mitigation.[154]

In the SMA Order, the Commission stated that the new screen was designed to ascertain whether the applicant is a "pivotal supplier" in its home markets, *i.e.*, within the applicant's control area and in adjacent first-tier markets. Conceptually, the SMA screen asks whether the peak demand in the relevant destination market could be met if the applicant withheld all of its generation capacity in that market. The SMA screen attempts to answer this question by comparing the applicant's capacity and the uncommitted capacity in the supply areas directly interconnected to the applicant,[155] minus the load in the control area, which yields the "supply margin," with the applicant's total capacity in its control area. The Commission reasoned that if the supply margin is larger than the applicant's capacity, the applicant could not cause a shortage by withholding all of its capacity and thus would not be a pivotal, or must-run, supplier; *i.e.*, the applicant would pass the screen.[156]

The Commission determined that the three companies examined in the SMA Order did not pass the SMA screen.[157] For these utilities, the Commission required extensive mitigation intended to limit the applicants' alleged ability to exercise market power in the hourly spot markets in their respective control areas. Specifically, the Commission required each applicant to: (a) post its projected hourly incremental and decremental cost on a day-ahead basis; (b) make all of its uncommitted capacity available for day-ahead sales within their

152. Order on Triennial Market Power Updates and Announcing New, Interim Generation Market Power Screen and Mitigation Policy, *AEP Power Mktg., Inc.*, 97 F.E.R.C. ¶ 61,219 (2001) [hereinafter SMA Order]. The companies involved were AEP Power Marketing, Inc., AEP Service Corporation, CSW Power Marketing, Inc., CSW Energy Services, Inc., and Central and South West Services, Inc. (collectively AEP); Entergy Services, Inc.; and Southern Company Energy Marketing L.P.

153. In a June 28, 2002, "Message from the Chairman" posted on the Commission's website, the Commission indicated that it intended to convene a technical conference to address the SMA screen in the Fall of 2002, *available at* http://www.ferc.gov/webletter(final).htm (last visited Mar. 20, 2003).

154. SMA Order, *supra* note 152, at 61,970.

155. The SMA test recognizes limits on transmission import capability from neighboring supply areas, as well as load commitments that tie up generation in those areas.

156. SMA Order, *supra* note 152.

157. *Id.* at 61,971.

respective control areas at split-savings prices; and (c) purchase spot energy offered by sellers inside or outside the control areas at prices below the posted decremental costs. In addition, the Commission required the applicants to: (a) enable merchant generators seeking new interconnections to be studied as "network resources" without having formally been designated as such; (b) post on their web sites optimum areas on their systems for locating prospective generating facilities; and (c) relinquish to an independent third party administration of their OASIS sites.[158]

Several parties filed for rehearing of the SMA Order. On December 20, 2001, the Commission issued a notice delaying the effective date of that aspect of the mitigation designed to address hourly spot markets (but requiring the applicants to implement the remaining mitigation measures). On January 14, 2002, the Commission issued an Order Granting Rehearing for Further Consideration. Although the Commission has applied the SMA screen to numerous market-based rate applications and triennial update filings since it issued the SMA Order, as of the date of this article, the Commission has not addressed the merits of the arguments raised in the various petitions seeking rehearing of that order.

V. MERGERS AND CORPORATE REORGANIZATIONS

A. *American Electric Power, Inc.*

American Electric Power Company, Inc.[159] faced the need to accommodate state restructuring in Ohio and Texas, while maintaining existing system agreements and related arrangements among the operating companies providing retail electric service in the remaining nine states of the AEP system. Existing system agreements have permitted the integrated dispatch of the operating companies' generation and some sharing of generation capacity and of the benefits of centralized purchasing of energy and power from third parties in the two zones of the AEP system.[160] The agreements were based on the premise that the participants were vertically integrated public utilities providing retail electric service within defined service areas subject to state cost-of-service regulation. When Ohio and Texas deregulated generation, required corporate separation, and eliminated the concept of native load retail service in favor of competition,

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158. AEP already was in compliance with this requirement, pursuant to the Commission's order in *American Elec. Power Co. & Cent. & S.W. Corp.*, 90 F.E.R.C. ¶ 61,242 (2000); *aff'd sub nom.* Wabash Valley Power Ass'n, 268 F.3d 1105 (D.C. Cir. 2001).

159. The AEP system is the result of a merger between AEP and Central and South West Corporation (CSW), consummated on June 15, 2000. The D.C. Circuit affirmed the Commission order approving the merger in *Wabash Valley Power Ass'n, Inc. v. FERC*, 268 F.3d 1105 (2001). Later, the same court remanded the Securities and Exchange Commission order approving the merger under the Public Utility Holding Company Act, finding that the Commission had not satisfactorily explained its determination that the merger met the statutory requirement that the merged system be "physically interconnected or capable of physical interconnection," and had failed to adequately support its conclusion that the system would meet the requirement that it be "confined in its operations to a single area or region." *See also* National Rural Elec. Coop. Ass'n v. SEC, 276 F.3d 609 (2002) (quoting 15 U.S.C. § 79(a)(29)(A) (2002)).

160. The two zones are "AEP-East," consisting of the service territories of the pre-merger AEP operating companies, and "AEP-West," consisting of the service territories of the pre-merger CSW operating companies.

further participation in the system agreements by the AEP operating companies that provided retail electric service in those states became inappropriate.

In July 2001, American Electric Power Service Corporation, as agent for AEP, filed an application under section 203 of the Federal Power Act (FPA)[161] seeking approval for the transfer of jurisdictional facilities in order to separate generation and power marketing businesses from transmission and distribution businesses in Texas and Ohio. It also requested authority for the transfer of rights and obligations under certain power supply agreements.

AEP also filed initial and amended rate schedules, including amended system agreements for AEP-East and AEP-West, under FPA Section 205.[162] The amended agreements will permit the companies that are not restructuring to continue the coordination of their operations. The filings also included: an amended system-wide agreement; a unit power sales agreement that will assign to an AEP marketing affiliate that part of Southwest Electric Power Company's generating capacity that has been associated with its retail native load in Texas; unit power sales agreements by which most of the Ohio operating companies' generating capacity will be assigned to an AEP marketing affiliate; and generation facility agreements to handle situations where some of a facility's capacity will be committed to the competitive wholesale market, while the remainder will continue to be used by operating companies subject to state cost-of-service regulation.

Following interventions and protests, the FERC consolidated the dockets and directed the appointment of a settlement judge. In December 2001, AEP submitted a combined offer of settlement that reflected settlements with all of the state utility regulatory commissions or their staffs that had expressed concerns about AEP's filings. Several of the settlements also included government offices concerned with consumer well-being and organizations representing customers. AEP also submitted settlement agreements or otherwise noted resolution with most of its wholesale customers in the AEP-East area that actively participated in these proceedings, and with some of those in the AEP-West area. AEP also proposed to settle with some individual retail customers, and others withdrew their protests. To date, the Commission has not acted on the offer of settlement.

VI. TRANSMISSION RATES: RATE OF RETURN

During the past year, transmission owners began placing growing emphasis on rates of return and, specifically, return on equity allowed for transmission owners that have transferred operational control of transmission facilities to an ISO or RTO. In two leading cases, *Southern California Edison Co.*[163] and *System Energy Resources, Inc.*,[164] the Commission applied its traditional discounted cash flow methodology (DCF) to determine the proper return on equity for electrical transmission entities. The DCF is typically used to establish a zone of reasonableness, and the return for a particular transmission owner is set

161. 16 U.S.C. § 824(b) (2000).

162. *Id.*

163. *Southern Cal. Edison Co.*, 92 F.E.R.C. ¶ 61,070 (2000).

164. *System Energy Res., Inc.*, 96 F.E.R.C. ¶ 61,165 (2001).

within the zone by measuring the business and financial risks of the particular company against the risks of the proxy group that was used to establish the zone.[165]

The Commission's DCF formula was refined in *System Energy Resources, Inc.*, by requiring the use of "*all* of the available studies" to determine the proper industry proxy group for the DCF analysis.[166] Also, in *System Energy Resources, Inc.*, the Commission stressed that in determining the company's relative position with respect to the proxy group, all aspects of a company's risk need to be taken into account, rather than just bond or *Value Line* ratings.[167]

A major factor of contention over the past year has been whether transmission owners' entry into an ISO or an RTO presents additional risks that need to be quantified when determining return on equity allowances. In Order 2000-A,[168] the Commission stated that they would not presume that participation in an RTO does or does not increase the risk for transmission owners, stating that "[w]e have not prejudged the risk issue, and that issue will be determined case-by-case."[169] The Commission discussed the issue the *Southern California Edison* and in *System Energy Resources, Inc.*

In *Southern California Edison*, the Commission stated that the "financial data relied upon above is the best quantifiable measure of the investment community's current risk assessment."[170] In setting a return on equity for SoCal Edison, the Commission stated that "a substantial body of evidence has been presented in this case arguing for and against the relative riskiness of a utility transferring its transmission assets to an ISO,"[171] and went on to pronounce that "much of this evidence was disputed by one party or another, or was speculative" and "was tied only tangentially to SoCal Edison."[172] In this case, the FERC set a return on equity for SoCal Edison of 11.60%, which was above the mid-point of SoCal Edison's proxy group's return on equity.

The Commission also addressed the risk of entry into an RTO in *System Energy Resources, Inc.* In *System Energy*, the company argued to the FERC that it should receive a higher rate of return than SoCal Edison received because it is in a riskier operation than SoCal Edison. The Commission denied this request and established a return on equity of 10.8% and stated that "SoCal Edison faces

165. 92 F.E.R.C. ¶ 61,070, at 61,266. The specifics of the zone of reasonableness calculation were discussed in *Consumers Energy Co.*, 98 F.E.R.C. ¶ 61,333, at 62,416 (2002). The first step in the zone of reasonableness process is to determine the high and low monthly average dividend yields of the companies in the proxy group. From this data, the dividend yields are adjusted for the quarterly payments of dividends and the data are finally adjusted for the IBES-predicted growth rates of the proxy companies. The specific company in question is compared to the companies making up the zone of reasonableness to determine where to place the calculated allowed return on equity with respect to the zone of reasonableness.

166. 96 F.E.R.C. ¶ 61,165, at 61,733.

167. *Id.*

168. Order No. 2000-A, *Regional Transmission Orgs.*, [Regs. Preambles 1996-2000] F.E.R.C. STATS & REGS. ¶ 31,092 (2000).

169. *Id.* at 31,387.

170. *Southern Cal. Edison Co.*, 92 F.E.R.C. ¶ 61,070, 61,266 (2000).

171. *Id.*

172. 92 F.E.R.C. ¶ 61,070, at 61,266.

risks that SERI does not."[173] While the Commission stated that SoCal Edison had ceded control of their transmission assets to the CAISO, that fact was not determinative in the SoCal Edison risk analysis. The Commission emphasized that SoCal Edison's status as a full service electric utility, which is involved with generation, transmission, and distribution makes SoCal inherently more risky than SERI, which is a single nuclear generation unit with stable long-term purchase contracts.

Another recent return on equity issue is the Commission's willingness to boost an entity's return on equity if proposed within an "innovative" or "incentive" rate proposal. Order 2000[174] allows for rates that give entities an incentive to "achieve the goals of Regional Transmission Organizations, including efficient use of and investment in the transmission system and reliability benefits to consumers."[175] This innovative rate treatment, however, must be supported by a cost-benefit analysis and other studies, all requiring formal input. In its order in *Midwest Independent Transmission System Operator, Inc.*, the Commission ruled that a MISO proposal to increase the return on equity by an arbitrary 100 basis points was "an innovative rate proposal as defined in Order No. 2000," but did not authorize the increase because MISO did not adhere to the filing requirements set out in Order 2000, including the requirement that the proposal be supported by a cost-benefit analysis.[176] As of June 2002, the MISO had not filed with the Commission to obtain the 100 basis point incentive-based increase in its return on equity. Other aspects of the MISO's return on equity request are pending before the Commission, following an Initial Decision by Administrative Law Judge Cintron issued April 25, 2002, recommending a 12.38% return on equity.[177]

VII. SECTION 211 CASES

A. *City of College Station*

On November 8, 2001, the Commission issued an order on rehearing of its February 16, 1999 (Final Order)[178] in *City of College Station, Texas*.[179] The Commission issued its Final Order in light of the Texas Supreme Court's ruling that the Public Utility Commission of Texas (PUCT) lacked authority to "dictate by rule" the rates that municipally-owned utilities (such as the transmitting utilities in the College Station proceeding) must charge to other utilities for wholesale transmission service.[180] The dispute in this phase of the proceeding, which has been pending before the Commission since 1996, involved the rates

173. 96 F.E.R.C. ¶ 61,165, at 61,734.

174. Order No. 2000, *Regional Transmission Orgs.*, [Regs. Preambles 1996-2000] F.E.R.C. STATS & REGS. ¶ 31,089 (1999).

175. 18 C.F.R. § 35.34 (2002).

176. *Midwest Indep. Transmission Sys. Operator, Inc.*, 97 F.E.R.C. ¶ 61,033, 61,174-75 (2001).

177. *Midwest Indep. Transmission Sys. Operator, Inc.*, 99 F.E.R.C. ¶ 63,011 (2002).

178. *City of College Station, Tex.*, 86 F.E.R.C. ¶ 61,165 (1995).

179. *City of College Station, Tex.*, 97 F.E.R.C. ¶ 61,152 (2001).

180. *Id.* at 61,665.

for transmission service in the Electric Reliability Council of Texas (ERCOT) during the locked-in period of January 1, 1997 to December 31, 1999. Because the PUCT lacked authority to determine the rates during that period, the Commission established settlement judge procedures and directed the parties to attempt to reach a "mutually agreeable resolution" of their dispute over the appropriate rates for that period.[181] For the Section 211 of the FPA[182] transmission service provided thereafter, the PUCT-established, ERCOT-wide rates for transmission service would apply. The Commission declined to postpone the proceeding any longer to wait for further action by the PUCT and Texas Supreme Court.[183]

The Commission also upheld its decision in the Final Order that it lacked authority to set the rates for service before the issuance of its Final Order. The Commission explained that its order directing transmission service was conditioned on the transmission providers being "fully and appropriately compensated," and indicated that the PUCT (or other "appropriate state authority") would set the rates for transmission service provided before the Final Order.[184] Finally, the Commission upheld its decision in the Final Order to allow the transmission providers to seek recovery of their regulatory expenses in this proceeding, but required them to make an appropriate filing in order to recover the expenses.[185]

In a subsequent order,[186] the Commission again upheld its determination that it cannot set the rates for service before its Final Order. The Commission explained that:

> [s]o long as the [PUCT] prescribes rates for the transmission services that [the transmission providers] provided prior to the date of our final order, our public interest finding is satisfied. As to the adequacy of any rates that the [PUCT] prescribes, [the transmission providers'] remedy must be in the Texas courts. It cannot be at this Commission.[187]

The Commission denied subsequent requests for rehearing of this issue.[188]

B. Suffolk County Electrical Agency

On September 27, 2001, the Commission issued an order in *Suffolk County Electrical Agency*[189] (SCEA), that renewed the long dormant proceedings to determine terms and conditions for a wheeling service to be provided to, what is now, the Long Island Power Authority's (LIPA) operating subsidiary to SCEA. This case had arisen in 1996 with the filing of SCEA's application for transmission service from the Long Island Lighting Company (LILCO) pursuant

181. 97 F.E.R.C. ¶ 61,152, at 61,665-66.

182. 16 U.S.C. § 824(j) (2000).

183. 97 F.E.R.C. ¶ 61,152, at 61,665.

184. *Id.* at 61,666.

185. *City of College Station, Tex.*, 97 F.E.R.C. ¶ 61,152, 61,667-68.

186. *City of College Station, Tex.*, 98 F.E.R.C. ¶ 61,222 (Feb. 28, 2002).

187. *Id.* at 61,877.

188. *City of College Station, Tex.*, 99 F.E.R.C. ¶ 61,163 (2002).

189. *Suffolk County Elec. Agency*, 96 F.E.R.C. ¶ 61,349 (2001).

to Sections 211 and 212 of the FPA[190] to provide service to residential retail ratepayers in Suffolk County, New York. The Commission issued an order on December 31, 1996 directing LILCO to provide SCEA transmission service over its system.[191] This order was followed by negotiations where the parties failed to reach a consensus on issues regarding the cost of transmission service, which necessitated a series of procedural motions to defer the procedural deadlines for the submission of briefs. Between mid-1997 and 2001, the Commission took no action in the case. In 1998, the LIPA purchased LILCO and thereafter implemented a retail access program that covered the service area, including Suffolk County.

The September 27, 2001 order set for hearing the rates, terms, and conditions for the requested transmission service, as well as the disputes surrounding implementation studies, back-up power, and charges for billing services.[192] The hearing was held in abeyance to give the parties an opportunity to negotiate these issues.

The order further clarified the specific meaning behind the ban on retail wheeling in Section 212(h) of the FPA.[193] Section 212(h) was a paramount issue in the briefs submitted by both parties because SCEA's ability to qualify for a Section 211 order directing transmission service could be precluded if the Commission determined that its request resulted in retail wheeling. The FERC explained that the language in 212(h) prohibited the Commission from issuing a transmission order that mandated retail wheeling directly to an ultimate consumer, unless the entity selling the electric energy at retail is in the enumerated list and either the seller was providing service to that customer on October 24, 1992, or the seller would utilize transmission or distribution facilities that it owns or controls to deliver all the electric energy.[194] The Commission found that since SCEA arguably served retail customers on October 24, 1992 under a program created by New York State, Suffolk could obtain energy to serve its grandfathered retail customers.[195]

The settlement judge submitted a final report on March 22, 2002, informing the Chief Judge that there was a low probability of settlement due to the "staleness of the record and the materially changed circumstances of the parties since the 1996 proceedings."[196] The case was then set for hearing.

C. Pinnacle West Capital Corporation

In *Pinnacle West Capital Corporation*,[197] the Commission granted a utility's request for continued transmission service over a public power district's transmission system when the utility's existing lease of the system expired. In

190. 16 U.S.C. §§ 824(j), 824(k), (h) (2000).

191. *Suffolk County Elec. Agency*, 77 F.E.R.C. ¶ 61,355 (1996).

192. *Suffolk County Elec. Agency*, 96 F.E.R.C. ¶ 61,349, 62,302.

193. *Id.* at 63,301.

194. 96 F.E.R.C. ¶ 61,349, at 63,301.

195. *Id.*

196. *Suffolk County Elec. Agency*, No. TX96-4-000, slip op. at 1 (2002).

197. *Pinnacle West Capital Corp.*, 98 F.E.R.C. ¶ 61,039 (2002).

accordance with Commission precedent, the Commission limited the utility's Section 211 application to the service that it had requested in its "good faith" request for transmission service (essentially, continuation of the same service under the lease), as the application may not "differ materially from the good-faith request."[198] In addition, the Commission explained that the district's voluntary continuation of transmission service to the utility could not prevent the Commission from exercising its authority to resolve issues of rates, terms, and conditions of such service.[199] Finally, the Commission conditioned its "public interest" finding upon the district being "fully and fairly compensated" for the transmission service it provided from the date voluntary service began to the date of the Commission's final order.[200] As in *College Station*, the Commission explained that it did not have authority to set the rates of service provided before its final order, but the public-interest standard requires that the transmission provider be fully compensated.[201]

D. *Missouri Basin Municipal Power Agency*

On April 12, 2002, the Commission denied the 1997 request by Missouri Basin Municipal Power Agency (Missouri Basin) for transmission service on the facilities of the Western Area Power Administration (WAPA), affirming the 1998 Initial Decision[202] that had found that such service could not be provided without unreasonably impairing the continued reliability of affected electric systems.[203] Missouri Basin had submitted its Section 211 transmission service request in anticipation of the expiration of an existing pooling agreement, in which WAPA provided service over the Joint Transmission System (JTS) comprising the transmission facilities of WAPA, Missouri Basin, Basin Electric Power Cooperative (Basin Electric) and Heartland Consumers Power District (Heartland). Missouri Basin's Section 211 request sought service over only those facilities owned by WAPA. WAPA declined the request, and instead offered service over the "Integrated System" established by WAPA, Basin Electric and Heartland to replace the expired JTS pooling arrangement. The Commission set for hearing the issue of whether WAPA could provide the requested service without unreasonably impairing the continued reliability of the affected electric systems. The Initial Decision found that it could not because the facilities comprising the Integrated System had been jointly planned and operated and was, in fact, an integrated system.[204]

The Commission summarily affirmed the Initial Decision's findings and, accordingly, denied Missouri Basin's Section 211 request because the requested service could not be provided without impairing the reliability of affected

198. *Id.* at 61,114.

199. 98 F.E.R.C. ¶ 61,039, at 61,114.

200. *Id.* at 61,115.

201. 98 F.E.R.C. ¶ 61,039, at 61,115 n.12.

202. *Missouri Basin Mun. Power Agency*, 82 F.E.R.C. ¶ 63,015 (1998) (hereinafter Initial Decision).

203. *Missouri Basin Mun. Power Agency*, 99 F.E.R.C. ¶ 61,062 (2002).

204. Initial Decision, *supra* note 202, at 65,118-20.

systems.[205] The Commission declined to order the expansion of WAPA's facilities to accommodate Missouri Basin's request because the existing Integrated System could accommodate the requested service. The Commission noted that "[n]owhere in Section 211 is the applicant permitted to select any *particular* transmission facilities that the transmitting utility owns, operates or controls from which to receive the requested transmission service."[206] The Commission also found that the open access transmission tariff submitted by WAPA for the Integrated System satisfied the Commission's comparability (non-discrimination) standards and was therefore an acceptable "reciprocity" tariff.[207]

E. *Public Service Company of Colorado*

The Commission denied a request by a utility for transmission service over the facilities of several transmitting utilities because (i) the utility had reached a settlement with one of the transmitting utilities and therefore had no further claims against it, and (ii) the other transmitting utilities had acceptable reciprocity tariffs on file with the Commission and the requesting utility had made no attempt to show why service under those tariffs was not sufficient.[208]

VIII. STANDARDS OF CONDUCT

On September 27, 2001, the Commission proposed to adopt one set of Standards of Conduct (Standards) to govern the relationships between regulated transmission providers and all their energy affiliates, not just those engaged in marketing or sales functions. The Notice of Proposed Rulemaking (NOPR)[209] would apply uniformly to natural gas pipelines and transmission providers that are currently subject to the gas Standards in Part 161 of the FERC's regulations[210] and the electric Standards in Part 37 of the FERC's regulations.[211] The new Standards would be codified in a new Subchapter S, and Parts 37 and 161 of the current Standards would be deleted. The FERC noted that electric transmission providers that do not operate or control transmission facilities and participate in a FERC-approved RTO could be exempt from the proposed Standards. The Commission cautioned that depending on how the RTO is structured, there might be a continued need to apply the proposed Standards to

205. 99 F.E.R.C. ¶ 61,062 at 61,295.

206. *Id.*

207. 99 F.E.R.C. ¶ 61,062, at 61,299. The Commission also noted that, in light of its acceptance of WAPA's reciprocity tariff, Missouri Basin would have the burden of proof to show why service under that tariff is not sufficient and why a Section 211 order would be required instead. *Id.* at 61,295 n.22.

208. *Pub. Serv. Co. of Colo.*, 99 F.E.R.C. ¶ 61,214 (2002). The Commission also dismissed the Section 211 request against another entity that owned and controlled no transmission facilities and therefore was not a "transmitting utility" to which a Section 211 request could be made. *Id.*, slip op. at 6-7.

209. Notice of Proposed Rulemaking, *Standards of Conduct for Transmission Providers*, IV F.E.R.C. STATS. & REGS. ¶ 32,555 (2001), 96 F.E.R.C. ¶ 61,334 (2001) [hereinafter Standards NOPR].

210. Final Rulemaking, *Standards of Conduct for Interstate Pipelines with Mktg. Affiliates*, II F.E.R.C. STATS. & REGS. ¶¶ 19,860-863 (2000) (to be codified at 18 C.F.R. pt. 161).

211. *Open Access Same-Time Info. Sys. and Standards of Conduct*, I F.E.R.C. STATS. & REGS. ¶¶ 14,100-108 (1998) (to be codified at 18 C.F.R. ¶¶ 37.1-37.8).

transmission providers that are members of an RTO.[212]

The FERC stated that the proposed Standards would "combine, revise and conform the current gas and electric standards."[213] Currently, the Standards restrict the ability of interstate natural gas pipelines and electric utilities (transmission providers) to give their marketing affiliates or wholesale merchant functions undue preferences over non-affiliated transportation customers, yet they fail to address the sharing of confidential shipper information and transportation information with all energy affiliates. The FERC is also concerned that a transmission provider's market power could be transferred to its affiliated businesses because the existing rules do not cover all affiliate relationships; conversely, a transmission provider's market power could also be increased by virtue of the affiliate's business.

The FERC proposes to define a transmission provider as any public utility that owns, operates, or controls interstate transmission facilities or any natural gas pipeline company subject to the current Standards.[214] Under the proposal, an energy affiliate is defined as any entity affiliated with a transmission provider (gas or electric) that engages in or is involved in transmission transactions or manages or controls transmission capacity or buys, sells, trades, or administers natural gas or electric energy or engages in financial transactions relating to the sale or transmission of natural gas or electric energy.[215] Under this definition, for example, a transmission provider would be required to treat affiliated asset managers as energy affiliates.

Most notably, the proposed Standards would require a separation of the transmission function from all sales functions, including bundled retail sales, and a restriction on preferential access to transmission information for the bundled retail sales function.[216] Therefore, the transmission providers' employees engaged in transmission system operation would function independently from the providers' sales or marketing employees and energy affiliates. However, in the event of emergencies affecting system reliability, employees may take whatever steps are necessary to keep the transmission systems in operation, including, if necessary, using affiliates' employees.[217]

The NOPR also included several proposed requirements for posting information on the companies' websites such as employee transfers and corporate structures.[218] Finally, the FERC asked for comments on a variety of issues not directly related to the Standards which included: (1) the codification of the electric codes of conduct that guard against discrimination by power marketers or other affiliates that request market-based rate authority; (2) additional measures that may be necessary to limit transmission providers' abilities to grant their affiliates undue preferences; and (3) whether discount

212. Standards NOPR, *supra* note 209, at 34,083.

213. *Id.*

214. Standards NOPR, *supra* note 209, at 34,083.

215. *Id.* at 34,084–85.

216. Standards NOPR, *supra* note 209, at 34,083-85.

217. *Id.* at 34,085.

218. Standards NOPR, *supra* note 209, at 34,085.

bidding by marketing affiliates affects the gas market. Initial comments were due on December 20, 2001.

In the meantime, in *Dominion Resources v. FERC*, the U.S. Court of Appeals for the District of Columbia, on April 19, 2002,[219] vacated a FERC May 2000 Compliance Order[220] regarding Codes of Conduct (Codes) that were to apply to Dominion Resources, Inc. (Dominion) following its merger with Consolidated Natural Gas Company. The Codes are the merger companies' gas pipeline Standards of Conduct. Dominion argued that the FERC's interpretation of the scope of the Codes contained in the Compliance Order was much broader than what Dominion had agreed to in the Merger Order.[221] Dominion believed that it agreed to the Codes being applied to only those affiliates in the corporate family who engage in the wholesale electric merchant function, but the FERC applied the Codes to the entire corporate family. The Court found that the FERC's interpretation was a "sharp and unexplained" break with precedent and therefore arbitrary and capricious.[222] However, it was also noted that the FERC can make its case for a broader interpretation in its current rulemaking.[223]

On April 25, 2002, in response to the NOPR comments filed by the industry, the FERC released a staff paper that analyzed the issues raised in the comments received and announced a technical conference to be held at FERC on May 21, 2002.[224] In the Staff paper, the staff noted that further analysis is necessary to evaluate the implications of the D.C. Circuit's recent decision in *Dominion Resources v. FERC*, that the industry is generally supportive of one set of Standards of Conduct for both the electric and gas industries and that few commentors supported any of the additional policy suggestions set forth in the NOPR. The Staff paper also introduced the concept of applying the automatic imputation rule, which currently is used in the natural gas industry, to the electric industry. The following discussion summarizes the electric and gas issues raised in the Staff paper.

Definition of Energy Affilitate: Commentors urged a narrowing of the definition of energy affiliate to only include those affiliates that are involved in transportation on affiliate transmission providers' systems. Several commentors also asked for a narrowing of the definition of energy affiliate to exclude entities that engage in financial transactions. Staff disagreed with both proposals and stated that the transmission market and commodity market are so intertwined that it is possible to operate the transmission system in a manner to assist affiliate.[225]

Commentors argued that the definition of energy affiliate could be

219. *Dominion Resources, Inc. & Consolidated Natural Gas Co.*, 89 F.E.R.C. ¶ 61,162 (1999), *order on compliance filing*, 91 F.E.R.C. ¶ 61,140 (2000), *order denying reh'g*, 93 F.E.R.C. ¶ 61,214 (2000), *vacated and remanded*, Dominion Resources, Inc. v. F.E.R.C., 286 F.3d 586 (D.C. Cir. 2002).

220. *Dominion Resources, Inc. & Consolidated Natural Gas Co.*, 91 F.E.R.C. ¶ 61,140 (2000).

221. *Dominion Resources, Inc. & Consolidated Natural Gas Co.*, 89 F.E.R.C. ¶ 61,162 (1999).

222. Dominion Resources, Inc. v. FERC, 286 F.3d 586, 592 (D.C. Cir. 2002).

223. *Id.* at 593.

224. Notice of Staff Conference, *Standards of Conduct for Transmission Providers*, No. RM-1010-00 (F.E.R.C. docketed Apr. 25, 2002) [hereinafter Staff Analysis].

225. *Id.* at 6.

interpreted to include holding or service companies, which could limit the ability of senior officers and directors to perform their corporate responsibilities. Staff recognized the problem and stated that, because holding and service companies are not typically participants in the energy or transmission markets, the rule will include a non-conduit rule for employees in holding companies or service companies.[226]

Responding to Commentors' arguments that even if an energy affiliate was just buying power for its own operations, such as for lights and heat, they would be subject to the reporting and posting requirements of the rule, Staff agreed to clarify the definition to exclude any affiliate of a transmission provider that is solely purchasing power or natural gas for its own consumption and is not using an affiliated transmission provider for transmission.[227]

Finally, after reviewing comments, Staff agreed to various exclusions to the definition of energy affiliate, including affiliated transmission providers and foreign affiliates that do not participate in US energy markets.[228]

Bundled Retail Load: Fourteen Commentors said the FERC has the ability to extend the Standards to bundled retail loads while thirty-six Commentors argued that FERC is overstepping its jurisdictional bounds by attempting to regulate the employees, which are regulated by the states. In Order 888,[229] the FERC previously provided an exemption that permitted electric transmission providers to use the same employees for their interstate transmission business and their bundled retail sales and distribution businesses. The Staff stated that the NOPR's proposal is consistent with the Commission's jurisdiction as set forth in the Supreme Court's decision regarding Order 888.[230] Instead, Staff stated that the question is one of costs versus benefits when addressing potential anticompetitive effects by the elimination of the native load preference and it solicited industry comments regarding the cost of this proposal.[231]

The Independent Functioning Requirement: The NOPR would require the transmission business to function independently from any energy affiliates (not just the marketing and wholesale functions). Commentors were almost unanimous in dissent, pointing to the costs of compliance and the number of shared non-transmission function employees they have. Staff stated that by more narrowly defining the definition of "energy affiliate", as discussed above, the cost of compliance would be reduced and, therefore, the Staff recommended that the FERC continue to permit the sharing of non-transmission functions between the transmission business and its energy affiliates.[232]

Information Disclosure Requirements / Prohibitions: Many commentors

226. Staff Analysis, *supra* note 224, at 7-8.

227. *Id.* at 8.

228. Staff Analysis, *supra* note 224, at 8.

229. Order No. 888, *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities and Recovery of Stranded Costs by Public Utilities*, [Regs. Preambles 1991 -1996] F.E.R.C. STATS. & REGS. ¶ 31,036 (1996).

230. New York v. FERC, 122 S.Ct. 1012 (March 5, 2002).

231. Staff Analysis, *supra* note 224, at 14-15.

232. *Id.* at 18.

supported the codification of the current electricity no-conduit rule. Under this rule a shared, non-operating employee could receive transmission information as long as he or she did not act as a conduit for sharing the information with the marketing affiliate or wholesale merchant function. Staff, however, recommended the automatic imputation rule for shared non-operating employees that regularly receive transmission information.[233] According to the automatic imputation rule, once an employee who performs functions for both the transmission business and its marketing affiliate receives transmission information, the information is automatically imputed to the marketing affiliate. However, Staff added that employees could share crucial information necessary for reliability and that rules could be promulgated that govern what can be shared.[234]

Posting Organizational Charts and Job Descriptions: Under the NOPR, (1) the transmission provider would have to identify all of its energy affiliates on its organizational charts in order to provide a clear picture of the transmission provider's relative position in the corporate structure of the parent company; and (2) a transmission provider would have to provide additional information concerning any employees it shares with its energy affiliates.[235] Staff did not agree with commentors concerns regarding the volume of information to be posted and the impracticality that every change can be posted within three days. A technical conference was held at the FERC on May 21, 2002 in which the above topics were discussed with the FERC Staff. Chairman Wood and Commissioner Breathitt were both in attendance for much of the day. The next round of comments related to the Staff paper and technical conference were due on June 14, 2002.

CONCLUSION

The past year saw the Commission take dramatic steps in the formation of RTOs in various portions on the U.S. electricity market. The Commission approved the Midwest ISO as the first fully functional RTO, and rejected the Alliance Companies in their bid for RTO status. At the year's close, the Commission was set to release their proposed Standard Market Design rulemaking, which is certain to dramatically affect the operations of the American electricity industry. Also, the coming year is likely to bring resolution to the controversial proposed Standards of Conduct for the electric and natural gas industries that was described above.

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233. *Staff Analysis*, *supra* note 224, at 21.

234. *Id.* at 22.

235. *Standards NOPR*, *supra* note 209, at 34,085.

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