REPORT OF THE COMMITTEE ON ELECTRIC UTILITY REGULATION

I. RESTRUCTURING

A. *Federal Energy Regulatory Commission*

1. Open Access Transmission Service

The Federal Energy Regulatory Commission (FERC) in 1997 upheld its landmark final rule on open access transmission service and stranded costs, Order No. 888.[1] The FERC's Open Access Rule requires each "public utility" that owns, operates or controls interstate electric transmission facilities to (i) provide transmission service to its customers on a basis comparable to that which it provides transmission service for itself on behalf of its own customers, (ii) offer generation, transmission and ancillary services on an unbundled, separately-priced basis, and (iii) separate its marketing and transmission functions. The *pro-forma* open access transmission tariff, which sets forth the standard terms and conditions under which public utilities must of-

1. Order No. 888, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Service by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, F.E.R.C. STATS. & REGS. ¶ 31,036, 61 Fed. Reg. 21,540 (1996) (codified at 18 C.F.R. pts. 35, 385) [hereinafter Order No. 888], *clarified*, 76 F.E.R.C. ¶ 61,009 and 76 F.E.R.C. ¶ 61,347 (1996), *order on reh'g*, Order No. 888-A, III F.E.R.C. STATS. & REGS. ¶ 31,048, 62 Fed. Reg. 12,274 (codified at 18 C.F.R. pt. 35 (1997) [hereinafter Order No. 888-A], *order on reh'g*, Order No. 888-B, 81 F.E.R.C. ¶ 61,248, 62 Fed. Reg. 64,688 (1997) [hereinafter Order No. 888-B], *order on reh'g*, Order No. 888-C, 82 F.E.R.C. ¶ 61,046, 62 Fed. Reg. 64,688 (1998) [hereinafter Order No. 888-C]. Hereinafter, Order Nos. 888, 888-A, 888-B, and 888-C are referred to collectively as the Open Access Rule.

fer open access transmission service, implements the principle of comparability of service. As indicated by the FERC, "unbundled electric transmission service will be the centerpiece of a freely traded commodity market in electricity in which wholesale customers can shop for competitively-priced power."[2]

a. Order No. 888-A

In Order No. 888-A, the FERC generally reaffirmed and clarified the principal provisions of Order No. 888.

i. Contract Reform

Order No. 888 provides that utilities can modify existing contracts to seek recovery of "stranded costs," or costs that cannot be recovered (*i.e.*, that become "stranded") when a customer uses the open access transmission tariff to purchase power supplies elsewhere. In Order No. 888-A, the FERC clarified that as a balance to utilities' rights to modify their contracts, customers would be allowed to seek to amend their *Mobile-Sierra* contracts to modify *any* contract term or to terminate the contract, without having to show that the contract is contrary to the public interest (the *Mobile-Sierra* standard). Such customers would have to show that the contract provisions are no longer just and reasonable.

ii. Comparability

The FERC modified the definition of "eligible customer" under the *pro-forma* tariff to clarify that, with respect to service that it is prohibited from ordering under section 212(h) of the Federal Power Act[3] (FPA) (*i.e.*, direct retail wheeling and "sham" wholesale wheeling), otherwise eligible entities may obtain service under the tariff only if it is pursuant to a state requirement or if offered voluntarily by the transmission provider.[4] The FERC also clarified that if a transmission provider supplies direct unbundled retail transmission service (whether pursuant to a state requirement or by voluntary offer), it must do so under the open access tariff.[5]

The FERC clarified that it has the authority to order indirect unbundled retail transmission services, reaffirming its conclusion that it has jurisdiction over the rates, terms and conditions of unbundled transmission service provided to retail customers.[6] Finally, the FERC clarified that transmission providers do not have to take service under the open access tariff for the transmission of power purchased on behalf of their bundled retail customers.[7] The FERC concluded that it does not have jurisdiction over such bundled retail

2. Order No. 888-A, at 30,176.
3. 16 U.S.C. § 824k (1997).
4. Order No. 888-A, at 30,214.
5. Order No. 888-A, at 30,214.
6. Order No. 888-A, at 30,214.
7. Order No. 888-A, at 30,216.

sales.[8]

iii. Ancillary Services

The FERC clarified that a transmission provider's sale of ancillary services associated with providing basic transmission service is not a wholesale merchant function and thus does not violate the standards of conduct requiring the separation of transmission and merchant functions.[9]

iv. *Pro-Forma* Tariff Provisions

The FERC clarified that a network customer may not take transmission service for only a portion of its load. It suggested several alternatives (short of a section 206 complaint) for the customer to pursue to avoid double payments where a network customer also had a bundled power purchase contract.[10] The FERC also made clear that the firm point-to-point transmission rate represents a maximum rate or cap for non-firm point-to-point transmission rates, and emphasized that in order to reflect the inferior, interruptible nature of non-firm service and promote efficient use of the transmission system (*i.e.*, encourage throughput), non-firm service was expected to be priced below the price cap.[11] Finally, the FERC reiterated its policy enunciated in *Arizona Public Service Company*[12] that in-kind transactions must be provided on a non-discriminatory basis and be unbundled, and that associated transmission must be obtained under the open access transmission tariff.[13]

The FERC modified the language of the force majeure provision to clarify that acts of negligence or intentional wrongdoing were not covered.[14] The FERC declined to impose an indemnification obligation on the transmission provider like that imposed on the customer for third-party claims arising from the transmission provider's performance of its obligations under the tariff, and also declined to extend the indemnification obligation so that it would apply even in cases where the transmission provider had been negligent.[15]

8. Order No. 888-A, at 30,216, 30,226.

9. Order No. 888-A, at 30,236.

10. Using network service, for example, the customer could designate its existing generation supply contract(s) as a network resource and the associated load served under such contract(s) designated as network load; the customer could then (i) negotiate with the transmission provider to obtain a credit on its network service bill for any separate transmission arrangements or for the unbundled transmission rate component of the existing generation supply contract, or (ii) seek to have any separate transmission or the unbundled transmission rate component of its generation supply contract eliminated in recognition of the network transmission service being provided and paid for under the tariff. Using point-to-point service, the customer could identify the discrete points of delivery being served under existing generation supply and existing transmission contracts and acquire additional point-to-point transmission service under the tariff for any remaining load at those discrete points of delivery. Order No. 888-A, at 30,261.

11. Order No. 888-A, at 30,272.

12. *Arizona Pub. Service Co.*, 78 F.E.R.C. ¶ 61,016 (1997).

13. Order No. 888-A, at 30,276.

14. *See* Section 10.1 of the *pro-forma* tariff.

15. Order No. 888-A, at 30,301.

The FERC extended the "umbrella" service agreement approach to short-term firm transactions. Thus, a transmission provider need only submit an umbrella service agreement (*i.e.*, an agreement of general applicability) to cover short-term firm transactions with a particular customer.[16]

The FERC also made a variety of clarifications with respect to the *pro-forma* tariff. For example, in addition to changes to reflect the clarifications and modifications discussed elsewhere in this report, the FERC:

- Modified Sections 13.2 and 14.2 of the *pro-forma* tariff to establish specific time frames within which a customer must respond to a longer-term competing request for transmission service.[17]
- Clarified that the requirement to curtail service proportionally to all customers extends only to those transactions (whether firm or non-firm) that alleviate the constraint, and that such curtailments must be made on a non-discriminatory basis, including the transmission provider's own wholesale uses of the system.[18]
- Clarified that the ability to reserve capacity to meet the reliability needs of a transmission provider's native load applies equally to present transmission facilities and transmission facilities that are built in the future.
- Modified Schedule 2 of the *pro-forma* tariff to allow a transmission customer to supply at least part of the reactive power service it requires.[19]
- Clarified that Energy Imbalance Service supplies energy for mismatches between scheduled deliveries and actual loads but does not apply to mismatches between energy scheduled and energy generated.[20]
- Raised the "dead band" as to which the Energy Imbalance Service charges apply from the lesser of 1.5% or 1 MW to the lesser of 1.5% or 2 MW. The FERC also clarified that a transmitting utility and a customer could negotiate a different bandwidth.[21]
- Clarified that its transmission discounting policy applies to the discounting of ancillary service charges.[22]
- Modified the *pro-forma* tariff to allow a customer to designate as a network resource a *leased* generating resource (not just *owned* or *purchased* resources).[23]

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16. Order No. 888-A, at 30,302-30,303. The FERC also made several minor modifications to the service agreement forms attached to the tariff to facilitate the umbrella approach. Order No. 888-A, at 30,303.

17. Order No. 888-A, at 30,316.

18. Order No. 888-A, at 30,279.

19. Order No. 888-A, at 30,228. The FERC also modified Schedule 2 to refer to generating facilities that are under the control of the control area operator, instead of in the control area, since the control area operator must be able to control the dispatch of reactive power from the generating facilities. Order No. 888-A, at 30,228.

20. Order No. 888-A, at 30,230.

21. Order No. 888-A, at 30,232-30,233.

22. Order No. 888-A, at 30,237.

23. Order No. 888-A, at 30,312.

v. Discount Policies

The FERC modified its discounting requirements in three significant ways: (i) all offers of and requests for discounts of transmission and ancillary services must be posted on the transmission provider's Open Access Same-time Information System (OASIS); (ii) once the transmission provider and customer agree on a discount, the details of the discounted service (price, points of receipt and delivery, and length of service) must be posted immediately on the OASIS; and (iii) when a discount is offered over one path, the transmission provider must also provide the discount only over unconstrained paths that go to the same point(s) of delivery as the discounted service being provided on the transmission provider's system.[24] This narrowed the policy established by Order No. 888, which provided that the discount had to be offered over *all* unconstrained paths on the provider's system. The FERC also clarified that a transmission provider may limit its offers of discounts over the OASIS to particular time periods.

vi. Reciprocity

The FERC upheld the reciprocity requirement that a customer receiving transmission service under the pro-forma tariff must, as a condition of receiving that service, agree to provide reciprocal (or comparable) service to the transmission provider,[25] but clarified the requirement in a number of respects, including the following:

- A public utility may waive the reciprocity condition by offering transmission service to a non-public utility without requiring reciprocal service in return, but must still provide transmission service through the *pro-forma* tariff.[26]
- A non-public utility cannot avoid its responsibilities by obtaining transmission service through other customers; and the seller as well as the buyer in the chain of a transaction involving a non-public utility will have to comply with the reciprocity condition.[27]
- A non-public utility may satisfy the reciprocity obligation through a bilateral agreement with the transmission provider, rather than an open access tariff of general applicability.[28]
- The FERC clarified that the reciprocity provision applies even to those utilities that do not own or control *interstate* transmission facilities, *i.e.*, foreign utilities and those utilities located in the insular Electric Reliability Council of Texas region.

24. Order No. 888-A, at 30,274.

25. Order No. 888-A, at 30,285.

26. Order No. 888-A, at 30,285-30,286. In contrast to its position in Order No. 888, the FERC held in Order No. 888-A that bilateral contracts for transmission service provided by a public utility are not permitted.

27. Order No. 888-A, at 30,287. Section 6 of the *pro-forma* tariff was modified accordingly.

28. Order No. 888-A, at 30,289.

- The FERC also made a number of clarifications to its policies with respect to private activity and local furnishing bonds.

The FERC later clarified the reciprocity condition as it applies to Canadian sales of electric power to United States utilities at the U.S.-Canada border. In response to a Canadian utility's motion to stay the effectiveness of the reciprocity condition to Canadian utilities, the FERC clarified that the reciprocity condition of the *pro-forma* tariff does not impose the reciprocity condition in circumstances where a Canadian utility sells power to a U.S. utility located at the U.S.-Canada border, title to the electric power transfers to the U.S. border utility, and the power is then sold to a U.S. customer that has no affiliation with, and no contractual or other tie to, the Canadian utility.[29]

b. Order No. 888-B

In Order No. 888-B, the FERC affirmed, with certain clarifications, the "fundamental calls" made in Order No. 888-A.[30] In particular, the FERC made the following modifications or clarifications:

- Clarified that a public utility should provide transmission service only under the *pro-forma* tariff (except in "unusual circumstances"), but that a non-public utility customer providing service pursuant to the reciprocity condition may provide such service under a bilateral agreement.[31]
- Clarified that an existing transmission customer exercising its right of first refusal will be required to match the term of service requested by another potential customer and may be required to pay the transmission provider's maximum filed transmission rate (for substantially similar service of equal or greater duration).[32]
- Clarified that transmission associated with a single, indivisible power purchase made on behalf of both wholesale and retail native load must be obtained under the open access tariff for the entire transaction.[33]
- Modified the *pro-forma* tariff to permit the filing of an unexecuted network operating agreement to avoid delaying the commencement of service in the event the customer and the transmission provider cannot agree on all the terms of service.[34]
- Clarified that a transmission provider should not receive double payments for providing either transmission service or ancillary services to

29. Order Clarifying Order No. 888 Reciprocity Condition and Requesting Additional Information, 79 F.E.R.C. ¶ 61,182, at 61,867 (1997).

30. Order No. 888-B, at 62,072.

31. Order No. 888-B, at 62,078. *See also* Order No. 888-A, at 30,285; *Duke Power Co.*, 81 F.E.R.C. ¶ 61,010, at 61,047 (citing *Public Serv. Elec. & Gas Co.*, 78 F.E.R.C. ¶ 61,119, at 61,456, n.7 (1997)), *reh'g denied*, 81 F.E.R.C. ¶ 61,312 (1997).

32. Order No. 888-B, at 62,085.

33. Order No. 888-B, at 62,089.

34. Order No. 888-B, at 62,095.

the same portion of a transmission customer's load.[35]

c. Tariff Implementation and Compliance Issues

i. Compliance Filings

In late 1996 and early 1997, the FERC issued a series of orders on the non-rate terms and conditions of the *pro-forma* tariffs filed by public utilities in response to Order No. 888. The FERC accepted proposed deviations to the *pro-forma* tariff that reflect regional practices, based on the public utility's "good faith representation that the identified regional practice is legitimate."[36] In this regard, the FERC generally accepted the scheduling deadlines and other regional practices proposed by utilities, but did not hesitate to reject modifications that were not supported as regional practices.[37] The FERC accepted the proposed available transmission capability (ATC) assessment methodologies, with certain modifications to ensure comparable treatment of customers; the FERC again declined to require a generic ATC methodology applicable to all utilities.[38] The FERC also required utilities to submit more detailed system impact study methodologies that identify the "key components of the analytical process."[39] Finally, the FERC accepted network service and operating agreements as "prototypes" subject to later modification to address the circumstances of individual network customers. Other utilities that did not include such agreements in their tariffs were directed to submit, at a minimum, a "summary of principles and list of issues to be addressed" in the network service and operating agreements.[40]

The FERC rejected all other deviations from the *pro-forma* tariff that were not specifically permitted by the tariff. The FERC noted that modifications to the *pro-forma* tariff could be sought in Section 205 proceedings.[41] The FERC also explained that a number of issues raised with respect to the Order No. 888 compliance filings were not ripe or could be addressed in the service agreements on rehearing of Order No. 888 or in other proceedings.[42]

ii. Other Compliance Issues

In a July 31, 1997, omnibus order on compliance tariff rates,[43] the FERC

35. Order No. 888-B, at 62,096.

36. *Allegheny Power Sys., Inc.*, 77 F.E.R.C. ¶ 61,266, at 62,100 (1996) [hereinafter *Allegheny*] (citing *Atlantic City Elec. Co.*, 77 F.E.R.C. ¶ 61,144, at 61,532 (1996) [hereinafter *Atlantic City*]; *American Elec. Power Serv. Corp.*, 78 F.E.R.C. ¶ 61,070, at 61,259 (1997) [hereinafter *AEP*] (citing *Atlantic City*). *Atlantic City* is discussed in *Report of the Committee on Electric Utility Regulation*, 18 ENERGY L.J. 197, 228-29 (1997).

37. *Allegheny*, 77 F.E.R.C. ¶ 61,266, at 62,100-01; *AEP*, 78 F.E.R.C. ¶ 61,070, at 61,259-62.

38. *Allegheny*, 77 F.E.R.C. ¶ 61,266, at 62,102-03; *AEP*, 78 F.E.R.C. ¶ 61,070, at 61,262-63.

39. *Allegheny*, 77 F.E.R.C. ¶ 61,266, at 62,103; *AEP*, 78 F.E.R.C. ¶ 61,070, at 61,263-64.

40. *Allegheny*, 77 F.E.R.C. ¶ 61,266, at 62,103-04; *AEP*, 78 F.E.R.C. ¶ 61,070, at 61,264.

41. *Allegheny*, 77 F.E.R.C. ¶ 61,266, at 62,104-05; *AEP*, 78 F.E.R.C. ¶ 61,070, at 61,264-66.

42. *Allegheny*, 77 F.E.R.C. ¶ 61,266, at 62,105-08; *AEP*, 78 F.E.R.C. ¶ 61,070, at 61,266-69.

43. *Allegheny Power Sys., Inc.*, 80 F.E.R.C. ¶ 61,143 (1997).

accepted for filing, those compliance tariffs that made only rate changes "necessitated" by Order No. 888: (i) changes in the structure of ancillary services and the addition of a requirement that rates be separately stated for each ancillary service; (ii) the change in the minimum term for firm point-to-point transmission service from one hour to one day; and (iii) the addition of penalty charges for unauthorized use or excess use of services.[44] The FERC rejected rate changes other than those "necessitated" by Order No. 888.[45]

In the July 31 omnibus order, the FERC also clarified the compliance tariff implementation procedures: Any customer that had executed a service agreement or was taking service under a utility's open access transmission tariff filed prior to the issuance of Order No. 888 was automatically transferred to that utility's compliance tariff on July 9, 1996 (the effective date of Order No. 888).[46]

Public utilities were also directed to file service agreements placing themselves under their own open access transmission tariffs for use on their own system.[47] The FERC required the transmission providers in those filings to comply with the requirements of their tariffs and to provide the operational conditions and limitations under which they engage in point-to-point and network transmission service.[48] For example, the FERC has directed utilities to revise their service agreements to designate the individual network loads of network customers and to specify network resources.[49]

The FERC also has taken a hard line with respect to public utilities' filings of service agreements under the open access transmission tariffs. The FERC has not hesitated to reject filings that do not comply with the terms and conditions of the tariff.[50]

The FERC, in the July 31 omnibus order, disposed of a number of other rate issues on a summary basis. As to rates for ancillary services, for example, the FERC held that companies could offer packages of ancillary services bundled together, but that they must also offer such services on an unbundled, separately-priced basis.[51] As to transmission service rate issues, the FERC imposed a cap on penalty provisions for excessive use of transmission

44. *Id.* at 61,528-29.

45. *Id.* at 61,529. The three most common unacceptable changes were "(i) the adoption of a twelve-monthly coincident peak (12-CP) divisor for firm point-to-point transmission service; (ii) updating the test year to develop revised transmission rates; and (iii) [the] adoption of a new formula for formulary rates." *Id.* at 61,529-30.

46. *Allegheny Power Sys., Inc.*, 80 F.E.R.C. ¶ 61,143, at 61,531 (1997).

47. *See Allegheny Power Sys., Inc.*, 80 F.E.R.C. ¶ 61,143, at 61,536-37 (1997); *Sierra Pacific Power Co.*, 80 F.E.R.C. ¶ 61,376, at 61,271-72 (1997).

48. *Virginia Elec. and Power Co.*, 81 F.E.R.C. ¶ 61,125, at 61,612 (1997) [hereinafter *Virginia*].

49. *See, e.g., MidAmerican Energy Co.*, 81 F.E.R.C. ¶ 61,194, at 61,856 (1997); *Virginia*, 81 F.E.R.C. at 61,613; *Florida Power Corp.*, Docket No. ER97-4461-000 (Oct. 22, 1997) (Letter Order).

50. *See, e.g., Western Resources, Inc.*, 81 F.E.R.C. ¶ 61,269 (1997) (rejecting transaction-specific transmission service agreements for failure to specify the actual receipt and delivery points and directing the service agreements to be revised to reflect specifically whether or not each of the six ancillary services would be provided under the service agreements).

51. *Allegheny Power Sys., Inc.*, 80 F.E.R.C. ¶ 61,143, at 61,539-40.

services at a level equal to twice the standard rate for the service at issue,[52] adopted minimum periods of time before a transmission provider may assess a penalty for failure to curtail,[53] and clarified that where a transmission provider has not proposed an express crediting provision for the interruption of non-firm point-to-point customers, the transmission provider must compute its bill to an interrupted non-firm customer as if the term of service actually rendered were the term of service reserved.[54]

The FERC also addressed proposals on a company-specific basis. For example, the FERC rejected a public utility's proposal to purchase four of the six ancillary services under its proposed wholesale generation tariff because the utility must obtain the services under the open access transmission tariff just like any third-party customer.[55] The FERC also held that the functional unbundling requirement may not be avoided simply by renegotiating a pre-existing (*i.e.*, before July 9, 1996) agreement during the original term of the agreement. The FERC noted that otherwise the unbundling requirement "could be avoided indefinitely as long as each new agreement was negotiated during the term of the then-existing agreement."[56]

The FERC also announced a policy with respect to the filing of power sales agreements or tariffs. As part of the functional unbundling of wholesale services required by the Open Access Rule, the prices for wholesale generation, transmission, and ancillary services must be separately stated for sales under requirements or coordination contracts executed after July 9, 1996. However, a number of utilities had failed to comply with that requirement. Therefore, the FERC announced that any future filing of a power sales agreement or tariff that failed to provide for unbundling of transmission and ancillary services would be rejected by the FERC.[57] Market-based power sales tariffs must provide that (i) when transmission and ancillary services to effectuate power sales transactions under the market-based tariff are to be obtained by the selling utility, the utility must file a service agreement placing itself under its open access transmission tariff, and (ii) when the customer itself is obtaining transmission and ancillary services from the market-based selling utility, the utility must file a service agreement placing the customer under its open access transmission tariff.[58]

Finally, the FERC accepted for filing, as modified, the joint system-wide

52. *Id.* at 61,545-46. The FERC accepted the penalty provisions in pre-Order No. 888 tariffs (subject to refund) and held that issues regarding penalty provisions of any tariffs set for hearing may be raised at that hearing.

53. The period is ten minutes if the curtailment is for reliability purposes, and twenty minutes if for economic purposes. *Id.* at 61,546.

54. *Id.* at 61,549-50.

55. *Arizona Public Serv. Co.*, 78 F.E.R.C. ¶ 61,016, at 61,068 (1997).

56. *Arizona Public Serv. Co.*, 78 F.E.R.C. ¶ 61,016, at 61,071 n.29 (1997).

57. *Central Hudson Enter. Corp.*, 79 F.E.R.C. ¶ 61,390, at 62,654-55 (1997). The FERC's policy applies to any filing after the date of the order. Filings prior to the date of the order that failed to reflect the unbundling requirement would be held "deficient." *Id.* at 62,655 n.7.

58. *Central Hudson Enter. Corp.*, 79 F.E.R.C. ¶ 61,390, at 62,655 (1997); *Arizona Public Serv. Co.*, 79 F.E.R.C. ¶ 61,022, at 61,100 (1997).

open access tariff submitted by the utility operating companies of the Central and South West Corporation (CSW).[59] Their tariff incorporated the terms and conditions of the *pro-forma* tariff, with additional provisions under which transmission service would be offered consistent with the transmission access and pricing rules of the Texas Public Utilities Commission, and provided for separate transmission rates for service within ERCOT and the Southwest Power Pool. The FERC allowed a number of deviations from the *pro-forma* tariff that reflect ERCOT practices,[60] but rejected other deviations from the *pro-forma* tariff that did not reflect regional practices and were not otherwise justified.[61]

iii. Implementation of the Open Access Tariff

Secondary Receipt and Delivery Points. Under Section 13.7(a) of the *pro-forma* tariff, a customer may obtain service at secondary receipt and delivery points on a firm or non-firm basis. A utility argued that service redirected from one delivery point on a non-firm basis to a different delivery point was subject to separate charges because the customer had not changed its own receipt and delivery points but had "divert[ed] a portion of its transmission service to a second customer's delivery point."[62] The FERC disagreed, explaining that Section 13.7(a) "allows a customer to change its receipt and delivery points without restriction as to load. Any delivery point designated by a customer, whether primary or secondary, would be 'its' delivery point even if the load were different."[63]

Reassignment of Capacity. The FERC clarified that a transmission provider's wholesale merchant function may reassign transmission capacity that is taken under the provider's *pro-forma* tariff.[64] As an eligible customer under the tariff, the transmission provider may reassign its rights to capacity. The FERC also clarified that when the transmission provider's merchant function reassigns capacity, all of the non-rate terms and conditions that otherwise would apply to the transmission provider's sale of transmission capacity continue to apply: "the transmission provider cannot abdicate any of its obligations as a transmission provider under Order Nos. 888 and 888-A, including the posting of discounts and other information, by acting as a reseller of transmission capacity."[65]

Consistent with Order Nos. 888 and 888-A, charges for transmission service reassigned by a transmission provider under its transmission reassignment rate schedule must be capped at a price not to exceed the highest of: (i) the original rate paid by the assignor, (ii) the transmission provider's

59. *Central Power and Light Co.*, 81 F.E.R.C. ¶ 61,311 (1997).

60. *See id.* at 62,434-437. The FERC rejected those provisions for the ERCOT portion of the CSW system that reflected neither the *pro-forma* tariff nor the Texas commission's tariff. *Id.* at 62,437.

61. *Id.* at 62,437-38.

62. *Delmarva Power & Light Co.*, 78 F.E.R.C. ¶ 61,060, at 61,219 (1997).

63. *Id.* at 61,220.

64. *Commonwealth Edison Co.*, 78 F.E.R.C. ¶ 61,312 (1997).

65. *Id.* at 62,336.

maximum filed rate at the time of the transmission reassignment, or (iii) the assignor's own opportunity costs, capped at the transmission provider's cost of expansion at the time of the resale. Incremental opportunity costs in connection with the resale of transmission service may not be charged unless charges for such costs are first filed separately with the FERC.[66]

The FERC also indicated that the requirement that a public utility, in order to reassign transmission rights, have on file a tariff for capacity reassignment applies to *all* public utilities, including power marketers.[67] Power marketers (including the marketing affiliates of public utilities with franchised service territories) must file information with respect to capacity reassignments in their quarterly transaction reports.[68]

Right of First Refusal. The FERC found that a transmission provider's own reservation of its transmission capacity had priority over that of a customer seeking to extend its service. The transmission provider had filed on July 8, 1996 (the day before the effective date of Order No. 888 and the transmission provider's *pro-forma* tariff) a service agreement reserving transmission capacity. Because its pre-Order No. 888 tariff, under which the customer had taken service, did not provide for a right of first refusal, and because it had reserved the disputed transmission capacity prior to the effective date of Order No. 888 and the *pro-forma* tariff, the transmission provider had priority over the customer to the disputed transmission capacity.[69] In short, any right of first refusal by the customer was subject to whatever transmission capacity reservations were already in place -- including the transmission provider's, which had been made the day before the effective date of the *pro-forma* tariff.

Confirmation Procedures. The FERC accepted a utility's addition of confirmation procedures (consisting primarily of time limits for making confirmations of service requests) to its short-term firm point-to-point transmission service agreement. The FERC found the procedures "not . . . unreasonable" and acceptable until industry-wide procedures are adopted by the FERC.[70]

Application for Service. The FERC denied a utility's claims that a customer's application for firm point-to-point transmission service in connection with supplying power to a wholesale load was deficient. The FERC found that the failure to specify a precise service commencement date did not ren-

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66. *See, e.g., Central Vermont Public Serv. Corp.*, 80 F.E.R.C. ¶ 61,203 (1997); *Southwestern Public Serv. Co.*, 80 F.E.R.C. ¶ 61,245 (1997); *Virginia Elec.*, 80 F.E.R.C. ¶ 61,275 (1997); *Public Serv. Co. of Colorado*, 81 F.E.R.C. ¶ 61,134 (1997).

67. *Southwestern Public Serv. Co.*, 80 F.E.R.C. ¶ 61,245, at 61,906 (1997). The FERC, citing Order Nos. 888 and 888-A, also rejected an argument that such a filing requirement would be "unduly burdensome" and "serve no purpose." *Id.*

68. *Enron Power Marketing, Inc.*, 81 F.E.R.C. ¶ 61,277 (1997); *Griffin Energy Marketing, L.L.C.*, 81 F.E.R.C. ¶ 61,133, at 61,629 (1997).

69. *Long Island Lighting Co. v. Northeast Utilities Serv. Co.*, 79 F.E.R.C. ¶ 61,384, at 62,634-35, *reh'g denied*, 80 F.E.R.C. ¶ 61,315 (1997).

70. *Commonwealth Edison Co.*, 80 F.E.R.C. ¶ 61,167, at 61,719 (1997). *See also Wisconsin Elec. Power Co.*, 80 F.E.R.C. ¶ 61,299 (1997) (approving similar confirmation procedures).

der the application deficient, because the customer's original plans to initiate service had been frustrated by legal proceedings instituted by the transmission provider. The FERC also directed the utility to evaluate the requested transmission capacity, which included a range of figures, and to treat any additional amounts requested as a modified application under the *pro-forma* tariff. Finally, the FERC held that the *pro-forma* tariff does not require that delivery points be in existence on the date of the application; applications for future service can reference future delivery points and, when they do, need not separate reservations among such future delivery points (since any such attempt would be premature).[71]

Waiver of Deposit. The FERC accepted a utility's proposed revision to the *pro-forma* tariff to allow it to waive, in certain circumstances, the deposit requirement for applications for firm point-to-point transmission service. Where the customer already has established its creditworthiness, the utility would waive the deposit requirement and bill the customer for its reasonable costs in evaluating the application.[72]

Conditional Reservations. In a complaint proceeding, the FERC addressed the issue of whether a transmission customer with a conditional reservation for short-term firm point-to-point service has the right to match a use by a long-term network customer under section 13.2 of the *pro-forma* tariff. The FERC explained that only competing short-term firm point-to-point requests triggered the matching option under section 13.2, *i.e.*, a short-term customer may match a competing long-term request before having its reservation bumped. The matching option is available "strictly for the purpose of rationing, during the conditional reservation period, ATC between competing short-term firm uses. It is not for the purpose of allowing a short-term customer to bump a long-term customer."[73] Therefore, the transmission provider (a long-term network customer) was not required to offer the short-term customer a matching option before canceling its conditional short-term point-to-point reservation.

Use of Interface Capacity by Network Customer. In a dispute between a utility and its network customer, with respect to the customer's attempted designation of network resources at the utility's interface with the customer's new power supplier, the FERC explained that, while there is no "load ratio" limitations on a network customer's use of interfaces in designating network resources, the issue of the amount of capacity available for new transmission service is to be addressed in accordance with the *pro-forma* tariff's application procedures, including a determination of ATC for the new service.[74] The FERC set for hearing factual issues with respect to the amount of interface capacity available and the upgrades that would be required to serve the cus-

71. *Southwestern Public Serv. Co. v. El Paso Elec. Co.*, 80 F.E.R.C. ¶ 61,159, at 61,696-97 (1997).

72. *Commonwealth Edison Co.*, 80 F.E.R.C. ¶ 61,353, at 62,210-11 (1997).

73. *Madison Gas & Elec. Co. v. Wisconsin Power & Light Co.*, 80 F.E.R.C. ¶ 61,331, at 62,102-03 (1997).

74. *Sierra Pacific Power Co.*, 81 F.E.R.C. ¶ 61,136, at 61,637-38 (1997). Nor was the transmission provider required to "provide service for which there is inadequate firm capacity and then to respond to those problems through redispatch where the costs are shared by all network users." *Id.* at 61,639.

tomer.[75]

Network Transmission Rate Calculation. A utility's unopposed proposal "to revise the calculation of network transmission rates to adjust the load ratio share once a year, rather than each month on a rolling basis," was accepted by the FERC. The utility stated that the change would "significantly reduce administrative costs" and would be "revenue neutral."[76]

Unbundled Retail Transmission Service. The FERC requires unbundled retail transmission service to be taken under the terms and conditions of the *pro-forma* tariff. Absent a request by a state commission for a separate tariff or variations in the *pro-forma* tariff (and the FERC's agreement thereto), a proposed retail transmission service tariff that deviates from the *pro-forma* tariff will be rejected.[77] The FERC granted requests for variations from the *pro-forma* tariff to accommodate retail transmission service.[78]

d. Tariff Modifications

In addition to deviations from the *pro-forma* tariff expressly permitted to accommodate regional practices, the FERC addressed many of the proposed modifications to the *pro-forma* tariff in series of orders on non-rate terms and conditions in early 1997. Other modifications were addressed in utility-specific orders.[79]

For example, the FERC accepted Florida Power Corporation's (FPC) network contract demand transmission service (NCDTS), which incorporates some of the features of both point-to-point and network transmission service under the *pro-forma* tariff.[80] The FERC found NCDTS provided additional benefits above the *pro-forma* tariff, while services under the *pro-forma* tariff remain available without an increase in rates but directed the FPC to modify the service to ensure comparable treatment of customers.[81] The FERC also noted that "it would be much preferable for departures" from the *pro-forma* tariff to be "proposed on a regional basis within the context of a proposed ISO."[82] Regional proposals will give the FERC "greater confidence" that a proposed departure is consistent with or superior to the *pro-forma* tariff and

75. *Id.* at 61,638.

76. *Wisconsin Elec. Power Co.*, 80 F.E.R.C. ¶ 61,299, at 62,049 (1997).

77. *Portland Gen. Elec. Co.*, 78 F.E.R.C. ¶ 61,219, at 61,950-51 (1997).

78. *See, e.g., Washington Water Power Co.*, 81 F.E.R.C. ¶ 61,360 (1997); *Allegheny Power Serv. Corp.*, 81 F.E.R.C. ¶ 61,271 (1997); *Niagara Mohawk Power Corp.*, 81 F.E.R.C. ¶ 61,180 (1997).

79. *See, e.g., Arizona Public Serv. Co.*, 78 F.E.R.C. ¶ 61,083 (1997); *Commonwealth Edison Co.*, 78 F.E.R.C. ¶ 61,090 (1997); *Tucson Elec. Power Co.*, 78 F.E.R.C. ¶ 61,091 (1997); *Maine Public Serv. Co.*, 78 F.E.R.C. ¶ 61,113 (1997); *New York State Elec. & Gas Corp.*, 78 F.E.R.C. ¶ 61,114 (1997); *New York State Elec. & Gas Corp.*, 79 F.E.R.C. ¶ 61,371 (1997); *Pennsylvania-New Jersey-Maryland Interconnection*, 80 F.E.R.C. ¶ 61,069 (1997); *Florida Power Corp.*, 81 F.E.R.C. ¶ 61,247 (1997); *Wolverine Power Supply Coop., Inc.*, 81 F.E.R.C. ¶ 61,369 (1997); *Maine Public Serv. Co.*, 78 F.E.R.C. ¶ 61,113 (1997).

80. *Florida Power Corp.*, 81 F.E.R.C. ¶ 61,247, at 62,065 (1997).

81. *Id.* at 62,067.

82. *Id.* at 62,067 n.15.

will eliminate any patchwork of terms and conditions.[83]

However, the FERC rejected a proposal to replace the entire *pro-forma* open access tariff with a "unified service arrangement" tariff that included load-based pricing for transmission services through or outside of the transmission provider's system. The FERC could not "tell on the basis of the information provided by [the utility] whether its proposal will result in service consistent with or superior to the services provided in the *pro-forma* tariff."[84] The FERC gave the utility the option of proceeding with a hearing on the tariff or making a new filing.[85]

e. Tariffs of Non-Jurisdictional Transmission Providers

In accordance with the "safe harbor" procedures, several transmission-owning utilities not subject to the FERC's general "public utility" jurisdiction sought, and were granted, declaratory orders finding their transmission tariffs satisfied the FERC's comparability standards and were therefore acceptable reciprocity tariffs under the *pro-forma* tariff.[86] Under the safe-harbor procedures, if the FERC finds that the terms and conditions of a non-public utility's transmission tariff are consistent with or superior to those of the *pro-forma* tariff, the FERC will deem it to be an acceptable reciprocity tariff and require public utilities to provide open access transmission service upon request to that particular non-public utility.[87] In addition, the reciprocity provision in the *pro-forma* tariff extends to members of power pools or regional transmission groups (RTGs); therefore, a non-public utility would be subject to reciprocity regarding service to the other members of the pool or RTG.[88]

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83. *Id.*

84. *Duquesne Light Co.*, 78 F.E.R.C. ¶ 61,115, at 61,445 (1997).

85. *Id.*

86. *See, e.g.*, *Orlando Utilities Commission*, 81 F.E.R.C. ¶ 61,397 (1997) [hereinafter *OUC*] (municipal electric utility); *Colorado Springs Utilities*, 81 F.E.R.C. ¶ 61,191 (1997) [hereinafter *Colorado Springs*] (municipal electric utility); *Hoosier Energy Rural Elec. Coop.*, 81 F.E.R.C. ¶ 61,153 (1997) [hereinafter *Hoosier*] (RUS-financed generation and transmission cooperative); *Omaha Public Power District*, 81 F.E.R.C. ¶ 61,054 (1997) [hereinafter *Omaha*] (political subdivision of state); *Southern Illinois Power Coop.*, 80 F.E.R.C. ¶ 61,341 (1997) [hereinafter *Southern Illinois*] (RUS-financed generation and transmission cooperative); *United States Dept. of Energy - Bonneville Power Admin.*, 80 F.E.R.C. ¶ 61,119, *order on reh'g*, 81 F.E.R.C. ¶ 61,165 (1997) [*Bonneville*] (federal power marketing agency); *South Carolina Public Serv. Authority*, 80 F.E.R.C. ¶ 61,180, *reh'g denied*, 81 F.E.R.C. ¶ 61,192 (1997) [*Santee Cooper*] (state authority). *See also East Kentucky Power Coop., Inc.*, Docket No. NJ97-14-000 (Letter Order) (Dec. 18, 1997) (RUS-financed generation and transmission cooperative); *Southern Minnesota Mun. Power Agency*, Docket No. NJ97-12-000 (Letter Order) (Nov. 13, 1997) (municipal power agency). The Western Area Power Administration (Western) and Southwestern Power Administration (Southwestern) also have filed reciprocity tariffs with the FERC. *See* Docket Nos. NJ98-1-000 (Western) and NJ98-2-000 (Southwestern).

87. *See, e.g.*, *OUC*, 81 F.E.R.C. at 62,825; *Colorado Springs*, 81 F.E.R.C. at 61,848-49; *Hoosier*, 81 F.E.R.C. at 61,694.

88. *See, e.g.*, *Omaha*, 81 F.E.R.C. at 61,269 (Omaha is subject to reciprocity regarding service to other members of the Mid-Continent Area Power Pool (MAPP)). In *Omaha*, the FERC declined Omaha's request that it establish a presumption that a FERC-approved reciprocity tariff necessarily satisfies the comparability requirements imposed by MAPP on its members. *Omaha*, 81 F.E.R.C. at 61,270.

Generally, the reciprocity tariffs have conformed to the terms and conditions of the *pro-forma* tariff. The FERC has required the non-public utilities to conform their tariffs to the non-rate terms of the *pro-forma* tariff revised in Order Nos. 888-A and 888-B.[89] The FERC also rejected challenges to the non-rate terms and conditions of the reciprocity tariffs that were collateral attacks on the non-rate terms and conditions of the *pro-forma* tariff.[90]

In addition to changes to reflect regional practices,[91] the reciprocity tariffs also contain minor deviations from the *pro-forma* tariff to reflect the non-jurisdictional status of the utilities.[92] The FERC also allowed a modification to the *pro-forma* tariff to reflect a cooperative's limited resources; the cooperative was allowed to respond to a request for determination of ATC within sixty minutes, rather than the thirty minutes required by the *pro-forma* tariff, because it had only a limited number of transmission personnel to handle such requests.[93] Finally, the FERC has accepted changes designed to ease administrative burdens.[94]

However, the FERC rejected a number of proposed reciprocity tariff provisions as unjustified or unexplained deviations from the *pro-forma* tariff. For example, the FERC found "unacceptable for a reciprocity tariff" the failure to include power marketers expressly within the definition of "eligible customer,"[95] the use of deadlines for requests for non-firm service that are inconsistent with and inferior to the *pro-forma* tariff's advance notice provisions,[96] the use of service agreements that are not consistent with or superior to the service agreements in the *pro-forma* tariff,[97] and the use of an energy deviation band in the energy imbalance schedule of one megawatt instead of two megawatts.[98]

Finally, the FERC has denied all protests of proposed rates under the

89. *See, e.g.*, *OUC*, 81 F.E.R.C. at 62,826 (requiring revising of tariff to conform with the one change to the *pro-forma* tariff under Order No. 888-B); *Colorado Springs*, 81 F.E.R.C. at 61,849 (requiring revising of tariff to conform to the *pro-forma* tariff under Order No. 888-A); *Hoosier*, 81 F.E.R.C. at 61,695 (requiring revising of tariff to conform to the *pro-forma* tariff under Order No. 888-A); *Santee Cooper*, 80 F.E.R.C. at 61,742 and 81 F.E.R.C. at 61,853 (approving changes to reciprocity tariff filed to conform to *pro-forma* tariff under Order Nos. 888 and 888-A).

90. *See, e.g.*, *Southern Illinois*, 80 F.E.R.C. at 62,127 and n.7; *Santee Cooper*, 80 F.E.R.C. at 61,742 and n.3. The FERC also rejected as collateral attacks on Order Nos. 888 and 888-A challenges to the FERC's standard of review of reciprocity tariffs. *Santee Cooper*, 81 F.E.R.C. at 61,851-52.

91. *E.g.*, *Southern Illinois*, 80 F.E.R.C. at 62,128 (changes to reflect regional scheduling deadlines).

92. *Southern Illinois*, 80 F.E.R.C. at 62,127-28.

93. *Southern Illinois*, 80 F.E.R.C. at 62,128.

94. *Bonneville*, 80 F.E.R.C. at 61,373.

95. *Bonneville*, 80 F.E.R.C. at 61,374.

96. *Bonneville*, 80 F.E.R.C. at 61,375. On rehearing, the FERC granted Bonneville's request that it be allowed to demonstrate in its compliance filing that its alternative scheduling deadlines are reasonable and generally accepted in the region. *Bonneville*, 81 F.E.R.C. at 61,722.

97. *Bonneville*, 80 F.E.R.C. at 61,375-76. The FERC also held that Bonneville could tailor its service agreements to fit the individual circumstances of individual customers, but that it must still abide by its published tariffs and cannot treat individual customers in an unduly discriminatory or preferential fashion. *Bonneville*, 80 F.E.R.C. at 61,376.

98. *OUC*, 81 F.E.R.C. at 62,826.

reciprocity tariffs. To determine if proposed reciprocity rates are consistent with the FERC's comparability standards, the non-public utility must submit "sufficient information [for the Commission] to conclude that the non-public utility's rate is comparable to the rate it charges others."[99] If the FERC concludes, based on the submitted information, that the proposed rates for transmission and ancillary services are comparable to the rates it charges itself, then the FERC will find that the tariff meets the standard for an acceptable reciprocity tariff.[100]

f. Section 211 Complaints

During 1997, the FERC issued only a handful of decisions concerning applications filed under sections 211 and 212 of the FPA.[101] These cases addressed an assortment of issues.

In *Missouri Basin Municipal Power Agency,*[102] the FERC set for hearing the question of whether the requested transmission service could be provided over a discrete portion of certain interconnected facilities. The applicant, Missouri Basin Municipal Power Agency (Missouri Basin), requested the FERC to order the Western Area Power Authority (WAPA) to provide various types of transmission service, using only the federally-owned portion of the Joint Transmission System established under the Missouri Basin Systems Group Pooling Agreement, which also includes facilities owned by a group of municipals and cooperatives. WAPA contended that the federally-owned facilities could not reliably provide the service, and instead offered Missouri Basin service over the integrated system's federal and non-federal facilities. Missouri Basin contended: (i) that the non-federal facilities were unnecessary for the service it required; and (ii) that the comparability principle required WAPA to provide the federal-only service to third parties because WAPA itself has, under the Joint Transmission System Agreement, taken transmission service that utilized only the federal facilities. Without discussing the comparability argument, the FERC set for hearing the issue of whether the requested transmission services could be provided without impairing the continued reliability of affected electric systems.

Cinergy Services, Inc.,[103] (Cinergy) involved an application for an order directing the Tennessee Valley Authority (TVA) to deliver power to the City of Bristol, formerly a requirements customer of the TVA. Cinergy contended that, although the TVA agreed to provide network transmission service, it had unreasonably sought to condition the service. In its application, Cinergy asked the FERC to resolve three issues: (i) whether the TVA

99. *OUC*, 81 F.E.R.C. at 62,826 (1997) (quoting Order No. 888, at 31,761). *See also Colorado Springs*, 81 F.E.R.C. at 61,849 (1997); *Hoosier*, 81 F.E.R.C. at 61,695 (1997) (both quoting Order No. 888, at 31,761).

100. *OUC*, 81 F.E.R.C. at 62,826 (1997); *Colorado Springs*, 81 F.E.R.C. at 61,849 (1997); *Hoosier*, 81 F.E.R.C. at 61,695 (1997).

101. 16 U.S.C. §§ 824j, 824k (1997).

102. 81 F.E.R.C. ¶ 61,324 (1997).

103. 81 F.E.R.C. ¶ 61,243 (1997).

could demand stranded cost reimbursement as a condition to the service; (ii) whether the TVA should have the right to unilaterally modify the rates, terms and conditions of the service; and (iii) whether TVA's transmission rate to Cinergy should be capped at the transmission component of the TVA's retail rate to industrial customers.

Although the TVA's requirements contract with Bristol contained a four-year notice provision which created a rebuttable presumption of no reasonable expectation of continued service, the FERC set the stranded cost issue for hearing. The FERC noted that the TVA had made arguments "regarding its 20- to 25-year planning horizon" and that Bristol had paid construction work in progress on new TVA projects without objection. However, the FERC refused to uphold the TVA's claim that it could unilaterally implement changes to the initial rate to be charged for transmission services ordered under sections 211 and 212 of the FPA. Rather, the FERC reaffirmed its policy of employing procedures similar to those under FPA sections 205 and 206 for transmitting utilities that are not public utilities.[104] Accordingly, said the FERC, the TVA could file proposed rate changes upon 60-days' prior notice, during which time the FERC would act on the proposal. In addition, the transmission customer could file a complaint, which would be acted upon as soon as possible. To further accommodate the TVA's desire to implement proposed rate changes without delay, the FERC also stated that upon request by a party or on its own motion, a rate change could be effectuated on an interim basis, subject to refund.[105]

The FERC next considered Cinergy's request to "cap" the network transmission rates charged by the TVA at the transmission component of the rates the TVA charges to its retail customers. The request was motivated by Cinergy's concern that the TVA was attempting to "cherry-pick" Bristol's industrial customers by offering to undercut Bristol's retail prices. Putting aside the parties' jurisdictional arguments,[106] the FERC declared that its obligation to establish non-discriminatory rates under section 212(a)[107] "may require us to . . . ensure that there is no undue discrimination between the transmission costs" recovered in the TVA's retail rates and the rates for section 211 transmission service.[108] Nevertheless, the FERC rejected Cinergy's proposed rate-cap condition because Cinergy had not specifically objected to any aspect of the rate level or methodology the TVA proposed for its net-

104. *See Minnesota Mun. Power Agency*, 68 F.E.R.C. ¶ 61,060, at 61,208 (1994).

105. Establishing interim rates, the FERC observed, would be consistent with its decisions in previous cases in interim rates were implemented in connection with final orders requiring transmission service when insufficient information was available to establish final rates with precision. The FERC cited a number of cases in which it had employed this procedure: *City of College Station*, 76 F.E.R.C. ¶ 61,138, at 61,744 (1996); *Tex-La Elec. Coop. of Texas, Inc.*, 69 F.E.R.C. ¶ 61,269, at 62,043 (1994), *reh'g pending*.

106. Because TVA's rates are not state-regulated, Cinergy claimed, its rate-cap request did not implicate the jurisdictional concerns cited by the FERC in Order No. 888 in deciding not to order retail unbundling. TVA asserted, in response, that Cinergy's request amounted to asking the FERC to unbundle its retail rates, stating that such a requirement had not even been imposed on public utilities.

107. 16 U.S.C. § 824k(a) (1997).

108. 81 F.E.R.C. ¶ 61,243, at 62,150 (1997).

work transmission service.

In *City of College Station, Texas*,[109] the FERC interpreted section 212(k) of the FPA,[110] which pertains to requests for transmission service to be provided in whole or in part within the Electric Reliability Council of Texas (ERCOT) by ERCOT non-public utilities. Section 212(k) requires that in setting the compensation for such services the FERC must defer, "insofar as practicable and consistent with subsection [212](a)," to the ratemaking methodology used by the Public Utility Commission of Texas (TPUC).[111]

The FERC had made a preliminary determination that an order requiring the City of Bryan, Texas (Bryan), and the Texas Municipal Power Agency (TMPA) to deliver electric energy from Texas Utilities Electric Company to College Station, would meet the standards of sections 211 and 212 of the FPA, and directed the parties to negotiate the rates, terms, and conditions of the transmission service "after the Texas Commission *establishes* a rate for Bryan's and TMPA's wholesale transmission services to College Station . . . ."[112] The question in *College Station II* was one of timing -- at what point in the course of a series of orders issued in connection with Texas' open access transmission initiative did the TPUC's transmission ratemaking methodology become sufficiently *established* such that the parties should begin negotiations. That guidepost was reached, said the FERC, when the TPUC set permanent ERCOT-wide transmission rates. In so ruling, the FERC rejected contentions that: (i) the appropriate juncture had been reached earlier in the TPUC proceeding, where TPUC set temporary rates for transmission service to College Station but explicitly said that they were to be replaced by permanent ERCOT-wide transmission rates as soon as they were established; and (ii) the appropriate juncture would not be reached until the TPUC's order became final under Texas law.

2. Order Nos. 889-A and 889-B

Order No. 889 obligates any public utility that owns, operates, or controls facilities used for the transmission of electric energy in interstate commerce to develop or participate in an Open Acess Same-Time Information System (OASIS) and abide by certain standards of conduct.[113]

Order No. 888-A made changes in the policy on discounts and necessitated that the FERC enact amendments to the posting requirements and

109. 80 F.E.R.C. ¶ 61,375 (1997) [hereinafter *College Station II*].

110. 16 U.S.C. § 824k(k)(1) (1997).

111. 16 U.S.C. § 824k(k)(1) (1997).

112. *City of College Station, Texas*, 76 F.E.R.C. at 61,741-43, 61,745-47 (1996) [hereinafter *College Station I*] (emphasis added).

113. Order 889, *Open Access Same-Time Information System (formerly Real-Time Information Network) and Standards of Conduct*, 61 Fed. Reg. 21,737 (1996), F.E.R.C. STATS. & REGS., Regulations Preambles January 1991 - June 1996 ¶ 31,035 (1996); Order No. 889-A, *order on reh'g*, 62 Fed. Reg. 12,484 (1997), III F.E.R.C. STATS. & REGS. ¶ 31,049 (1997); Order No. 889-B, *rehearing denied*, 62 Fed. Reg. 64,715 (December 9, 1997), 81 F.E.R.C. ¶ 61,253 (1997) [hereinafter Order No. 889 or Order No. 889-A or Order No. 889-B, respectively].

standards of conduct which the FERC did in Order No. 889-A.[114] Order No. 889-A requires a utility to publicize on an OASIS--and may do so anywhere else--any offer of discounts on basic transmission service. The same rule applies to discounts on ancillary services in support of the transmission provider's basic transmission service. On the other hand, a utility need not post on OASIS offers of discounts for other ancillary services.

Order No. 889-A also changes the content of notification. Utilities must post transactions involving affiliates and unaffiliated providers in the same fashion, except that identifying the affiliate and the identity of parties may no longer be masked. Except for next-hour service, parties must post requests for transmission and ancillary services on the OASIS before utilities respond to them.

Implementation of the OASIS proceeded along two lines: the OASIS working groups and compliance filings. In Order No. 889-A, the FERC declared that all negotiations between transmission providers and customers must take place on the OASIS and directed the How Working Group to propose the necessary changes in the Standards and Protocol document to accomplish that goal. However, the FERC suspended, until after review of the How Working Group's report, (1) the requirement in Order No. 889 and 889-A that the data elements that comprise the templates in the OASIS Standards and Protocols document be fixed in sequence and number, without any additions or deletions, and not differ from OASIS node to OASIS node; and (2) the requirement that all ancillary services provided in support of basic transmission service be purchased exclusively and individually in transactions conducted on the OASIS.[115]

Recently, the FERC ordered utilities to post on the OASIS organization charts and job descriptions for transmission and marketing departments as well as parts of the company involved in retail wheeling.[116] Utilities must indicate which generation and ancillary services employees perform marketing duties and which deal with transmission. The FERC Hotline will furnish guidance in writing to utilities seeking clarification of the standards, such as what matters employees may communicate outside the OASIS. Utilities must also indicate the type of security they will create to ensure separation of information between marketers and transmission employees. The FERC ordered utilities to revise their standards of conduct accordingly.

A waiver of the OASIS requirements is appropriate (1) if the applicant owns, operates, or controls only limited and discrete transmission facilities, or (2) if the applicant is a small public utility[117] that owns, operates, or controls an integrated transmission grid, unless it is a member of a tight power pool, or other circumstances are present which indicate that waiver would not be

114. *Id.*

115. *OASIS How Working Group*, 79 F.E.R.C. ¶ 61,156 (1997).

116. *American Elec. Power Serv. Corp.*, 81 F.E.R.C. ¶ 61,332 (1997).

117. To qualify as a small public utility, the applicant must meet the Small Business Administration definition of a small electric utility, *i.e.*, disposes of no more than 4 million Mwh of electricity annually. 81 F.E.R.C. ¶ 61,369, at n.23 (citing Order No. 888, at 31,896-97).

justified.[118] Any waivers of Order No. 889 will remain effective until the FERC takes action in response to a complaint.[119] The FERC will consider requests for waivers of Order No. 889 made by non-public utilities using the same standards it applies to requests for waiver made by public utilities.[120]

The FERC permits, but does not require, utilities to use a regional OASIS.[121] While it is acceptable to post a notice about approved changes in tariff terms and conditions on the OASIS, any revised terms and conditions must be reflected in the tariff and cannot be self-effected by reporting them on the OASIS.[122] The FERC has established a timetable for available ATC implementation based upon implementation of Phase II of the OASIS. Until Phase II of OASIS implementation is completed, the FERC will entertain complaints that the ATC was computed improperly or that it is being applied with undue discrimination, but will not entertain complaints that the descriptions are unclear or not standardized.[123]

3. Deregulation of Power Sales: Market-Based Pricing

At the end of 1997, 300 independent marketers (i.e., unaffiliated with a public utility) had received authority from the FERC to charge market-based rates for wholesale sales of energy and capacity; ten applications were pending. Seventy-nine marketers affiliated with a public utility had received market rate authority; twelve applications were pending. Sixty-two investor-owned public utilities had received authority; six were pending. Finally, nine non-FERC-regulated entities had received market-rate authority; three applications were pending.

a. Inter-Affiliate Transactions

The FERC generally precludes a market-rate applicant from selling power to or purchasing power from an affiliate[124] except pursuant to a separate filing under Section 205 of the FPA. Most efforts by utilities to limit the scope of this requirement have not been successful.[125]

The FERC, however, did accept tariff amendments filed by Detroit Edison Company (Detroit Edison) that would allow it to sell power to affiliates

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118. *Wolverine Power Supply Coop., Inc.*, 81 F.E.R.C. ¶ 61,369 (1997); *Soyland Power Corp.*, 78 F.E.R.C. ¶ 61,095, at 61,340 (1997).

119. *Central Minnesota Muni. Power Agency*, 79 F.E.R.C. ¶ 61,260 (1997).

120. *Southern Illinois Power Coop.*, 80 F.E.R.C. ¶ 61,341 (1997).

121. *American Elec. Power Serv. Corp.*, 78 F.E.R.C. ¶ 61,070 (1997).

122. *Id.* at 61,268. *See also Allegheny Power Sys., Inc.*, 80 F.E.R.C. ¶ 61,143, at 61,547 (1997).

123. *American Elec. Power Serv. Corp.*, 78 F.E.R.C. ¶ 61,070, at 61,262-61,263. *See also Madison Gas & Elec. Co. v. Wisconsin Power & Light Co.*, 80 F.E.R.C. ¶ 61,331 (1997) (order addressing complaint regarding ATC postings on OASIS).

124. Note that once a utility publicly releases its intention to merge with another utility or utilities, the FERC will rescind that utility's ability to sell or purchase energy at market-based rates to the companies it intends to merge with, even before any merger pleadings are filed. *See Delmarva Power & Light Co.*, 76 F.E.R.C. ¶ 61,331, at 62,583 (1996).

125. *See, e.g., Consolidated Edison of New York, Inc.*, 78 F.E.R.C. ¶ 61,298 (1997); *American Elec. Power Serv. Corp.*, 81 F.E.R.C. ¶ 61,129 (1997); *Virginia Elec. Power Co.*, 80 F.E.R.C. ¶ 61,275 (1997).

at negotiated rates subject to a cost-based price cap.[126] Detroit Edison represented that sales under the proposed tariff would be at a price no lower than its system's incremental cost of energy, and no higher than the cost-based price caps set forth in another previously-accepted Detroit Edison tariff that provided for cost-based sales to unaffiliated customers. Detroit Edison committed in the filing that if it sells to DTE Energy Trading at a discount below the cost-based ceiling rate, it will offer the same discount to similarly-situated unaffiliated customers.

As filed, the FERC stated that it was concerned that Detroit Edison may have an incentive to transact in ways harmful to its captive ratepayers. Thus, the FERC conditioned its acceptance of the tariff on Detroit Edison's commitments: (1) "to sell power to DTE Energy Trading only at a rate that is no lower than the rate it charges non-affiliates," (2) "with respect to any power it offered to its affiliates, Detroit Edison must make the same offer to unaffiliated entities at the same time through its electronic bulletin board," and (3) Detroit Edison must simultaneously post the actual price charged to DTE Energy Trading for all transactions.[127]

b. Arms Length Transactions

Generally, the FERC will grant an applicant authority to engage in wholesale sales of power and energy with unaffiliated entities at market-based rates if the applicant and its affiliates do not have, or have adequately mitigated, market power in generation and transmission and cannot erect other barriers to entry.

i. Generation Market Power

In analyzing an applicant's generation market power,[128] the FERC will assess whether the applicant's and its affiliates' market shares of installed and uncommitted capacity exceed levels that the FERC has previously found to be acceptable. However, if an intervenor presents specific allegations of transmission constraints that are relevant to the generation dominance analysis, the FERC will generally only conditionally approve the market-rate tariff and set the issue of generation dominance relative to the alleged transmission constraints for hearing.[129] An applicant may, however, avoid a hearing on this issue by committing not to sell at market rates within areas affected by the

126. *Detroit Edison Co.*, 80 F.E.R.C. ¶ 61,348 (1997).

127. *Id.* at 62,198. A generic market-rate tariff for sales to affiliates is pending before the FERC in *Tucson Elec. Power Co.*, Docket No. ER98-1150.

128. Note that a generation dominance analysis is not needed for authorization to sell at market rates from new generating facilities (i.e., those built after July 9, 1996). *See GS Elec. Generating Coop. Inc.*, 81 F.E.R.C. ¶ 61,042 (1997).

129. *See, e.g., Virginia Elec. Power Co.*, 80 F.E.R.C. ¶ 61,275, at 61,966 (1996); *Consolidated Edison of New World, Inc.*, 78 F.E.R.C. ¶ 61,298 (1997); *Cleveland Elec. Illuminating Co.*, 76 F.E.R.C. ¶ 61,346 (1996); *Plum Street Energy Mktg., Inc.*, 76 F.E.R.C. ¶ 61,319, at 62,554 (1996); *Southern Co. Serv., Inc.*, 75 F.E.R.C. ¶ 61,130, at 62,442, *clarified*, 75 F.E.R.C. ¶ 61,353 (1996); *Wisconsin Public Serv. Corp.*, 75 F.E.R.C. ¶ 61,057, at 61,199 (1996).

transmission constraint.[130]

To define the relevant market for the generation dominance analysis, the FERC relies on the traditional hub-and-spoke methodology. The FERC has rejected arguments that it is inconsistent to rely on a hub-and-spoke analysis for determining generation dominance in the market-based rates context,[131] despite the fact the FERC, in the Merger Policy Statement, stated that the hub-and-spoke methodology has certain drawbacks. The FERC noted that merger applications do not present the same time constraints as do market rate applications, which must be acted on within the sixty-day FPA notice period. Moreover, since merger applications present more significant issues of competitiveness and market power, due to the potential reduction in the number of market participants and the impracticality of undoing a merger once approved, concerns not present in the market rate application context, the FERC concluded that it was neither necessary nor appropriate to change from the traditional hub-and-spoke generation dominance screen.[132]

ii. Transmission Market Power

If the market-rate applicant is a transmission-owning public utility or an affiliate of a transmission-owning public utility, the filing of an open access transmission tariff by the transmission-owning utility is usually sufficient for the FERC to find that transmission market power has been sufficiently mitigated.

iii. Affiliate Abuse/Reciprocal Dealing

The FERC also requires that there be no reciprocal dealing[133] or abuse of affiliate relationships. Interested parties can monitor transactions reported by utilities selling at market-based rates for any reciprocal dealing and can file a complaint alerting the FERC as to any circumstances that may justify the suspension of market-based rate authority. An applicant can generally meet the affiliate abuse requirement by filing a code of conduct governing the interaction of the applicant and its affiliates. This code of conduct must require that any market information the applicant shares with its affiliates be simultaneously disclosed to the public. This requirement extends to "*any* communication concerning the power or transmission business, broker related or not, present or future, positive or negative, concrete or potential, significant or slight."[134]

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130. *Delmarva Power & Light Co.*, 76 F.E.R.C. ¶ 61,331, at 62,582 (1996) (committing in application not to sell power to customers located on the Delmarva peninsula, where it conceded a transmission constraint existed). *See also Florida Power & Light Corp.*, 81 F.E.R.C. ¶ 61,107 (1997); *Florida Power Corp.*, 79 F.E.R.C. ¶ 61,385 (1997).

131. *Arizona Public Serv. Co.*, 79 F.E.R.C. ¶ 61,022 (1997).

132. *See Consolidated Edison of New York, Inc.*, 78 F.E.R.C. ¶ 61,298 (1997).

133. *Atlantic City Elec. Co.*, 75 F.E.R.C. ¶ 61,167 (1996) (no specific filing requirements regarding reciprocal dealing).

134. *Montana Power Co.*, 78 F.E.R.C. ¶ 61,005, at 61,012 (1997). *See also Consolidated Edison of*

There is no need for a code of conduct, however, where the market rate applicant is a cooperative utility unaffiliated with any utility with captive ratepayers. Since a cooperative's ratepayers are also its owners, any profits earned by the cooperative will inure to the benefit of the cooperative's ratepayers.[135] There is also no need for a code of conduct if the utility is not affiliated with a registered holding company and has no affiliates engaged in electric service.[136]

For market rate applicants that are affiliated with a natural gas or oil pipeline or distribution company, the FERC routinely notes that if the market rate applicants or any of their affiliates "deny, delay or require unreasonable terms, conditions, or rates for fuel or services to a potential electric competitor" of the applicants, then the competition may file a complaint with the FERC that could result in a revocation of the applicants' market rate authority.[137]

Market rate applicants must explicitly state separate prices for generation, transmission, and ancillary services in their market rate tariff.[138] This can be accomplished by stating in the tariff that the market rate applicant will file a service agreement pursuant to its open access tariff for any transmission or ancillary services it or its customer needs with respect to power sold under the market rate tariff.[139]

4. Stranded Costs

The FERC set for hearing Duke Power Company's (Duke) request to recover stranded costs as transmission service surcharges in future transmission rates from two departing wholesale requirements customers.[140] The FERC rejected Duke's request to recover stranded costs as exit fees contained in proposed amendments to its existing power sale agreements with its customers. Duke argued it had a reasonable expectation that it would continue to serve the customers and that the $19.4 million it sought to recover was derived from the revenues lost formula in the Open Access Rule and from additional related operational costs.

El Paso Electric Company's (El Paso) franchise agreement with the City of Las Cruces, New Mexico, expired in 1992, and Las Cruces indicated its intention to form a municipal electric utility and purchase power from another supplier. Las Cruces, currently a retail customer of El Paso, subsequently ini-

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New York, Inc., 78 F.E.R.C. ¶ 61,298 (1997) (requiting applicant to amend code where proposed code only applied to "transmission information"); *Unitil Power Corp.*, 80 F.E.R.C. ¶ 61,358 (requiting applicant to amend code where proposed code only applied to "possible wholesale transactions").

135. *See GEN-SYS Energy*, 81 F.E.R.C. ¶ 61,045 (1997); *GS Elec. Generating Coop., Inc.*, 81 F.E.R.C. ¶ 61,042 (1997).

136. *Southern Indiana Gas & Elec. Co.*, 77 F.E.R.C. ¶ 61,024 (1996).

137. *See Commonwealth Elec. Co. and Cambridge Elec. Co.*, 78 F.E.R.C. ¶ 61,191, at 61,813 (1997).

138. *Central Hudson Gas & Elec. Corp.*, 79 F.E.R.C. ¶ 61,390 (1997).

139. *See Commonwealth Elec. Co. and Cambridge Elec. Co.*, 78 F.E.R.C. ¶ 61,191, at 61,813 (1997).

140. *See Duke Power Co.*, 79 F.E.R.C. ¶ 61,161 (1997).

tiated proceedings to condemn and acquire El Paso's distribution facilities in order to form an operating municipal utility system. Unable to reach agreement on the reasonableness of El Paso's stranded cost estimate, Las Cruces requested a determination from the FERC that El Paso had no reasonable expectation that it would continue to serve the city and, therefore, that Las Cruces would not owe stranded costs to El Paso if it purchases power from another supplier using El Paso's transmission system. El Paso disputed Las Cruces's claim, arguing that it had a reasonable expectation to continue serving Las Cruces at retail. The FERC set the issue for hearing.[141]

At the request of the City of Alma, Michigan (Alma), the FERC set for hearing the issue of whether Consumers Energy Company (Consumers) may recover stranded costs from Alma, an existing retail customer that will become a competitor and wholesale customer when it constructs a municipal electric system.[142] Alma argued that Consumers will not have the $56.1 million in stranded costs that it claims because Consumers needs new resources to meet its growing load. Consumers, conversely, have argued that it has a reasonable expectation of serving Alma for the next thirty years.

The FERC also rejected a proposed stranded cost surcharge by Central Vermont Public Service Corporation (Central Vermont). Central Vermont had submitted for filing a notice of cancellation of the rate schedule under which it provides wholesale requirements service to its affiliated distribution subsidiary, Connecticut Valley Electric Company (Connecticut Valley). Connecticut Valley had been directed by the New Hampshire Public Utilities Commission to terminate its wholesale contract with Central Vermont as part of New Hampshire's retail open access plan for the state. Central Vermont proposed to add a stranded cost surcharge to its open access transmission tariff for deliveries of power over its transmission system to retail customers in the service area of Connecticut Valley. Because Central Vermont did not propose to assign stranded costs directly to Connecticut Valley, but rather to its retail customers, the FERC ruled that Central Vermont's filing did not qualify as an appropriate stranded costs recovery proposal. Instead, the FERC stated it would allow a wholesale supplier to seek to recover stranded wholesale costs either through an exit fee amendment to the requirements contract or through rates for wholesale transmission services to a departing wholesale requirements customer that obtains power from a new generation supplier through the use of the utility's open access transmission tariff.

The FERC also rejected Central Vermont's alternative request that the FERC approve the stranded cost recovery proposal by treating this case as one with cost-shifting potential arising in a multi-state context or as one involving a utility restructuring. The FERC noted however, that since the parties contemplated termination of Connecticut Valley's contract prior to its expiration date, Central Vermont could make a filing to amend the contract

141. *See City of Las Cruces, New Mexico*, 80 F.E.R.C. ¶ 61,160 (1997).

142. *See City of Alma, Michigan*, 80 F.E.R.C. ¶ 61,265 (1997).

and include an exit fee.[143]

5. Reliability

Reliability issues have received increased attention in the past year. Among the more notable developments are:

- The Department of Energy's Reliability Task Force issued a series of interim reports concluding that the authority of the FERC over reliability should be expanded and that a self-regulating reliability organization with the authority to enforce mandatory compliance is needed.
- The President's Council on Critical Infrastructure Protection recommended a new federal structure to anticipate and respond to various types of attacks, including "cyber attacks," on all of the nation's infrastructure, including electric utilities.
- NARUC adopted a resolution calling on Congress to authorize states to form voluntary regional bodies with broad authority over issues such as transmission sitting.
- The North American Electric Reliability Council issued its "Blue Ribbon Panel Report" recommending a federally sanctioned and overseen, self-regulating entity with authority over reliability and the continued need for regional reliability organizations.
- The Western Systems Coordinating Council adopted the concept of a regional reliability organization with broad representation from all segments of system users. The organization would derive its authority by contracts among all system users, filed as tariffs at the FERC.
- Members of the New York Power Pool proposed the first statewide reliability organization, the New York State Reliability Council (NYSRC), to address reliability issues that are of special concern in New York. The ISO will implement and enforce rules created by the NYSRC.
- Three pieces of legislation were introduced this past year that have possible impacts on reliability. In the first proposed bill, the FERC would have authority to establish national electric reliability standards and could establish national and regional reliability councils whose reliability recommendations the FERC could adopt.[144] The second proposed bill would establish ISOs to operate portions of the national grid, and vest the FERC with authority to oversee ISOs and ensure transmission reliability.[145] The third proposed bill would establish a national electric reliability council under FERC oversight which would establish reliability standards and have the ability to enforce those standards.[146]

143. *See Central Vermont Public Serv. Corp.*, 81 F.E.R.C. ¶ 61,336 (1997).

144. Federal Power Act Amendments of 1997, S. 1276, 105th Cong. (1997).

145. Transition to Electric Competition Act of 1997, S. 1401, 105th Cong. (1997).

146. Public Utility Holding Co. Act Modernization, H.R. 1960, 105th Cong. (1997).

B. Congress

The First Session of the 106th Congress witnessed many hearings, speeches, and bill introductions addressing the restructuring of the electricity industry, but little movement toward enactment of legislation.

Only one bill was acted on by a legislative committee, and this occurred in the Senate. The "Public Utility Holding Company Act of 1997" would repeal the provisions of the 1935 Public Utilities Holding Company Act (PUHCA) and replace them with a far less restrictive regulatory scheme applicable to utility holding companies.[147] More specifically, this bill would do away with the restraints on geographic and product diversification contained in PUHCA, while clarifying and enhancing the authorities of federal and state regulators to gain access to information about the activities of affiliates of electric and natural gas public utilities.

In the House, Representative Dan Schaefer re-introduced the electricity restructuring legislation he had introduced in the previous Congress.[148] This legislation is intended to provide all customers with a choice of suppliers by no later than the end of the year 2000. The bill does not force states to adopt retail access programs, but provides them an opportunity to do so which, if not taken, triggers a requirement imposed on the FERC to establish and implement such retail access. Among the other provisions of the legislation is one which requires sellers of electricity to meet a portfolio standard for generation of renewable energy.

Another piece of legislation introduced in this Congress would require the states to implement retail access programs and would prohibit utilities from recovering costs rendered uneconomic by the introduction of competition. Other proposed legislation would not impose a customer choice mandate upon the states, but instead would allow utilities to make the decision on providing open access and reward them with certain deregulation benefits, including repeal of PUHCA, if they choose to do so.

C. The States--Legislation, Regulatory Actions, Stranded Costs, Restrictions on Utility Affiliates[149]

1. California

California continued to be at the forefront of electricity restructuring in 1997. However, the California Public Utilities Commission (CPUC) delayed implementation of electric competition in the state from the originally anticipated date of January 1, 1998, to no later than March 31, 1998,[150] due to problems in implementing new software systems. The FERC ruled that the California restructuring should not take effect until "all of the necessary fea-

147. Public Utility Holding Act of 1997, S. 621, 105th Cong. (1997).

148. Electric Consumers' Power to Choose Act of 1997, H.R. 655, 105th Cong. (1997).

149. *See also* EDISON ELECTRIC INST., RETAIL WHEELING & RESTRUCTURING REPORT (Norman Jenks ed., 1997).

150. *Opinion Modifying Various Decisions,* No. 97-12-131 (Cal. P.U.C. 1997).

tures are in place to ensure reliable grid operations . . . [and there has been] . . . sufficient pre-operational testing."[151]

The CPUC approved utility plans to allow consumers direct access to other power providers and issued plans for introducing competition into the provision of billing and metering. The CPUC also determined that utilities and their affiliates should be treated as separate corporate entities and keep separate books and records.

The CPUC also established rules for the recovery of transition and uneconomic costs. Under these rules, above-market costs related to generation, such as generation plants, nuclear settlements, and QF contracts, will be recovered through a "competition transition charge" (CTC) in effect through the year 2001. Costs associated with power purchase contracts, including QF contracts in place as of December 20, 1995, will be collected for the duration of the contract. Employee-related transition costs will be covered by the CTC through 2006.

In an additional effort to facilitate the transition to competition and allow customer savings during the transition cost recovery period, the CPUC approved the rate reduction bond applications of the three major investor owned utilities.[152] The bond issuance should allow a ten percent cut in total electric bills for the 1998-2001 transition cost recovery period. The bonds, which will be retired in 2008, will be repaid by assessing an additional charge on residential and small business customer bills of less than two cents per kWh beginning in 2002.

2. Illinois

On December 16, 1997, Governor Jim Edgar signed into law a bill restructuring the state's electric utility industry and providing most residential customers with a fifteen percent rate reduction beginning August 1, 1998, and an additional reduction of five percent on May 1, 2002.[153] The new restructuring law also introduces a competitive electricity market on May 1, 2002, under which all electricity purchasers in the state will be allowed to choose their supplier. The new law provides for recovery of stranded costs through a transition charge mechanism. That mechanism is available through the end of 2006, but can be extended for up to an additional two years for utilities that still have unrecovered stranded costs after 2006.

3. Maine

Maine mandated retail competition as a matter of state energy policy

151. *Pacific Gas & Elec. Co., San Diego Gas & Elec. Co. and Southern California Edison Co.*, 81 F.E.R.C. ¶ 61,122, at 61,435 (1997).

152. *In the Matter of the Application of the Pacific Gas & Elec. Co.*, 180 P.U.R. 4th 88 (Cal. P.U.C. 1997); *In the Matter of the Application of the Southern California Edison Co.*, Decision No. 97-09-056 (Cal. P.U.C. 1997); *In the Matter of the Application of the San Diego Gas & Elec.*, Decision No. 97-09-057 (Cal. P.U.C. 1997).

153. Elec. Serv. Customer Choice and Rate Relief Law of 1997, 1997 Ill. Legis. Serv. 90-561 (West).

through its enactment of comprehensive restructuring legislation in May.[154] Customer choice will begin on March 1, 2000, and the larger investor-owned utilities must divest all of their generation assets and purchased power contracts by then. The Maine Yankee nuclear power plant must be divested by January 1, 2009. The distribution utilities, Central Maine Power and Bangor Hydro-Electric, must connect the distribution service customers in their service areas but they cannot sell power to them at retail.[155]

4. Maryland

The Maryland Public Service Commission (PSC) decided that retail competition should be phased in beginning in April 1999.[156] The timetable provides for one-third of each rate schedule's load to choose its electricity supplier by July 1, 2000, progressing to two-thirds by July 1, 2001, and full open access by July 1, 2002.[157] The PSC stated that it will provide Maryland utilities with a fair opportunity to recover their verifiable and prudently incurred stranded costs subject to full mitigation.

5. Massachusetts

Governor Paul Cellucci signed a new electric restructuring bill that would implement retail access in March of 1998.[158] The new law also gives state ratepayers a ten percent reduction on their electricity bills on March 1, 1998. It would lock in that cost reduction for a seven-year period and provide for an additional five percent reduction on September 1, 1999. The new law allows recovery of 100 percent of utility stranded costs. These costs are recoverable over a ten-year transition period provided that the costs were incurred prior to March 15, 1995. Massachusetts utilities will be allowed to recover 100 percent of their stranded costs through securitization only if they divest their non-nuclear plants or transfer them to an affiliate. The new statute also requires all Massachusetts electric utilities that have not previously filed restructuring plans to do so.

6. Michigan

The Michigan Public Service Commission has ordered the state's utilities to make available to all customer classes incremental blocks of 2.5% of direct access capacity annually from January 1, 1998, through January 1, 2001. All remaining customers will have customer choice as of January 1, 2002.

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154. H.R. 1274, 118th Leg., 1st Spec. Sess. (Me. 1997).

155. Maine Public Service is exempt from many of the law's restructuring provisions.

156. *Re Provision and Regulation of Electric Service,* Order No. 73834, 181 P.U.R. 4th 185 (Md. P.S.C. 1997).

157. *Re Provision and Regulation of Electric Service*, Order No. 73901, 182 P.U.R. 4th 198 (Md. P.S.C. 1997).

158. Act of Nov. 25, 1997, ch. 164, 1997 Mass. Legis. Serv. 164 (West).

7. Montana

In 1997, a comprehensive restructuring statute was enacted that allows large customers (with a load of greater than 1000 kW) to have retail choice beginning on July 1, 1998. Smaller customers can either aggregate their loads (provided that their demand is in excess of 300 kW) or participate in a pilot starting on the same date.[159]

8. Nevada

Nevada's Public Utility Commission (PUC) is to begin the introduction of retail competition on December 31, 1999, for any electricity-related services found to be "potentially competitive." The restructuring law does not mandate a specific phase-in schedule.[160] It does, however, authorize the PUC to order divestiture and provides for the licensing of alternative sellers and full stranded cost recovery for the costs that the PUC determines to be recoverable.

9. New Hampshire

The New Hampshire Public Utility Commission (PUC) released its final plan for restructuring the state's electric industry which adhered generally to the preliminary PUC restructuring plan.[161] The original target date for full retail competition, January 1, 1998, has now slipped to July 1, 1998.

The most controversial feature of the plan is the PUC's decision to limit recovery of utility stranded costs by means of a benchmark based on average electric rates for New England utilities. The stranded cost limitation would disallow approximately forty percent of stranded costs expected to be incurred by New Hampshire utilities. Generation plants with "negative stranded costs," i.e., with value in excess of book value, would be netted against other plants to derive total stranded cost for a utility.

The stranded cost recovery limitations of the plan provoked an immediate reaction from Public Service Company of New Hampshire (PSNH), the state's largest utility. PSNH sued in U.S. District Court in Rhode Island to enjoin the PUC's application of the new stranded cost provisions. PSNH obtained the requested injunction, which was subsequently broadened to clarify the enforceability of a 1989 agreement between New Hampshire and Northeast Utilities, PSNH's parent.[162] Efforts to resolve this litigation through mediation were unsuccessful. The district court's assertion of jurisdiction and injunction are now pending on appeal before the U.S. Court of Appeals for the First Circuit.

159. S.B 390, 55th Leg., Reg. Sess. (Mont. 1997).

160. A.B. 366, 69th Leg., Reg. Sess. (Nev. 1997).

161. *Re Restructuring New Hampshire's Electric Utility Industry*, Order No. 22,514, 175 P.U.R. 4th 193 (N.H.P.U.C. 1997).

162. *Public Serv. Co. of New Hampshire v. Patch*, N.H. Action No. CA97-121L (D. N.H. June 12, 1997).

10. New Jersey

The New Jersey Board of Public Utilities' (Board) restructuring plan calls for a phase-in of retail competition beginning in October 1998, with full retail choice by July 2000, the opportunity to recover stranded costs by means of a four to eight year market transition charge, and rate reductions in the range of five to ten percent. Pursuant to the plan, each electric utility submitted a rate unbundling filing, a stranded cost filing, and a restructuring filing on July 15, 1997.

11. New York

The New York Public Service Commission (NYPSC) continued to press forward with its own restructuring program. On May 16, 1996, the NYPSC issued an order to introduce retail competition in the state, proposing that retail wheeling be made available to all customer classes by 1998.[163] The order required all of the state's utilities (except Niagara Mohawk, which began its restructuring plan before issuance of the NYPSC's order) to file restructuring plans addressing, among other issues, the details of how best to implement retail wheeling. During this past year, the NYPSC, individual utilities, and customers negotiated the terms of the individual restructuring plans.

12. Oklahoma

Oklahoma enacted its Electric Restructuring Act of 1997, which ensures that direct access by retail consumers is implemented by July 1, 2002. The start date for retail access will be deferred if a more uniform state tax structure has not been adopted by then.

13. Oregon

The House Committee on Power Deregulation introduced a bill which addressed electric utility restructuring.[164] However, the bill was not forwarded to the floor prior to the end of the legislative session. If enacted, the bill would have allowed all Oregonians to choose electricity suppliers by the year 2000. The bill has been recast and will be debated when the legislature meets again in 1999.[165]

The Oregon Public Utility Commission also opened a docket to examine how a utility's stranded costs should be calculated.[166] A final order in this docket is expected in early 1998.

14. Rhode Island

The Utility Restructuring Act of 1996 (the URA) provides for the

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163. *Opinion and Order Regarding Competitive Opportunities for Elec. Serv.*, N.Y.P.S.C. Opinion No. 96-12 (May 20, 1996).

164. H.B. 2821, 69th Leg., Reg. Sess. (Or. 1997).

165. H.B. 2747, 69th Leg., Reg. Sess. (Or. 1997).

166. *Re Investigation of Transition Costs for Electric Utilities,* Docket No. UM 834, Order No. 97-042 (Or. P.U.C. 1997).

phasing in of retail open access in Rhode Island under a three-step process beginning on July 1, 1997. The FERC has approved settlements involving New England Power Company and Montaup Electric Company implementing the URA.

II. STRUCTURAL CHANGE IN THE INDUSTRY

A. *Mergers*

1. Generally

Since the Merger Policy Statement,[167] the FERC has cleared its backlog of merger cases, issuing fifteen final orders in 1997 and a major clarification of the scope of its FPA section 203 jurisdiction.[168] The FERC approved all but one of the proposed mergers, though it conditioned several mergers upon acceptance of various market power mitigation remedies. Applicants accepted the FERC's conditions in some cases,[169] while others terminated their merger proceedings[170] or later collapsed under subsequent state orders.[171]

In its Merger Policy Statement, the FERC promised that those merger applications passing the Competitive Analysis Screen laid out in Appendix A would be reviewed on a fast track with no hearing and a final order ordinarily within five months.[172] Other cases would be reviewed on a regular track with a final order ordinarily within twelve to fifteen months. So far the FERC has met its timelines. Nine of the fifteen cases were decided on a fast track in five months or less, while the six other cases took between seven and nineteen months.[173] The two cases taking longer than fifteen months both began well before the Merger Policy Statement.

The FERC has suggested an extra fast track for dispositions of power

167. *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, 3 F.E.R.C. STATS. & REGS. ¶ 31,044 (1966), *recons. denied*, Order No. 592-A, 79 F.E.R.C. ¶ 61,321 (1997) [hereinafter Merger Policy Statement].

168. 16 U.S.C. § 824b (1994).

169. *San Diego Gas & Elec. Co. & Enova Energy, Inc.*, 79 F.E.R.C. ¶ 61,372 (1997) (merging Enova Corporation and its subsidiary San Diego Gas and Electric Company with Pacific Enterprises and its subsidiary Southern California Gas Company) [hereinafter *Sempra*]; *Ohio Edison Co., Pennsylvania Power Co., Cleveland Elec. Illuminating Co., and Toledo Edison Co.*, 81 F.E.R.C. ¶ 61,110 (1997), *reh'g pending* [hereinafter *First Energy*]; *IES Utilities, Inc., Wisconsin Power & Light Co., South Beloit Water, Gas & Elec. Co., Heartland Energy Service, and Industrial Energy Applications, Inc.*, Opinion No. 419, 81 F.E.R.C. ¶ 61,187 (1997), *reh'g denied*, 82 F.E.R.C. ¶ 61,089 (1998) [hereinafter *IEC*].

170. *Wisconsin Elec. Power Co., Northern States Power Co. (Minn.), Northern States Power Co.(Wis.) & Cinergy, Inc.*, 79 F.E.R.C. ¶ 61,158 (1997) (terminated after remand to the Presiding Administrative Law Judge for further consideration) [hereinafter *Primergy*].

171. *Baltimore Gas & Elec. Co. & Potomac Elec. Power Co.*, 79 F.E.R.C. ¶ 61,027 (1997); *1997 Ends in Merger Bang, Two Whimpers*, THE ELECTRICITY DAILY (Jan. 5, 1997).

172. *Merger Policy Statement*, 3 F.E.R.C. STATS. & REGS. ¶ 31,044, at 30,127.

173. Turnaround time is measured from the date of the applicants' last amendment to their merger application to the date of the final order.

marketer jurisdictional facilities and for mergers of entities not in a jurisdictional business but owning jurisdictional subsidiaries.[174] Such mergers could use an abbreviated or no Appendix A Competitive Analysis Screen and may not require the usual sixty day intervenor comment period. However, requests for expedited action must be fully supported and should discuss "how long it took from the time the contract was signed until the date of filing with the FERC."[175]

A "completed" application supplying the data required by Appendix A speeds the FERC's analysis,[176] but Appendix A does not specify all the data required. The Merger Policy Statement recognized the problem and promised a further rulemaking on filing requirements.[177] That rulemaking has not yet been issued, but it is expected soon.

2. Jurisdiction

This past year the FERC announced a major clarification of its merger jurisdiction.[178] Regardless of the form of the corporate rearrangement, the FERC will now assert FPA section 203 jurisdiction whenever direct or indirect control over a public utility and its jurisdiction facilities is transferred from one company to another. Thus, in *Enova,* a merger between two holding companies that were not public utilities still required FERC approval, because the merger resulted in the transfer of the jurisdictional facilities of Enova subsidiaries, San Diego Gas & Electric Company and Enova Energy (a power marketer), to a new holding company. The FERC made it clear that FPA section 203 jurisdiction also attaches to the transfer of paper facilities alone, such as the books and records and wholesale power sale contracts of a power marketing subsidiary.[179]

3. Effect on Horizontal Competition

Horizontal market power issues are posed by a merger's concentration of power supply in a relevant market.[180] The Merger Policy Statement

174. *Enova Corp.*, 79 F.E.R.C. at 61,496-97 (1997) (commenting that such cases "may be amenable to expeditious action"). *See also Morgan Stanley Capital Group, Inc.*, 79 F.E.R.C. ¶ 61,109 (1997) (approving the merger of Morgan Stanley with Dean Witter in slightly more than one month).

175. *Enova Corp.*, 79 F.E.R.C. ¶ 61,107, at 61,497.

176. *Duke Power Co.*, 79 at 62,037 (1997) (applicants' Appendix A analysis facilitated our expedited processing); *Merger Policy Statement*, 3 F.E.R.C. STATS. & REGS. ¶ 31,044, at 30,127.

177. *Merger Policy Statement*, 3 F.E.R.C. STATS. & REGS. ¶ 31,044, at 30,111 n.3.

178. *Enova Corp.*, 79 F.E.R.C. ¶ 61,107 (1997) (hereinafter *Enova*); *NorAm Energy Serv., Inc.*, 78 F.E.R.C. ¶ 61,108 (1997), *reh'g pending*; *Morgan Stanley Capital Group, Inc.*, 79 F.E.R.C. ¶ 61,109 (1997).

179. *Noram Energy Serv., Inc.*, 79 F.E.R.C. at 61,500 (1997) (merging holding company NorAm Energy and its affiliate NorAm Energy Serv., Inc. with holding company Houston Industries and its subsidiary Houston Lighting & Power Company). *See also Portland General Elec. Co.*, 81 F.E.R.C. ¶ 61,374 (1997) (asserting FPA section 203 jurisdiction over the transfer of related purchase and sales contracts from one subsidiary to another). Where there are no physical or paper jurisdictional facilities involved, the FERC has no jurisdiction.

180. When a merger partner lacks control over any generation or when the merger is between subsidiaries, there is no concentration of supply and thus no need for a horizontal market analysis.

adopted the market power analysis of the Department of Justice Federal Trade Commission Horizontal Merger Guidelines.[181]

Intervenors have suggested a variety of market power mitigation conditions, but proposals for generation divestiture, stranded cost waivers, prohibitions of applicant dynamic scheduling, and contract open seasons have been rejected by the FERC for failure to show a nexus between the remedy requested and harm done by the merger.[182] The FERC's position on requiring applicant participation in an ISO arrangement, however, appears to have evolved from rejecting it as a condition for the merger[183] to accepting it as an applicant commitment with a broad remedial power.[184]

So far the FERC has consistently refused to involve itself in retail rate issues, specifically refusing to consider the merger's effect on retail competition or rates.[185] In addition, the FERC left for state determination the effect of consolidating gas and electric territories and the possible dumping of expensive gas supplies on the captive customers of an electric utility merger partner.[186] However the FERC advised in dicta, that "as retail markets evolve into regional power markets, it may become more difficult for individual states adequately to examine a merger's impact on such markets."[187]

Ordinarily, the FERC dismisses transmission market power concentration issues by observing that the applicants' open access transmission tariffs (OATTs) fully mitigate any such market power.[188] In three cases, however, applicant control over a physically limited transmission interface could not be mitigated by OATTs. Both the *Primergy* and the *IES* cases concerned the Wisconsin Upper Michigan Systems (WUMS) interface connecting the MAPP and MAIN reliability areas. In *IES*, the FERC emphasized that, with two of the three applicants not economically competing in the WUMS subregion, the FERC's competitive concern was with IES's use of enhanced

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Long Island Lighting Co., 80 F.E.R.C. ¶ 61,035, at 61,075 (1997), *reh'g pending* (Brooklyn Union controlled no electric generation); *Cleveland Elec. Illuminating Co.*, 77 F.E.R.C. ¶ 61,032 (1997) (merger of subsidiaries).

181. U.S. Department of Justice and Federal Trade Commission, *Horizontal Merger Guidelines*, 57 Fed. Reg. 41,552 (1992), *revised*, U.S. Department of Justice and Federal Trade Commission, Revision to Horizontal Merger Guidelines (issued April 8, 1997) (available at <http:gopher.usdoj.govatr guidelinessec4.htm>).

182. *E.g., Enron Corp.*, 78 F.E.R.C. ¶ 61,179, at 61,737 (1997) (rejecting divestiture condition); *Union Elec. Co.*, 81 F.E.R.C. ¶ 61,011 (1997) (rejecting open season for Soyland's transmission service agreement).

183. *Cleveland Elec. Illuminating Co.*, 77 F.E.R.C. ¶ 61,032, at 61,127 (1997).

184. *IES Utilities, Inc.*, 81 F.E.R.C. ¶ 61,187, at 61,829-30 (1997); *Ohio Edison Co.*, 81 F.E.R.C. ¶ 61,110, at 61,408 (1997) (participation in an ISO would help). *See also Wisconsin Elec. Power Co.*, 79 F.E.R.C. ¶ 61,158, at 61,727-37 (1997) (rejecting the applicants' proposed, company-specific, not truly independent ISO as sufficient remediation and proposing specific corrections).

185. *Baltimore Gas and Elec. Co.*, 79 F.E.R.C. ¶ 61,027, at 61,114-16 (1997); *Atlantic City Elec. Co.*, 81 F.E.R.C. ¶ 61,173, at 61,754-55 (1997).

186. *San Diego Gas & Elec. Co.*, 79 F.E.R.C. ¶ 61,372, at 62,566 (1997).

187. *Atlantic City Elec. Co.*, 81 F.E.R.C. ¶ 61,173, at 61,755 (1997).

188. *See, e.g., Duke Power Co.*, 79 F.E.R.C. ¶ 61,236, at 62,038. *See also Cincinnati Gas & Elec. Co.*, 80 F.E.R.C. ¶ 61,374 (1997) (deferring merger condition requiring construction of 345 kV line between CG&E and PSI because of OATTs and no regional need).

control over the interface to cut off access of WUMS subregion competitors to power outside of WUMS.[189] Likewise, in *Public Service Company of Colorado*[190] the FERC's concern was with the ability of the merged non-interconnected utilities to maintain the transmission constraint on the western side of Southwest Public Service (SPS), cutting off access of SPS competitors to power from the west. In *IES* and *PSC of Colorado,* the applicants agreed to market power mitigation conditions that provided for joint participation in transmission upgrades and guaranteed access. The FERC's suggested conditions were not acceptable to the applicants in *Primergy.*

4. Effect on Vertical Competition (Convergence Mergers)

In its Merger Policy Statement, the FERC acknowledged that it needed to articulate standards for mergers between electric utilities and natural gas companies, known as vertical or convergence mergers.[191] In its first two vertical merger cases, the FERC laid out its concerns with the incentive of a merged company to restrict gas transportation to electricity generators competing with its electric utility partner, but found no cause for concern since there were sufficient alternative gas suppliers to competing generators.[192]

In three other vertical merger cases with less significant competitive concerns, the FERC added to its vertical market power analysis. In *Destec Energy, Inc.*,[193] the FERC analyzed upstream competitive conditions in two upstream markets, delivered gas and wellhead gas (gas reserves, gathering facilities, and production area pipelines), and how those markets affected four geographically scattered downstream markets where NGC Corporation and Destec Energy, Inc. both owned generation facilities. The wellhead gas market posed no competitive concerns because the market had already been recognized as workably competitive in Order Nos. 436 and 636.[194] The delivered gas market posed no problems due to the many alternative gas suppliers and the lack of contractual control of pipeline capacity. Thus, the FERC did not analyze the downstream electricity market and summarily approved

189. *IES Utilities, Inc.*, 81 F.E.R.C. ¶ 61,187, at 61,828 (1997), *reh'g denied,* 82 F.E.R.C. ¶ 61,089 (1998).

190. 78 F.E.R.C. ¶ 61,267 (1997) (merging Public Service Company of Colorado with Southwestern Public Service Company).

191. *Merger Policy Statement*, 3 F.E.R.C. STATS. & REGS at 30,113.

192. *Duke Power Co.*, 79 F.E.R.C. ¶ 61,236 (1997) (merging Duke Power Company and PanEnergy Corporation); *Enron Corp.*, 78 F.E.R.C. ¶ 61,179 (1997) (merging holding company Enron Corporation and its power marketing affiliate Enron Power Marketing, Inc. with holding company Portland General Corporation and its electric and gas utility subsidiary Portland General Electric Company).

193. 79 F.E.R.C. ¶ 61,373 (1997) (merging Destec Energy, an independent power producer, with NGC Corporation, a holding company for two natural gas pipeline companies, a power marketer, and other subsidiaries).

194. *See Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, Order No. 436, [1982-1985 Transfer Binder] F.E.R.C. STATS. & REGS. ¶ 30,665, at 31,470 (1985); *Pipeline Serv. Obligations and Revisions to Regulations Governing Self-Implementing Transportation; and Regulation of Natural Gas Pipelines After Wellhead Decontrol*, Order No. 636, [1992-1996 Transfer Binder] F.E.R.C. STATS. & REGS. ¶ 30,939, at 30,396 (1992).

the merger without conditions. In *Long Island Lighting Co.,*[195] the FERC considered the merger of a natural gas local distribution company with an electric and gas utility where neither the gas nor electricity service territories overlapped. The FERC summarily approved the merger. Finally, in *PG&E Corp.,*[196] the FERC considered the merger of a power marketing subsidiary of a natural gas holding company with a gas and electric utility. Again, the FERC summarily approved the merger.

5. Effect on Rates

The Merger Policy Statement replaced an analysis of the cost and benefits of a merger with a requirement that applicants negotiate direct wholesale ratepayer protections from merger-related harms such as a rate increase moratorium, or a contract open season. In *Union Electric Company,*[197] the FERC reversed an initial decision that considered the issue of certain contract customers stuck paying more than tariff customers to be a "hybrid issue" requiring an evaluation of the merger's savings. The FERC held that the hybrid analysis improperly revived a cost-benefit analysis of mergers.[198] In *Primergy*, the FERC clarified that rate increase moratoriums are only rate caps that do not prohibit rate decreases,[199] while in *Duke Power Company,* the FERC echoed its Merger Policy Statement, in dicta, that rate increase moratoriums may not provide enough protection if a rate decrease is justified.[200]

6. Effect on Regulation

Where a merger results in a registered holding company, utilities must agree to abide by the FERC's policies concerning intra-corporate transactions for non-power goods and services.[201] The requirement does not apply where the merged company will be an exempt holding company.[202]

Where a state can regulate a merger, or at least has not told the FERC that it cannot so regulate, the FERC finds that the merger has no adverse

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195. 80 F.E.R.C. ¶ 61,035 (1997) (merging Long Island Lighting Company and Brooklyn Union Gas Company).

196. 80 F.E.R.C. ¶ 61,041 (1997) (merging holding company PG&E Corporation and its Pacific Gas Electric Company subsidiary, among others, with holding company Valero Energy Corporation, and its natural gas pipeline subsidiary, Valero Natural Gas Company, along with an indirect power marketing subsidiary).

197. 81 F.E.R.C. ¶ 61,011, at 61,065-66 (1997).

198. *See also Wisconsin Elec. Power Co.,* 79 F.E.R.C. ¶ 61,198, at 61,740 (1997) (refusing to examine merger savings).

199. *Id.* at 61,739.

200. 79 F.E.R.C. ¶ 61,236, at 62,040 (1997).

201. *See, e.g., Public Serv. Co. of Colorado,* 78 F.E.R.C. ¶ 61,267, at 62,139 (1997).

202. *See, e.g., San Diego Gas & Elec. Co.,* 79 F.E.R.C. ¶ 61,372, at 62,566-67 (1997). *But see Ohio Edison Co.,* 80 F.E.R.C. ¶ 61,039, at 61,098-99 (1997) (requiring applicant commitment to FERC policies on intra-corporate transfers on grounds that the SEC has not yet ruled and may not rule that applicants are exempt), *reh'g pending.*

effect on state regulation[203] and will not defer its action until after a state acts.[204] Also, a merger's diminution of state ratemaking authority by transferring state oversight to the FERC is not a valid objection to the merger when the state can regulate the merger.[205]

B. Independent System Operators

1. California

Under the directives of state enabling legislation,[206] California and the stakeholders involved in the negotiation process have elected to create a non-profit public benefit corporation, the California Independent System Operator Corporation (ISO) to run the transmission system, and a second, separate corporation to conduct a daily energy auction, the California Power Exchange Corporation (PX).

The ISO is to provide all eligible customers open and non-discriminatory access to the ISO Controlled Grid, which are the facilities that Participating Transmission Owners (PTOs) turn over to the control of the ISO. All access to the ISO Controlled Grid will be through Scheduling Coordinators, which are the only entities allowed to schedule with the ISO. This feature is designed to permit retail direct access and allow the ISO a manageable number of scheduling entities.

The PX will administer a day-ahead and hour-ahead auction of energy by accepting bids from suppliers and purchasers, including demand-side bids. The PX tariff also provides procedures for it to deal with overgeneration conditions that can exist during periods of low demand and requires that the PX make itself available to forward bids for ancillary services to the ISO. The PX will also forward adjustment bids to the ISO, which the ISO will use to manage congestion. The PX will calculate market-clearing prices based on an iterative set of bids. The PX also is authorized to conduct an auction for ancillary services for those Market Participants that wish to self-supply ancillary services for PX energy.

The initial filings of the ISO and PX tariffs generated a substantial volume of initial and reply comments. The FERC, perceiving that the filed tariffs were the subject of ongoing negotiation and evolution, directed the stakeholders to "put down their pens" and submit revised tariffs that reflected all revised proposals.[207] In response to the ISO's and PX's revised tariffs, the FERC provided interim and conditional authority for the corporations to commence operations, under certain conditions and subject to future studies and reporting by the ISO and PX.[208] With respect to the governance of both the ISO and the PX, the FERC accepted the general

203. *See, e.g., San Diego Gas & Elec.*, 79 F.E.R.C. at 62,567 (1997).

204. *Enron Corp.*, 78 F.E.R.C. ¶ 61,179, at 61,740 (1997).

205. *Wisconsin Elec. Power Co.*, 79 F.E.R.C. ¶ 61,158, at 61,740-41 (1997).

206. AB 1890, 1996 Portion of 1995-96 Reg. Sess. (Cal. 1996).

207. *Pacific Gas & Elec. Co.*, 80 F.E.R.C. ¶ 61,128 (1997).

208. *Pacific Gas & Elec. Co.*, 81 F.E.R.C. ¶ 61,122 (1997).

principle of governance by stakeholder boards as they were proposed. However, the FERC rejected, as inconsistent with its jurisdiction, a role for a state-created Oversight Board that was proposed to have a continuing function in the appointments of Governors to the ISO and PX Boards and some review of ISO decisions. The FERC also rejected the proposal to allow ISO and PX employees to own limited shares of the stock of Market Participants.

In late December 1997, the ISO and PX announced that the need to test their data processing systems and provide additional training to their staffs required that they postpone commencement of operations until no later than March 31, 1998. The FERC directed that both entities provide fifteen days advance notice before operations are set to commence.[209]

2. PJM

The FERC conditionally approved a proposal by nine of the ten members of the Pennsylvania-New Jersey-Maryland Interconnection (PJM) to restructure the PJM Power Pool and establish an ISO.[210] The FERC approved a "two tier" governance structure under which an independent seven member Board of Managers (PJM Board) would be responsible for supervision and oversight of the day-to-day operations of the PJM Power Pool. A Members Committee, consisting of five sectors representing generation owners, other suppliers, transmission owners, electric distribution and end-use customers, would elect and provide advice to the PJM Board.

The FERC accepted the proposed zonal rate design, subject to its being replaced by a regional system-wide rate design methodology within five years. The FERC also accepted the proposed locational marginal pricing (LMP) methodology for recovery of transmission congestion costs, but acknowledged that the lack of price certainty is a limitation of LMP. To address this concern, the ISO was directed to initiate a process for the development of a congestion pricing proposal that provides greater price certainty.

The FERC also questioned whether PJM's historical practice of withholding firm transmission interface capability as a substitute for installed generating reserves is consistent with its open-access policies. Contradicting its own recent precedents,[211] the FERC ordered that all existing bilateral transmission service and bundled wholesale power agreements be modified to eliminate the potential for incurrence of multiple (pancaked) transmission service charges within the PJM control area.

3. NEPOOL

The thirty-third amendment to the New England Power Pool

209. *Id.*

210. *Pennsylvania-New Jersey-Maryland Interconnection*, 81 F.E.R.C. ¶ 61,257 (1997).

211. Order No. 888, at 31,664; Order No. 888-A, at 30,190-92; Order No. 888-B, at 62,088; *Pacific Gas and Elec. Co.*, 81 F.E.R.C. ¶ 61,122 (1997); *Wisconsin Elec. Power Co.*, 79 F.E.R.C. ¶ 61,158 (1997).

(NEPOOL) Agreement effected a comprehensive restructuring of NEPOOL through, in part, an amendment to transfer control of the region's transmission grid and generation operation to an ISO. NEPOOL filed a supplement to the Agreement providing for interim arrangements crucial to planning for regional needs during the 1997 summer period. The FERC conditionally accepted the agreement on an interim basis and required NEPOOL to comply with eleven conditions with respect to the establishment of the ISO.[212] The FERC presented these conditions as FERC ISO Principles, which seek mainly to ensure fairness, reliability and efficiency in the management of the ISO and the independence of its operations from the owners of the transmission grid. Later in 1997, NEPOOL filed the thirty-fourth agreement to meet those eleven conditions and asked for authorization of market-based rates for power sold by its members.[213]

4. NYPP

The proposed restructuring of the New York Power Pool (NYPP), pending before the FERC,[214] presents certain matters of generic interest, including locational marginal pricing (LMP) of transmission congestion and the formation of three new institutions—an ISO, the New York Power Exchange, and the New York State Reliability Council (Council).[215] NYPP's LMP approach is similar to a proposal approved in the PJM restructuring proceeding.[216]

NYPP's ISO governance structure is based to a large extent on the NEPOOL governance proposal approved by the FERC.[217] NYPP proposes that the ISO's Board of Directors be comprised of ten members, none of which will have any affiliation with any market participant.

NYPP's plan to form an ISO and related market institutions differs from other electric restructuring proposals in that a separate body, the Council, would be created to establish bulk power system reliability rules and monitor the ISO's compliance with those rules. The proposed Council would be governed by a thirteen-member Executive Committee consisting of representatives from each of the eight NYPP member transmission providers, one representative each from non-utility generators, large industrial and commercial customers, and municipal electric systems, respectively, and two representatives who are not affiliated with any market participant.

212. *See New England Power Pool Agreement*, 79 F.E.R.C. ¶ 61,374 (1997).

213. These filings are pending before the FERC.

214. *See Central Hudson Gas & Elec. Corp.*, Nos. ER97-1523-000 and OA97-470-000. (Several parties, including certain power marketers, independent power producers, cooperative and municipal customers, electricity consumers, and the New York Public Service Commission, have either protested NYPP's restructuring filing or supported modifications to the proposal).

215. In a related matter, NYPP submitted a proposal for market-based pricing of bulk power sales. *See Central Hudson Gas & Elec. Corp.*, No. ER97-4234-000.

216. *Pennsylvania-New Jersey-Maryland Interconnection*, 81 F.E.R.C. ¶ 61,257 (1997).

217. *New England Power Pool*, 79 F.E.R.C. ¶ 61,374 (1997).

5. Midwest

Initially envisioned as spanning eleven states and 90,000 miles of transmission lines, the Midwest ISO appears to be back on the drawing board as utilities consider whether a geographically smaller, less diverse ISO would make more sense. In December 1997, concerns were raised by a majority of the original members that inclusion of the American Electric Power system would make development of an ISO too difficult. Members questioned whether such a large ISO was needed, especially in light of the pace and scope of restructuring efforts. American Electric Power continues to support a geographically large ISO, believing it will increase reliability and simplify pricing.

6. Pacific Northwest

After over a year of planning, the Pacific Northwest Rockies ISO (IndeGO) looked as if it would be ready for filing at the FERC by the late summer of 1997. But no consensus was reached as more questions were raised regarding cross utility rate subsidies, the significant cost of the system relative to any potential benefits, and whether the Bonneville Power Administration (BPA) should or can legally join. In addition to the questions raised about the BPA, at least one of the original signatories to the plan to develop an ISO has dropped out and another has indicated that it is considering it due to concerns about the impact on retail customers.

Public support seems to be building for an Independent Grid Scheduler (IGS) which would manage scheduling for the coordinated system but would not be responsible for reliability and dispatch. These functions would continue to be handled by the member utilities and the WSCC. How the FERC might view an IGS or IndeGO is unclear,[218] but in the Northwest there is strong sentiment that the system worked well in the past, access was available, and that the ISO concept does nothing to improve the system reliability, scheduling, and dispatch.

C. Federal PMAs

Issues related to the federal power program continue to be a topic of discussion in Congress. A bill to abolish the United States Department of Energy and transfer the United States Power Marketing Administration (PMAs) to the U.S. Army Corps of Engineers, pending a final decision on their status, was introduced.[219] Legislation outlining plans to privatize the Western Area Power Administration, Southeastern Power Administration and the Southwestern Power Administration, was also introduced.[220] Other legislation introduced would require the U.S. Army Corps of Engineers and

218. Of the three ISO proposals that the FERC has reviewed--California, NEPOOL and PJM--none were accepted as filed because they did not sufficiently address the eleven standards of Order No. 888. Neither IndeGO nor the IGS concept meets all eleven standards.

219. S. 236, 105th Cong. (1997).

220. H.R. 296, 105th Cong. (1997); H.R. 718, 105th Cong. (1997); H.R. 1577, 105th Cong. (1997).

the Bureau of Reclamation to outsource maintenance and improvement work on the generating units at federal dams to the highest bidder.[221] Successful bidders would receive a percentage of the energy resulting from the projected increase in the output of electricity from the projects.

1. Bonneville Power Administration

In the House, two PMA privatization bills contained Bonneville Power Administration (BPA)-related provisions which called for privatizing the BPA[222] and transferring responsibility over BPA to the U.S. Department of Interior.[223] In the Senate, a bill was introduced that would: (1) apply the FERC's transmission rules to transmission service provided by the BPA; (2) direct the FERC to develop a transition stranded-cost recovery mechanism that assures no undue risk for the United States Treasury or bondholders of securities backed by the BPA; (3) enable the BPA to use proceeds from the sale of any renewable energy credit to repay its debt to the United States Treasury and Washington Public Power Supply system bondholders, and; (4) assure the BPA participation in a FERC-approved and regulated ISO in the Pacific Northwest.[224] Two other significant proposals related to the BPA were unveiled shortly before Congress adjourned for the year, but not introduced, which address concerns related to the future viability of the BPA, and provide a comprehensive restructuring proposal. Both proposals would authorize the BPA to participate under certain conditions in a FERC-approved and regulated ISO in the Pacific Northwest.

2. Tennessee Valley Authority

There were important changes on the appropriations front for the Tennessee Valley Authority (TVA) in 1997. The TVA requested that Congress eliminate the TVA's $100 million annual federal appropriations for non-power programs, and shift those activities to another arm of the federal government. While legislators from the TVA region expressed serious concerns about the plan, Congressional appropriators still reduced TVA's fiscal year 1998 funding to $70 million, and called for an elimination of such funding in fiscal year 1999.

Meanwhile, significant legislative proposals related to TVA are pending in Congress. One proposal would require TVA and its distributors to become subject to wholesale and retail competition on January 1, 2002.[225] This bill would also allow TVA to compete in wholesale electricity markets outside its region. Other proposals include allowing potential competitors to compete against TVA within its territory, while keeping TVA's sales within its existing region, and establishing a twelve-member commission appointed

221. H.R. 2968, 105th Cong. (1997).
222. H.R. 718, 105th Cong. (1997).
223. H.R. 1577, 105th Cong. (1997).
224. S. 1301, 105th Cong. (1997).
225. *Id.*

by the President to study TVA operations and assess its future role.[226]

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226. H.R. 2082, 105th Cong. (1997).