

# The Energy Policy Act of 1992—A Watershed for Competition in the Wholesale Power Market

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*Recent trends in the electricity generation market have spawned interest in substituting competition for traditional regulatory controls. To this end, Congress adopted regulatory reforms in the Energy Policy Act of 1992 aimed at stimulating competition in electricity generation. Most notably, the new legislation authorizes federal regulators to open transmission lines to competing generators of electric power. In addition, the Act frees a class of wholesale power generators from burdensome holding company regulation. In this Article, Messrs. Watkiss and Smith analyze the procompetitive reforms in the 1992 Act, and attempt to predict their impact on the electric utility industry. In the short run, at least, the Act will foster greater competition among power generators. The Act, however, leaves many critical decisions to federal and state regulators; their decisions on how to implement the new law will determine whether a vigorously competitive wholesale power market develops as Congress intended.*

Introduction .....	449
I. Evolution of the Electricity Generation Market .....	450
II. Electricity Title of Energy Policy Act of 1992 .....	456
A. Transmission Access .....	456
1. Transmission Access Before the Energy Policy Act .....	456
2. New FERC Authority to Order Transmission Access .....	459
a. Scope of FERC Authority .....	460
b. Issuance of Wheeling Orders .....	461

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c.	<i>Modifying or Terminating Wheeling Orders</i>	462
d.	<i>Rates for Wheeling Service</i>	463
B.	<i>Exempt Wholesale Generators</i>	464
1.	<i>Industry Structure Prior to Energy Policy Act</i>	465
2.	<i>New Class of Exempt Wholesale Generators</i>	467
a.	<i>Benefits of EWG Status</i>	467
b.	<i>EWG Eligibility</i>	468
c.	<i>Special Cases—"Spin-Offs" and "Hybrids"</i>	470
d.	<i>Ownership of EWGs by Registered Holding Companies</i>	471
3.	<i>Restrictions on EWG Transactions</i>	471
a.	<i>Affiliate Transactions</i>	471
b.	<i>Affiliate Preference or Advantage</i>	472
c.	<i>Retail Sales</i>	472
C.	<i>Foreign Utility Ownership</i>	473
D.	<i>PURPA Amendments on State Consideration of Wholesale Power Market Issues</i>	475
III.	<i>Issues to be Addressed by Federal and State Regulators</i>	476
A.	<i>Implementing Transmission Access</i>	477
1.	<i>Setting Rates for Wheeling Service</i>	477
a.	<i>Embedded Cost Versus Incremental Cost Debate</i>	477
b.	<i>Moving to Mileage-Based Rate Design</i>	478
c.	<i>Determining Who Gets Paid</i>	480
2.	<i>Modifying or Terminating Wheeling Orders</i>	481
a.	<i>Good Faith Effort to Enlarge System</i>	481
b.	<i>Termination of Transmission Orders</i>	482
B.	<i>Planning and Coordinating Transmission Systems</i>	482
1.	<i>Consensus RTG Proposal</i>	483
2.	<i>Role of States</i>	484
3.	<i>Role of FERC</i>	485
C.	<i>EWG and Purchased Power Issues</i>	485
1.	<i>Market-Based Rates for Wholesale Power</i>	486
a.	<i>Transmission as a Prerequisite</i>	487
b.	<i>Prerequisite Protections Against Abuse of Affiliation</i>	488
c.	<i>Need to Monitor Market Power</i>	489
2.	<i>State Evaluations of Purchased Power</i>	490
	<i>Conclusion</i>	491

## Introduction

The Energy Policy Act of 1992 (EPAc)<sup>1</sup> fundamentally changes federal regulation of the electric utility industry,<sup>2</sup> greatly facilitating the development of a competitive market for wholesale electric power.<sup>3</sup>

Title VII (the Electricity Title) of the EPAc amends the Federal Power Act (FPA)<sup>4</sup> to empower the Federal Energy Regulatory Commission (FERC) to issue orders requiring owners of power transmission lines to “wheel”<sup>5</sup> power for others—generators and purchasers of wholesale power—at just and reasonable rates. This change is designed to open the highways of electricity commerce, which until now have been accessible almost exclusively to transmission-owning electric utilities.

The Electricity Title also eliminates Public Utility Holding Company Act (PUHCA)<sup>6</sup> regulation of certain wholesale electric power generators—entities exclusively in the business of owning or operating (or both) facilities used to generate power for sale exclusively at wholesale or leased to a public utility. These new PUHCA-exempt generators are called “exempt wholesale generators” (EWGs). This change empowers non-utility wholesale power generators to compete free of the structural and financial regulations designed for utility companies possessing franchise retail monopolies.

These changes portend increased competition in wholesale power markets. Moreover, the EPAc may prove to be the watershed event leading to a restructured U.S. power market in which the traditional utility functions—electricity generation, transmission, and distribution—become increas-

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1. Pub. L. No. 102-486, 106 Stat. 2776 (1992).

2. The electric utility industry is one of the nation's largest industries. The gross stock of fixed private capital in the investor-owned electric utility industry (excluding cooperatives and publicly-owned systems) was \$931.2 billion in 1991. BUREAU OF ECONOMIC ANALYSIS, U.S. DEP'T OF COMMERCE, SURVEY OF CURRENT BUSINESS (Aug. 1992).

3. President Bush described the Electricity Title of the EPAc as “a landmark . . . furthering competition in the way electricity is generated and sold, thus lowering prices while ensuring adequate supplies.” President's Statement on the Energy Policy Act, White House Release, 28 WEEKLY COMP. PRES. DOC. 2094 (Oct. 24, 1992).

4. 16 U.S.C. §§ 791a-825u (1988). The Federal Power Act provides for federal regulation of wholesale, interstate electricity services and transactions. Regulation of retail sales of electric energy is reserved to the states. *Id.* § 824(a),(b).

5. While wheeling is a form of electricity transmission, it is ordinarily distinguished from the transmission service that a utility provides when it transmits power that it generates or purchases to its own retail customers. By contrast, wheeling is the “transfer by direct transmission or displacement [of] electric power from one utility [or other power seller] to another [utility] over the facilities of an intermediate utility.” *Otter Tail Power Co. v. United States*, 410 U.S. 366, 368 (1973).

6. 15 U.S.C. §§ 79 to 79z-6 (1988).

ingly separated, with only transmission and distribution continuing to be operated and regulated exclusively as a natural monopoly.<sup>7</sup>

Part I reviews the evolution of the market for generation, beginning with the enactment of the federal laws regulating electric utilities in the 1930s, the emergence of non-utility generators as a result of the enactment of the Public Utilities Regulatory Policy Act (PURPA) in 1978, the increasing competition in the wholesale power market of the 1980s, and the constraints imposed on this trend toward competition by the 1930s laws. Part II reviews the changes made by the EPAct: the new authority given to FERC to order utilities to provide transmission service at fair rates; the exemption of wholesale power generators from PUHCA regulation; the near-complete easing of PUHCA regulation on the ownership of foreign utilities; and the directions to states to consider wholesale power market issues under PURPA. Part III analyzes a number of important issues that will be faced by federal and state regulators as they implement this new statutory regime, including designing rates for transmission services, coordinated planning and operation of interconnected transmission systems, and oversight of wholesale power markets. Finally, we offer recommendations on how regulators can most effectively implement the new law and best achieve its goal of increased competition.

## I. Evolution of the Electricity Generation Market

The structure of today's electric power industry derives largely from the expansion and consolidation of private holding company empires in the first three decades of this century, followed by PUHCA's divestiture requirements and subsequent regulation of the holding companies since 1935. By 1932, three holding companies—the Electric Bond & Share Company, J.P. Morgan's United Corporation, and the Insull Group—controlled almost half of the nation's investor-owned utilities, and 67% of privately generated electric power came from only eight holding company systems.<sup>8</sup>

In that same year, James Bonbright and Gardner Means summarized the impact of the holding companies:

[T]he public utility holding company has been a great factor in the development of efficient electrical systems throughout the country . .

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7. See generally PAUL L. JOSKOW & RICHARD SCHMALENSEE, *MARKETS FOR POWER: AN ANALYSIS OF ELECTRIC UTILITY DEREGULATION* (1985); see also Paul L. Joskow & Richard Schmalensee, *Incentive Regulation of Electric Utilities*, 4 *YALE J. ON REG.* 1 (1986); W. Berry, *The Case for Competition in the Electric Utility Industry*, *PUB. UTIL. FORT.*, Sept. 16, 1982, at 14.

8. See D.W. Hawes & W.S. Lamb, *Restructuring under PUHCA: Can the '35 Act Envelope Be Stretched?*, 5 *ELEC. J.* 18 (June 1990); see also U.S. SECURITIES AND EXCHANGE COMM'N, *STATEMENT CONCERNING PROPOSALS TO AMEND OR REPEAL THE PUBLIC UTILITY HOLDING COMPANY ACT OF 1935* (June 2, 1982).

. . . [Yet] its almost complete freedom from regulation has become a major public menace. . . . The time has come when a lower premium should be paid for speed of development and a much higher premium for carefully evolved plans of coordination dictated in the interests of engineering efficiency . . . rather than primarily in the interest of large profits for utility financiers.<sup>9</sup>

Throughout the 1920s and early 1930s, the abuses of the holding company structure included excessively leveraged capital structures at the holding company level, abusive internal pricing between subsidiaries (i.e., self-dealing at the expense of ratepayers), and pyramidal ownership structures that deceived investors and defied regulation.<sup>10</sup>

Responding to popular sentiment that the unbridled growth of utility holding companies had “given tyrannical power and exclusive opportunity to a favored few,”<sup>11</sup> President Franklin Roosevelt proposed, and Congress enacted, the Public Utility Act of 1935, which included both PUHCA (originally the Wheeler-Rayburn Act) and the utility regulatory scheme of the FPA.<sup>12</sup>

The structural requirements of PUHCA and the jurisdictional provisions of the FPA remained essentially unchanged from 1935 to 1978.<sup>13</sup> During this period, most significant electric utilities were vertically integrated—they generated power, transmitted power within their service territory, and distributed power to their retail customers. Utilities, the largest of which are predominantly investor-owned,<sup>14</sup> met increasing demand by constructing new generating

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9. J. BONBRIGHT & G. MEANS, *THE HOLDING COMPANY: ITS PUBLIC SIGNIFICANCE AND ITS REGULATION* 221-22 (1932).

10. See FEDERAL TRADE COMM’N, *UTILITY CORPORATIONS*, S. DOC. NO. 92, 70th Cong., 1st Sess., pt. 73-A (1928); P. Wells, *Public Regulation of the Holding Company in Public Utilities*, 1926 PROCEEDINGS OF THE ACADEMY OF POLITICAL SCIENCE. For example, one subsidiary of the Insull Group, Midwest Utilities, “had 111 subsidiaries of its own.” Leonard S. Greenberger, *The PUHCA: Busting the Trusts*, PUB. UTIL. FORT., Mar. 15, 1991, at 19, 21 [hereinafter *Busting the Trusts*].

11. MESSAGE FROM THE PRESIDENT OF THE UNITED STATES, H.R. DOC. NO. 137, 74th Cong., 1st Sess. 2 (1935) (transmitting to the Congress “Report of the National Power Policy Committee With Respect to the Treatment of Holding Companies”). A “none too benevolent private paternalism” is how President Roosevelt described the holding company empires of 1935. *Id.* at 2.

12. 16 U.S.C. § 791a-825(u) (1988). The FPA was enacted as part of the Public Utility Act of 1935. 49 Stat. 803, 847.

13. In 1976, one commentator observed:

[T]he Holding Company Act . . . is the only one in the whole SEC series that has not had a comma changed so far as I know from the day of enactment until this moment, even though the SEC has managed to restructure a whole gigantic industry. It is a tremendous tribute to those who drafted these statutes, particularly this statute of 1935.

Louis Loss, *52nd Annual Meeting of the American Law Institute*, 1975 A.L.I. PROC. 490 (1976).

14. Private, profit-making electric companies serve approximately 75% of the nation’s electric consumers. Approximately 15% of all consumers receive electric power from public power systems—utilities owned by the taxpayers of a city, district, or other public area and operated as a function of the government. About 1,000 rural electric non-profit cooperatives serve the remaining 10% of consumers. See generally AMERICAN PUBLIC POWER ASSOCIATION, *PUBLIC POWER FACTS* (1992). These cooperatives are non-profit entities owned and managed by their users. NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION, *RURAL ELECTRIC SOURCEBOOK* 128 (1990).

capacity. Technological innovation and economies of scale held the price of electric service relatively constant (and declining in real terms) until the 1970s.<sup>15</sup>

The power market received two major shocks in the 1970s—the energy crisis and the environmental movement. The OPEC oil embargoes drove up the price of oil, hence driving up utility fuel costs. Electricity demand grew less rapidly than expected as prices jumped, leaving utilities with over-ambitious construction programs. At the same time, environmental protests, litigation, cost overruns, double-digit inflation, and regulatory action brought construction of many new nuclear power stations to a virtual halt. Under intense consumer pressure, regulators proved increasingly unwilling to approve rate increases needed to recover spiraling costs of new generating capacity.<sup>16</sup>

Utilities increasingly perceived a breakdown in the “regulatory compact” under which utilities had come to believe they were entitled to recover fully all of their utility investments plus a return on equity. No longer was it a “foregone conclusion that a franchise utility, with an obligation to serve, would build its own new generating capacity.”<sup>17</sup> Buying power (from other utilities or non-utility generators) rather than building generating capacity—and thereby shifting rather than shouldering construction and operating risk—became an option considered favorably by an increasing number of utilities.

In 1978, Congress gave competition in the power generation market a largely unintended boost. The Public Utilities Regulatory Policies Act of 1978 (PURPA)<sup>18</sup> conferred upon certain non-utility generators called qualifying facilities (QFs)—a narrowly circumscribed class of non-utility power wholesalers<sup>19</sup> that are either cogenerators<sup>20</sup> or small power producers using specified energy sources<sup>21</sup>—special regulatory treatment in order to promote energy

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15. See generally Regulations Governing Independent Power Producers, IV F.E.R.C. ¶ 32,456, at 32,105-06 (Mar. 16, 1988) [hereinafter IPP Proposal].

16. See *id.* (citing Oakridge National Laboratory, Prudence Issues Affecting the U.S. Electricity Industry (July 1987) (unpublished draft)); *Idaho Power Stock Slumps after PUC Denies Equity Return on Valmy-2 Share*, ELEC. UTIL. WK., July 26, 1986, at 11.

17. C.A. Falcone, Electric Utility Consultants, Inc., Emerging Trends in Electric Power, Electric Systems Planning and Operations Conference 6 (Nov. 5-6, 1992) (unpublished manuscript, on file with the *Yale Journal on Regulation*).

18. Pub. L. No. 95-617, 92 Stat. 3117 (codified as amended at 16 U.S.C. §§ 2601-2645 (1988)).

19. Not more than 50% of the equity in a QF may be held by a concern “primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities.)” 18 C.F.R. § 292.206(a) (1992).

20. Cogeneration is the simultaneous production of electric energy plus steam, heat, or some other useful form of energy. To qualify, a cogeneration facility must comply with certain conditions, including thermal efficiency requirements, established by FERC. See 16 U.S.C. § 796 (1988).

21. Permissible primary energy sources are biomass, waste, geothermal, and any renewable source such as solar and wind. 16 U.S.C. § 796(17)(A)(i) (1989). Fossil fuels may not constitute more than 25% of energy input. 18 C.F.R. § 292.204(b) (1992). Until recently the maximum capacity for small power production was 80 megawatts, but this size limitation was removed in 1990. See Pub. L. No. 101-575, 104 Stat. 2834 (1990); Pub. L. No. 102-46, 105 Stat. 249 (1991) (codified as amended at 16 U.S.C. § 796(17)(E)).

efficiency and environmentally-preferable generation technologies. PURPA created a market for cogeneration and renewable power by requiring utilities to purchase the power generated by QFs at the purchasing utility's "incremental cost . . . of alternative electric energy,"<sup>22</sup> i.e., the purchaser's avoided cost to generate or purchase the same amount of electricity.<sup>23</sup> Moreover, PURPA provided that ownership of a QF would not trigger burdensome PUHCA regulation.<sup>24</sup>

Congress intended these changes to promote conservation of power resources and reduced reliance on oil, but not competition in wholesale power markets.<sup>25</sup> Nonetheless, PURPA spawned new non-utility competitors in the power generation industry. Before PURPA, a non-utility generator was faced with trying to sell power to the local utility, a disinterested monopsony. The non-utility generator could not sell directly to retail customers because it did not have a state retail franchise, and could not deliver power to other wholesale customers—i.e., other utilities—because the local utility controlled and restricted the transmission facilities necessary to reach those buyers. The local utility could simply decline to buy the power, offer any price it chose, or refuse to transmit the power to another willing utility purchaser.

PURPA gave QFs leverage. PURPA required the local utility to buy power from QFs and to do so at a fair price.<sup>26</sup> In markets where the utility's cost of building new capacity or purchasing power was high, its avoided cost was

22. 16 U.S.C. § 824a-3(b) (1988); 18 C.F.R. §§ 292.303(a),(d), 292.304(b),(e) (1992).

23. Avoided cost may include both energy and capacity costs. Energy costs are the variable costs associated with production of a unit of electricity. Capacity costs are the costs associated with providing the capability to meet demand—generating facilities, demand management investments, or firm power purchase contracts. Capacity payments must be made to a qualifying facility "when, and only when, the purchase or construction of capacity will be avoided by the purchasing electric utility as a result of its purchase of QF power." Administrative Determination of Full Avoided Costs, Sales of Power to Qualifying Facilities, and Interconnection Facilities, IV F.E.R.C. ¶ 32,457 at 32,158 (March 16, 1988) [hereinafter Avoided Costs]. FERC explained avoided cost pricing under PURPA as follows:

The essence of avoided cost pricing is that payments to the QF should reflect the payments that would have been made to the sources of power that were displaced by the QF, that is, the costs avoided by purchasing QF power. Avoided cost pricing encourages efficiency and innovation, because QFs get any difference between their own costs and the avoided cost rate. The utility's ratepayers are indifferent in the short run because the utility pays no more for the QF's power than it would pay for generating its own power or purchasing power from another source.

*Id.* at 32,163 (footnote omitted). Implementation of avoided cost pricing is in most instances done by the states, under delegation from FERC. 18 C.F.R. § 292.401 (1992); see Regulations Governing Bidding Programs, IV F.E.R.C. ¶ 32,455 at 32,024 (March 16, 1988) [hereinafter Bidding Rule]. Certain state programs implementing avoided cost pricing have been criticized as seeking to promote policies other than QF power, with the result of setting avoided cost either too high or too low. Avoided Cost, *supra*, at 32,163.

24. 16 U.S.C. § 824a-3(e) (1988); 18 C.F.R. § 292.602(b) (1992) (excluding QFs from definition of "electric utility company"). QFs are also exempt from certain provisions of the FPA, *id.* § 292.601, and state law or regulation. *Id.* § 292.602(c).

25. See H.R. REP. NO. 543, 95th Cong., 2d Sess. 5-6, 8 (1978); see also American Paper Inst. v. American Elec. Power Serv. Corp., 461 U.S. 402, 417-18 ("basic purpose . . . to increase utilization of cogeneration and small power production facilities and to reduce reliance on fossil fuels").

26. See *supra* note 23 and accompanying text.

ordinarily also high; consequently, the economic incentives in such markets to build QFs were often substantial. QFs have proved to be aggressive competitors; in recent years, they have accounted for more than half of new generation capacity brought on line in the United States.<sup>27</sup>

Emergence of a competitive generation market has been evidenced by increasing state regulatory interest in competitive bidding. Many states now require utilities to seek competitive bids for meeting new power needs, in lieu of the traditional practice of simply having the utility build capacity to meet expanding demand.<sup>28</sup> The utility seeking new capacity typically will send out a request for proposals, and will receive bids from utilities, QFs, and possibly other non-utility generators. It will then compare the bids received with the costs of its own capacity expansion options. The utility and its ratepayers get the benefit of new capacity at the lowest reasonable cost. This trend toward competitive bidding was driven in part by the perception that a competitive market, rather than administrative fiat, would more accurately establish the avoided cost for purposes of setting rates for QF-generated power.<sup>29</sup>

In summary, the confluence of three trends—proliferation of QF power in the 1980s,<sup>30</sup> increasing regulatory disallowance of utility investment in generating (particularly large nuclear) plants in the 1970s and 1980s, and the successes of state experiments in competitive bidding—strengthened the perception that wholesale power competition, in lieu of PUHCA regulation, could effectively discipline wholesale power markets.<sup>31</sup>

However, there were still major obstacles to competition in the market for long-term generating capacity and associated energy. First, without fair transmission access, the competitiveness of the wholesale power market would

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27. The percentage of new U.S. generation capacity accounted for by QFs was 53% in 1990, 50% in 1991, and 62% in 1992. JEAN-LOUIS POINIER, MARKET OUTLOOK: THE 1993 TO YEAR 2000 NUMBERS 1 (1993); National Independent Energy Producers, *The Competitive Power Landscape* (presented to American Public Power Association, May 15, 1992); EDISON ELECTRIC INSTITUTE, 1990 CAPACITY AND GENERATION OF NON-UTILITY SOURCES OF ENERGY (1991).

28. As of May 1991, 36 states had adopted or were in the process of adopting competitive bidding procedures. NATIONAL INDEP. ENERGY PRODUCERS, *COMPETING FOR POWER: A SURVEY ON COMPETITIVE PROCUREMENT SYSTEMS AND BLUEPRINT FOR THE FUTURE 5* (1991) [hereinafter *COMPETING FOR POWER*]; see also U.S. DEP'T OF ENERGY, *ANALYSIS OF OPTIONS TO AMEND THE PUBLIC UTILITY HOLDING COMPANY ACT OF 1935, NATIONAL ENERGY STRATEGY, TECH. ANNEX 1*, at 14-15 (1991/1992); NATIONAL INDEP. ENERGY PRODUCERS, *BIDDING FOR POWER; THE EMERGENCE OF COMPETITIVE BIDDING IN ELECTRIC GENERATION* (Mar. 1990); W.H. Wellford & P.J. Elston, *Why PUHCA Reform is Likely in the 102d Congress*, PUB. UTIL. FORT., Mar. 15, 1991, at 24, 25. Loans that the Rural Electrification Administration provides to rural electric cooperatives are now conditioned on procuring needed capacity through bidding. *COMPETING FOR POWER*, *supra*, at i, 6.

29. See *Bidding Rule*, *supra* note 23, at 32,025-26 ("bidding has the potential for eliminating the seemingly endless debates over what alternative sources of supply are truly avoided").

30. Since 1978, QF's have added 25,000 megawatts of capacity to the nation's wholesale power supply. See *Busting the Trusts*, *supra* note 10, at 22.

31. *E.g.*, 137 CONG. REC. S1512-13 (daily ed. Feb. 5, 1991) (statement of Sen. Johnston on introduction of S. 341). This perception began to be held as early as 1983 when FERC (together with the Rand Corporation) began experimenting with non-cost-of-service pricing of bulk power in certain regional markets. See *Public Serv. Co. of New Mexico*, 25 F.E.R.C. ¶ 61,469 (1983).

necessarily be limited. Transmission service was needed to deliver power from willing sellers to willing buyers. Yet transmission facilities were owned by utilities possessing geographic transmission monopolies; those same utilities were competing with other buyers in purchasing wholesale power and competing for sales with other power sellers. In some cases, transmission monopolies were being abused to stifle competition and give transmission owners an unfair advantage in the wholesale power market.<sup>32</sup>

The second obstacle was PUHCA. Non-utility power developers ineligible for QF status under PURPA found that they needed to use convoluted corporate structures to avoid the burdensome regulation of PUHCA. Although Congress could not have envisioned non-utility power wholesalers in 1935, PUHCA created substantial obstacles to their development in recent years.

In 1990 and 1991, Operations Desert Shield and Desert Storm in the Persian Gulf dramatically increased the currency of energy issues on the national political agenda. During this period, the Bush Administration submitted to the Congress a National Energy Strategy and implementing legislation.<sup>33</sup> With leadership from Senator Bennett Johnston (D-LA), Chairman of the Senate Committee on Energy and Natural Resources, on PUHCA reform, and from Representatives Edward Markey (D-MA), Carlos Moorhead (R-CA), and House Energy and Power Subcommittee Chairman Philip Sharp (D-IN) on transmission access, this omnibus energy legislation ultimately became the vehicle for addressing the obstacles to competition in the electricity industry.

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32. Examples of complete denial of access for anticompetitive reasons include *Otter Tail Power Co. v. United States*, 410 U.S. 366, 373, 377 (1973) (combined refusal to sell power at wholesale or wheel for municipal systems), *aff'g in relevant part*, 331 F. Supp. 54, 62-64 (D. Minn. 1971); *City of Manti, Utah v. Utah Power & Light Co.*, 36 F.E.R.C. ¶ 61,088 at 61,214-15 (1986) (termination of service to city coupled with refusal to wheel power from municipal power agency; subsequently settled); *Northern Indiana Pub. Serv. Co.*, 23 F.E.R.C. ¶ 61,179 at 61,389 (1983) (alleged use of transmission monopoly to maintain anticompetitive control over transmission-dependent customer; subsequently settled); *Pacific Gas & Elec. Co.*, 26 F.E.R.C. ¶ 63,048 at 65,186-87, 65,218, 65,231 (1984) (refusal to allow municipal systems to join power pool coupled with refusal to provide transmission found anticompetitive); *Southeastern Power Admin. v. Kentucky Utils. Co.*, 26 F.E.R.C. ¶ 61,127 at 61,322-23 (1984) (utility's refusal to wheel power administration electricity to municipalities not remediable by FERC because transmission order would not preserve existing competitive relationship); *see generally* CASAZZA, SCHULTZ & ASSOCS., NATIONAL REGULATORY RESEARCH INST., NON-TECHNICAL IMPEDIMENTS TO POWER TRANSFERS: THREE CASE STUDIES OF IMPEDIMENTS TO POWER TRANSFERS 221-30 (K. Kelly, ed., 1987). Access can also be denied *de facto* by discriminatory rates, terms, and conditions. *E.g.*, *Commonwealth Edison Co.*, 34 F.E.R.C. ¶ 61,115 at 61,169 (1986) (utility's effort to prevent city from purchasing electricity from competing supplier by adding unrelated service costs to transmission rate resulted in four-fold price increase); *Consolidated Edison Co. of New York, Inc.—PASNY No. 3.*, Op. No. 86-25 at 8-9 (N.Y. Pub. Serv. Comm'n, Oct. 14, 1986) (rejecting utility's effort to load unrelated costs into transmission rate charged industrial customers); *see also* *Tex-La Electric Cooperative of Texas, Inc.*, Application for an Order Requiring Provision of Transmission Service, FERC Docket No. TX93-1-000 (filed Jan. 19, 1993) (alleging that denial of scheduling service for hydro power amounts to an unlawful denial of transmission under the EPCA).

33. National Energy Strategy Act, H.R. 1301, 102d Cong., 1st Sess. *reprinted in* 137 CONG. REC. H1455 (daily ed. Mar. 6, 1991).

## II. Electricity Title of Energy Policy Act of 1992

The Electricity Title of the EPAAct makes sweeping changes in the federal law affecting the market for electricity generation. The key provisions of the new law—increased transmission access under the FPA, PUHCA exemption for wholesale power generators, PUHCA exemption for foreign utility ownership, and state evaluations of wholesale power purchase issues under PURPA—are described below.

### A. *Transmission Access*

The new law empowers FERC to order any “transmitting utility”<sup>34</sup> to provide wholesale wheeling services whenever the requested transmission can be provided consistent with maintaining reliability and would be in the public interest.

#### 1. *Transmission Access Before the Energy Policy Act*

In 1935, Congress established the Federal Power Commission (FPC) (predecessor of the FERC) and authorized the Commission to regulate the sale for resale of power and the transmission of power in interstate commerce. States retained authority over power plant siting and all aspects of retail distribution.<sup>35</sup> Pursuant to its interstate commerce jurisdiction, the Commission sets rates and charges for power and transmission of power.

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34. The definition of “transmitting utility” is broad. A “‘transmitting utility’ means any electric utility, qualifying cogeneration facility, qualifying small power production facility, or Federal power marketing agency which owns or operates electric power transmission facilities which are used for the sale of electric energy at wholesale.” EPAAct § 726(a) (adding new FPA § 3(23)) (to be codified at 16 U.S.C. § 796(23)). Under the FPA, “‘electric utility’ means any person or State agency which sells electric energy; such term includes the Tennessee Valley Authority, but does not include any Federal power marketing agency.” 16 U.S.C. § 796(22) (1988).

35. *First Iowa Hydro-Elec. Coop. v. FPC*, 328 U.S. 152, 171 (1946); *see* S. REP. NO. 621, 74th Cong., 1st Sess. 18 (1935); H.R. REP. NO. 1318, 74th Cong., 1st Sess. 8 (1935).

The FPA was intended to “fill the gaps” in utility regulation that the U.S. Supreme Court had recognized in a series of cases culminating in *Public Utils. Comm’n v. Attleboro Steam & Elec. Co.*, 273 U.S. 83 (1927). The Court held in *Attleboro* that the Commerce Clause limited state authority over interstate transmission and sales-for-resale of electricity and natural gas. *Id.* at 89-90. In recent years, *Attleboro*’s “bright line rule” has given way to a more flexible analysis that attempts to balance the importance of a state’s interest against the burden imposed on interstate commerce. *See* *Arkansas Elec. Coop., Inc. v. Arkansas Pub. Serv. Comm’n*, 461 U.S. 375, 383-89, 393-95 (1983) (upholding state regulation of wholesale rates of rural electric cooperative because neither FPA nor Rural Electrification Act preempted such regulation). The “bright line” has further been blurred in rulings asserting preemptive federal jurisdiction over investment and allocation decisions of multi-state integrated utility systems. *See, e.g.,* *Mississippi Power & Light Co. v. Mississippi*, 487 U.S. 354, 373-74 (1988); *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953 (1986).

In contrast to the FPA's plenary federal authority over rates and charges for wholesale electricity sales and transmission service, the 1935 FPA provided no federal authority to require transmission owning utilities to wheel power. In *Otter Tail Power Co. v. United States*,<sup>36</sup> the Supreme Court addressed the application of the FPA to an electric utility company's concurrent refusal to sell electric power at wholesale or to wheel electric power to municipal electric power systems in the areas serviced by Otter Tail, an investor-owned public utility. According to the Court, the FPA did not authorize the Federal Power Commission to order wheeling by Otter Tail since "Congress rejected a pervasive regulatory scheme for controlling the interstate distribution of power in favor of voluntary commercial relationships."<sup>37</sup> In short, the FPA provided no federal authority to order mandatory wheeling. Transmission access would be provided, if at all, voluntarily by transmission monopolists or pursuant to authorities other than the FPA.<sup>38</sup>

In 1978, Congress took its first stab at opening up transmission access. That year, the FPA was amended by PURPA to authorize FERC to order any electric utility to interconnect with an applicant<sup>39</sup> and to provide wholesale transmission service (including enlargement of capacity) to the applicant. However, this new authority came with a number of conditions.<sup>40</sup> Section 211(c)(1) of the FPA, as added by PURPA, barred FERC from granting an application for wheeling service "unless the Commission determines that such order would reasonably preserve existing competitive relationships."<sup>41</sup> Interpreting this restriction in a 1984 order, FERC explained:

The statute itself . . . prohibits the issuance of wheeling orders that have a significant procompetitive effect. This subsection provides that even if the order would conserve energy, promote efficiency, or improve

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36. 410 U.S. at 375-76.

37. *Id.* at 374. While the Commission lacked authority under the FPA to order transmission access, the Court itself ordered wheeling under its antitrust jurisdiction to remedy Otter Tail's anticompetitive and monopolistic practices. *Id.* at 376. According to the Court, Otter Tail utilized its "strategic dominance in the transmission of power in most of its service area" to foreclose municipalities from establishing municipally-owned distribution systems rather than continuing to purchase retail power from Otter Tail. The Court held that Otter Tail's refusal to sell power to these municipalities at wholesale or to wheel power from another source violated the "attempt to monopolize" clause of Section 2 of the Sherman Act by destroying threatened competition. *Id.* at 377.

38. Even prior to the Otter Tail decision, some utilities incurred wheeling obligations as part of nuclear plant license conditions imposed by the Nuclear Regulatory Commission (NRC) pursuant to the antitrust provisions of the Atomic Energy Act of 1954, § 105, 42 U.S.C. § 2011 (1988). In approximately 30 of the nearly 100 nuclear plant licensing cases considered in the 1960s and 1970s, the NRC imposed license conditions as a remedy to alleged anticompetitive problems. In many cases, these conditions included wheeling obligations. J. Pfeffer, *Policies Governing Transmission Access and Pricing: The Wheeling Debate Revisited*, PUB. UTIL. FORT., Oct. 31, 1985, at 26, 28.

39. 16 U.S.C. § 824i (1988). PURPA entitled qualifying facilities (other than geothermal producers) to seek interconnection only, but not transmission.

40. *See id.* § 824j.

41. *See id.* § 824j(c).

reliability,<sup>[42]</sup> no order may be issued if existing competitive relationships are not reasonably preserved.<sup>43</sup>

As a consequence of this interpretation, FERC has issued no orders requiring wheeling under section 211. Procompetitive wheeling would have to wait.

Although barred in recent years from issuing pro-competitive transmission access orders, FERC has indirectly used other FPA authority to impose transmission access requirements as the quid pro quo to which a utility must accede in order to obtain some other regulatory authorization or benefit. Under authority of FPA sections 205 and 206,<sup>44</sup> FERC has conditioned authorizations to sell power at market-based, rather than cost-of-service rates, on the selling utilities' agreement to file transmission tariffs.<sup>45</sup> Also, under FPA section 203 authority, FERC has imposed wholesale transmission conditions on certain merger or consolidation applications.<sup>46</sup> FERC's asserted basis for imposing

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42. In addition to preserving existing competitive relationships, the 1978 law required that any wheeling order must not only preserve, but "improve," the reliability of the electric utility system to which the order applies. *Id.* § 824j(a)(2)(C). While wheeling orders ordinarily will not lessen reliability, neither will they ordinarily improve reliability.

43. *Southeastern Power Admin. v. Kentucky Utils. Co.*, 26 F.E.R.C. ¶ 61,127, at 61,323 (1984). As a consequence of this interpretation, FERC's section 211 authority was apparently limited to ordering wheeling to address fuel shortages or to promote coordination of electricity among utilities. *Southeastern Power Admin. v. Kentucky Utils. Co.*, 25 F.E.R.C. ¶ 61,204, at 61,539 (1983); *cf.* *New York Elec. & Gas Corp. v. FERC*, 638 F.2d 388, 402 (2d Cir. 1980) (finding limiting competitive purpose of "facilitating bulk purchases of power"). For criticisms of this narrow construction, see F. Norton & M. Early, *Limitations on the Obligations to Provide Access to Electric Transmission and Distribution Lines*, 5 ENERGY L.J. 47 (1984); R. Pierce, *A Proposal to Deregulate the Market for Bulk Power*, 72 VA. L. REV. 1183, 1189 n. 38 (1986); see also Reiter, *Competition and Access to Bottleneck: The Scope of Contrast Carrier Regulation under the Federal Power and Natural Gas Acts*, 17 LAND & WATER L. REV. 76-77 (1983) ("The PURPA wheeling option, to the extent it was intended to encourage and facilitate transmission access, is so far largely a failure").

44. 16 U.S.C. §§ 824d, 824e (1988).

45. *E.g.*, *Entergy Servs., Inc.*, 58 F.E.R.C. ¶ 61,234, at 61,760-68 (1992) (authority to sell up to 100 MW at negotiated rates authorized together with adoption of transmission service tariffs), *order on reh'g* 60 F.E.R.C. ¶ 61,168 (1992) (affirming ineligibility of certain customers to obtain wheeling); U.S. Dep't of Energy, *Bonneville Power Admin.*, 53 F.E.R.C. ¶ 61,193, at 61,668 (1990) (market-based rates authorized only because accompanied by transmission access commitments to former captive customer); *Public Serv. Co. of Indiana*, Order No. 349, 51 F.E.R.C. ¶ 61,367, at 62,186, 62,190-204 (1990), *reh'g granted in part*, Order No. 349-A, 52 F.E.R.C. ¶ 61,260 (1990) (authorization to sell up to 450 MW to unspecified customers at market-based rates conditioned on system wide access conditions); *Pacific Gas & Elec. Co.*, 46 F.E.R.C. ¶ 61,390 (1989) (market-based rates approved in exchange for transmission access commitments to former captive customer); *Pacific Gas & Elec. Co.*, 42 F.E.R.C. ¶ 61,406 (1988) (market-based rates approved in exchange for transmission access commitments to former captive customer), *modified*, 43 F.E.R.C. ¶ 61,403 (1988); *Pacific Gas & Elec. Co.*, 38 F.E.R.C. ¶ 61,242 (1987) (authorization for experimental market-based rates with strictly voluntary transmission access), *experiment extended*, 47 F.E.R.C. ¶ 61,121 (1989), and 50 F.E.R.C. ¶ 61,339 (1990), *modified*, *Western Sys. Power Pool*, 55 F.E.R.C. ¶ 61,495, at 62,713-14 (1991) (permanent authorization for market-based rates denied, but capped market-based rates allowed to continue); *c.f.*, *United Illuminating Co.*, 60 F.E.R.C. ¶ 61,214, at 61,734 (1992) (declining to impose transmission condition on seller of market-based electricity where seller found not to possess sales on transmission market power or ability to control market entry).

46. *E.g.*, *Montana Power Co.*, 56 F.E.R.C. ¶ 61,296 (1991) (conditioning merger authorization in part on modified transmission access provisions); *Kansas Power & Light Co.*, 56 F.E.R.C. ¶ 61,356 (1991) (transmission access conditions accepted in connection with acquisition settlement); *Utah Power & Light Co.*, 47 F.E.R.C. ¶ 61,209 (1989) (transmission conditions imposed on merger authorization), *remanded*

tariffs as a condition on both mergers/consolidations and on market-based rate authorizations has been that non-discriminatory, competitive access to a utility's transmission monopoly is necessary to mitigate the market power that could result from certain mergers/consolidations<sup>47</sup> or which might be used to exact supra-market prices under the pretense of market-based rates.<sup>48</sup> FERC's ability to impose wholesale transmission requirements under this conditioning authority was not affected by the EPAct.<sup>49</sup>

## 2. New FERC Authority to Order Transmission Access

New FPA section 211 empowers any electric utility (including cooperatives and municipal systems), federal power marketing agency, or any other person generating electric energy for sale for resale (including QFs)<sup>50</sup> to apply to

*on other grounds sub nom. Environmental Action Inc. v. FERC*, 939 F.2d 1057 (D.C. Cir. 1991) (finding inadequate basis for denying QF access and retail wheeling); *cf. UtiliCorp United Inc.*, 56 F.E.R.C. ¶ 61,031 (1991) (order approving acquisition without transmission commitments), *revised*, 56 F.E.R.C. ¶ 61,427 (1991).

47. *E.g.*, *Utah Power & Light Co.*, 45 F.E.R.C. ¶ 61,095, at 61,289-90 (1988), *aff'd in relevant part*, 47 F.E.R.C. ¶ 61,209, at 61,733 (1989) (transmission tariff conditions are fact specific and not generic).

48. *E.g.*, *Public Serv. Co. of Indiana*, 51 F.E.R.C. ¶ 61,367, at 62,223 n.85 (cases cited).

49. A provision in the House bill would have codified and made mandatory FERC's practice of conditioning both merger/consolidation approvals and authorizations to charge market-based rates on a utility filing a generally applicable transmission tariff. Although this provision was not included in the final legislation, its rejection should not be interpreted as a disapproval of FERC's decisional precedents. Rather, omission of the House's mandatory transmission conditions is more accurately viewed as an affirmation of FERC's practice of imposing transmission conditions only in instances where necessary to mitigate undue market power that might result from a merger/consolidation or authorization to sell power at market-based rates. *E.g.*, *Utah Power & Light Co.*, 45 F.E.R.C. ¶ 61,095, at 61,289-90 (1988), *aff'd in relevant part*, 45 F.E.R.C. ¶ 61,209 (1988) (transmission tariff conditions are fact specific and not generic). Notwithstanding this general affirmation, to the extent that FERC's conditioning authority previously could have empowered FERC to impose retail wheeling requirements, the EPAct withdrew that authority. *See infra* notes 54-56 and accompanying text.

50. By making QFs eligible to seek mandatory transmission orders, new FPA § 211 not only expanded the class of those who could petition FERC for mandatory transmission orders, but it also made moot a lingering controversy under existing law concerning FERC's repeated refusals to include QFs among beneficiaries of so-called voluntary transmission obligations that FERC had imposed pursuant to its authority to condition approvals of mergers under FPA § 203 and market-based rates under FPA § 205. *See supra* text accompanying notes 44-49. In connection with its approval of the merger of Utah Power & Light Co. and PacifiCorp, in order to mitigate market power of the merged companies, FERC ordered the merged company to provide transmission to all electric utilities, but not to QFs. *Utah Power & Light Co.*, 45 F.E.R.C. ¶ 61,095, at 61,290 n.158 (1988); *aff'd in relevant part*, *Utah Power & Light Co.*, 47 F.E.R.C. ¶ 61,209, at 61,739-42 (1989). According to FERC, QFs were excluded because § 211 of the FPA, before amended by the EPAct, did not authorize FERC to grant QF transmission requests. *Utah Power & Light Co.*, 47 F.E.R.C. at 61,741; *see also Entergy Servs., Inc.*, 58 F.E.R.C. ¶ 61,234 (1992) (holding QFs ineligible to receive transmission imposed as condition on market-based rates). A careful parsing of these decisions reveals that FERC's position was based on its opposition to giving QFs a means to reach distant utilities and force those utilities to purchase the QF power at avoided cost. On appeal of *Utah Power & Light*, the court extensively criticized FERC's arguments for denying QFs transmission access on a par with utilities and remanded. *Environmental Action, Inc. v. FERC*, 939 F.2d 1057, 1061-62 (D.C. Cir. 1991). On remand, FERC persisted in its argument that QFs were ineligible to seek transmission under the FPA and could only become eligible by waiving QF status (and benefits) and becoming an electric utility. *Utah Power & Light Co.*, 57 F.E.R.C. ¶ 61,363, at 61,188-90 (1992). Not until the EPAct made QFs eligible to seek mandatory transmission orders did FERC abandon its exclusion of QFs. *Utah Power & Light Co.*, 62

FERC for issuance of an order requiring a “transmitting utility”<sup>51</sup> to provide wheeling services, including any enlargement of transmission capacity necessary to provide the service requested by the applicants.<sup>52</sup> FERC, in turn, is authorized to grant the application and order a transmission facility owner to provide the applicant with the requested service on fair terms.<sup>53</sup>

a. *Scope of FERC Authority*

The EPAct authorizes FERC to order a transmitting utility to provide wheeling service to an applicant. In addition to providing access to existing capacity, FERC may compel a transmitting utility to enlarge its transmission capacity where existing capacity is inadequate to provide the requested service.

FERC is prohibited from issuing any order that would require retail wheeling, i.e., wheeling to an ultimate consumer of electricity.<sup>54</sup> FERC also is barred from conditioning any other approval (e.g., approval of mergers, consolidations, or non-cost-based rates) on agreeing to provide retail wheeling.<sup>55</sup> Moreover, the provisions dealing with “sham transactions” bar any order that would indirectly compel retail wheeling.<sup>56</sup>

A transmission order applies only to applicants—FERC is not empowered to require utilities to adopt transmission tariffs of general applicability. The orders will address critical issues including the type of service to be provided (point-to-point, or more flexible grid access), rates charged for transmission service, term of the utility’s obligation to provide service, and conditions and procedures for modifying or terminating service.

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F.E.R.C. ¶ 61,018 (1993).

51. See *supra* note 34.

52. EPAct § 721 (amending FPA § 211(a)) (to be codified at 16 U.S.C. § 824j(a)).

53. *Id.* (amending FPA § 211) (to be codified at 16 U.S.C. § 824j).

54. EPAct § 722(3) (adding § 212(h) to the FPA) (to be codified at 16 U.S.C. § 824k(h)).

55. *Id.* This provision thereby denies FERC any authority under the FPA to condition an order—e.g., an approval of a merger/consolidation under FPA § 203 or of a market-based power rate under FPA §§ 205 or 206—on the provision of retail wheeling. Cf. *Environmental Action, Inc. v. FERC*, 939 F.2d 1057, 1062 (D.C. Cir. 1991) (pre-EPAct decision implying that FERC could condition a merger/consolidation approval on a requirement that the merged or consolidated utilities provide retail wheeling).

56. Industrial consumers, who would be the principal beneficiaries of retail wheeling, opposed stripping FERC of all FPA authority to order retail wheeling. Although they lost that battle, they did succeed in obtaining a savings clause that specifically preserves the authority of state commissions to order retail wheeling. The existence of this savings clause implies that, within its boundaries, a state may possess authority to compel provision of retail wheeling service. Electric utilities and some industry observers have questioned whether states have any authority over transmission that is not preempted by the FPA. See generally I.D. Benkin, *Who Makes the Rules? Federal and State Jurisdiction over Electric Transmission Access*, 13 ENERGY L.J. 45 (1991).

b. *Issuance of Wheeling Orders*

Several conditions qualify FERC's new authority to order utilities to provide wheeling service. Before issuing a wheeling order, FERC must make two affirmative findings. First, the applicant must prove and FERC must find that the requested service would satisfy the traditional public interest standard of the FPA. Second, the applicant must demonstrate and FERC must find that the order would meet the requirements of the amended section 212 of the FPA. As amended, section 212 prescribes rates, terms, and conditions for transmission services,<sup>57</sup> prohibits FERC from ordering transmission to an ultimate consumer—i.e., retail wheeling—and establishes rules applicable to transmission service provided by the Tennessee Valley Authority, federal power marketing agencies, and the Federal Columbia River Transmission System.<sup>58</sup>

In addition to these prerequisite findings, FERC may not issue a transmission order if certain findings are made. First, no wheeling order may be issued if, “after giving consideration to consistently applied regional or national reliability standards, guidelines, or criteria, [FERC] finds that such order would unreasonably impair the continued reliability of electric systems affected by the order.”<sup>59</sup> Second, FERC may not issue an order granting wheeling to an applicant unless the applicant has requested service from the transmitting utility at least 60 days prior to application to FERC.<sup>60</sup> In other words, Congress did not want to have FERC issue an order unless the parties had attempted to work out a deal among themselves beforehand. Inasmuch as the reliability and prior application conditions are both stated in the negative—“no order may be

57. EPAAct § 722(1) (amending FPA § 212(a)) (to be codified at 16 U.S.C. § 824k(a)).

58. *Id.* § 722 (adding new FPA § 212(i),(j)) (to be codified at 16 U.S.C. § 824k(i),(j)). These provisions limit the FERC's authority. As to the Federal Columbia River Transmission System, FERC may order the Administrator of the Bonneville Power Administration to provide transmission, but only to the extent consistent with other applicable laws (including rates). *Id.* (adding new FPA § 212(i)(1)). If other laws preclude the requested transmission or preclude providing such service at rates, terms, and conditions FERC would otherwise require, then the applicant is relieved from providing any similar transmission service to the Administrator. *Id.* (adding new FPA § 212(i)(4)). Because the Tennessee Valley Authority (TVA) is permitted to sell power only within a service territory specified in federal law—i.e., TVA cannot compete beyond that territory—the new law protects TVA by generally prohibiting FERC from ordering TVA to transmit power that will be consumed within TVA's service territory. *Id.* (adding new FPA § 212(j)).

59. *Id.* § 721 (amending FPA § 211(b)) (to be codified at 16 U.S.C. § 824j(b)).

60. *Id.* § 721 (amending FPA § 211(a)) (to be codified at 16 U.S.C. § 824j(a)). The EPAAct also establishes information requirements designed to inform those who might request wheeling service about what transmission capacity exists and how and where it is constrained. *Id.* § 723 (adding § 213 to the FPA) (to be codified at 16 U.S.C. § 824l). If a party has requested wheeling service and the transmitting utility does not agree to provide such service on rates, terms, and conditions acceptable to the requester, the transmitting utility must, within 60 days of receiving the request, provide the requester with a “detailed written explanation” of the basis for its proposed rates and an analysis of any constraints that affect the provision of service. *Id.* Pursuant to this requirement, FERC has proposed new regulations requiring all utilities to file annually with FERC information about potentially available transmission capacity and known constraints. New Reporting Requirement under the Federal Power Act and Changes to Form No. FERC-714; Proposed Rulemaking, 58 Fed. Reg. 17,544 (April 5, 1993).

issued"—they can be viewed as affirmative defenses available to owners of transmission facilities affected by a proposed wheeling order.

FERC's authority is discretionary. Where both affirmative findings have been made and neither negative finding has been established, FERC is authorized, *but not required*, to issue the requested wheeling order. Nonetheless, it is improbable that FERC will exercise its discretion to deny outright a transmission order if all conditions precedent—including the required public interest determination—are satisfied.<sup>61</sup>

*c. Modifying or Terminating Wheeling Orders*

The new law specifies conditions under which wheeling orders, once issued, can be modified or terminated. These "escape hatches" for transmitting utilities were retained from the 1978 amendments. Section 211 of the FPA instructs FERC to terminate or modify any wheeling order if it finds that: (a) due to changed circumstances, the conditions for issuance of the order are no longer met; (b) any capacity used to provide wheeling services under the order that was excess at the time of the order is no longer excess and is needed to serve the utility's own retail customers; or (c) the FERC order required enlargement of transmission capacity in order to provide a service and the transmitting utility has been unable, after making a good faith effort, to obtain the necessary regulatory approvals or property rights.<sup>62</sup>

Nonetheless, FERC may not terminate or modify an order if that order includes terms and conditions agreed to by the parties that either fix the term during which wheeling service will be provided or provide other methods (such as arbitration) for terminating or modifying a wheeling order.<sup>63</sup> Because third-party applicants for transmission orders will be relying on transmission to purchase power needed to serve customers or to fulfill sales contract obligations, unanticipated interruption of transmission service could be disastrous. They will consequently seek to ensure that the conditions for termination or modification are spelled out at the time the transmission order is issued.

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61. FERC is more likely to exercise its discretion to condition a transmission order on the applicant agreeing to certain changes in either how the requested service is provided or the rates and charges to be paid for the service.

62. 16 U.S.C. § 824j(d) (1988). Because no orders have heretofore been issued under section 211 as enacted in 1978, there exists no decisional precedent on these "escape hatches."

63. *Id.* § 824j(d)(3).

d. *Rates for Wheeling Service*

One of the most important, and difficult, policy issues in devising a sensible transmission access policy is how to set rates for wheeling services. If rates are set too high, competing wholesale power generators seeking to get their power to market will be frustrated, transmission-owning utilities will gain unfairly from their transmission monopoly, and consumers will be hurt. If rates are set too low, transmitting utilities and their ratepayers will not receive fair compensation for the use of ratepayer-financed facilities.

The genesis of the transmission pricing provisions of the final bill was nothing short of tortuous, with titanic battles over regulatory policy, economic theory, and even last minute skirmishes concerning the placement of a comma. This legislative battle paralleled a concurrent battle even now being waged in FERC proceedings. The issue in both fora was essentially the same: Should wheeling services be priced at traditional embedded-cost rates, incremental-cost rates, or some combination of both? Whatever the EPA's pricing language does, it did not resolve this fundamental question, leaving the issue to FERC.

The new law contains a number of general directions to FERC on how to set wheeling rates. As amended by the new law, section 212 of the FPA requires FERC to set rates, charges, terms, and conditions for wholesale transmission service that permit the transmitting utility to recover "all the costs incurred in connection with the transmission services and necessary associated services," including "an appropriate share, if any, of legitimate, verifiable and economic costs, including taking into account any benefits to the transmission system of providing the transmission service, and the costs of any enlargement of transmission facilities."<sup>64</sup> Rates shall "promote the economically efficient transmission and generation of electricity,"<sup>65</sup> suggesting incremental pricing. The law also restates several traditional and familiar FPA ratemaking principals: "[R]ates, charges, terms and conditions shall . . . be just and reasonable, and not unduly discriminatory,"<sup>66</sup> and costs should be allocated to those customers that cause costs to be incurred.<sup>67</sup>

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64. EPA § 722 (amending FPA § 212(a)) (to be codified at 16 U.S.C. § 824k(a)).

65. *Id.*

66. *Id.*

67. Specifically, rates and charges are to "ensure that, to the extent practicable, costs incurred in providing [ordered] wholesale transmission services, are recovered from the applicant for such order, and not from a transmitting utility's existing wholesale, retail, and transmission customers." *Id.* Some may argue that this language prescribes transmission rates equal to incremental rather than average embedded cost. As explained *infra* in text accompanying notes 136-40, FERC currently uses a hybrid pricing model based on the higher of incremental or embedded costs for pricing wholesale wheeling services. The generality of Congress' language, however, suggests little more than its acceptance of the longstanding ratemaking tenet that cost allocation should seek to match cost responsibility with cost causation. See generally J.C. BONBRIGHT ET AL., PRINCIPLES OF PUBLIC UTILITY RATES 274-76 (1988).

The threshold question begged by this jumble of ratemaking jargon is whether this pricing provision adds or subtracts anything from the traditional "just and reasonable" standard of the FPA applied by FERC in other ratemaking situations. The conference report suggests that no departure from "just and reasonable" was intended: "Rates, charges, terms and conditions for wholesale transmission services ordered under section 211 in all cases shall be just and reasonable, and not unduly discriminatory or preferential."<sup>68</sup>

The new law neither codifies nor invalidates the wheeling pricing policy emerging from FERC. The House bill would have codified the wheeling pricing guidelines that FERC developed over the last five years,<sup>69</sup> requiring FERC to balance three objectives in setting transmission rates:

- (a) compensate native load customers for legitimate and verifiable economic costs of providing the transmission service;<sup>70</sup>
- (b) provide the lowest reasonable transmission rates for the transmission service; and
- (c) prevent the collection of monopoly rents by the transmitting utility and promote the efficient transmission and generation of electricity.<sup>71</sup>

In the end, the conferees did not include these guidelines in the new law. The enacted pricing provision neither affirms nor rejects FERC's guidelines and rate design formula, leaving FERC considerable latitude to make policy in this area.<sup>72</sup>

## B. *Exempt Wholesale Generators*

Before enactment of Title VII, non-utility developers of electric generating plants had essentially three avenues open to them: (1) develop a PURPA QF,

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68. JOINT EXPLANATORY STATEMENT OF THE COMMITTEE OF CONFERENCE, 138 CONG. REC. H12,157 (daily ed. Oct. 5, 1992).

69. These principles emerged largely from cases in which FERC had required electric utilities to file transmission tariffs as a condition for approving a utility merger or a wholesale power sale at market-based rates.

70. This language departs from FERC's prescriptions in the *Northeast Utilities* decision, which instructed that native load customers of the utility providing transmission service should be "held harmless." 58 F.E.R.C. ¶ 61,070, at 61,203 (1992).

71. H.R. 776, 102d Cong., 1st Sess. § 722 (1991). FERC's implementation of these policies is discussed *infra* Part III.A.

72. The pricing guidelines and FERC's decisional precedents implementing them, known generally as the "Northeast Utilities principles" or "NU principles" after a series of FERC orders involving Northeast Utilities, were both praised and attacked by Congressmen and Senators, just as they have engendered mixed reviews in pleadings before the FERC. The House proponents of transmission access generally praised FERC's transmission pricing precedents in the *Northeast Utilities* decisions. See 138 CONG. REC. H11,413 (daily ed. Oct. 5, 1992) (colloquy between Rep. Moorhead and Rep. Sharp). By contrast, Sen. Wallop, the Ranking Minority Member of the Senate Energy and Natural Resources Committee and staunch opponent of transmission access, roundly criticized virtually everything that FERC has done in the area of transmission pricing. See 138 CONG. REC. S17,619 (daily ed. Oct. 8, 1992) (Remarks of Senator Wallop).

limited to either cogeneration or small power production from specified resources; (2) avoid more than a 10% ownership of voting securities by resorting to a so-called "PUHCA pretzel" in which ownership is fragmented and divorced from operating control;<sup>73</sup> or (3) become a holding company (registered or exempt). These limited options constricted opportunities for non-utility generation. Increasing scarcity of economically attractive steam hosts for cogeneration as well as the fuel-use restrictions imposed on small power production constrained growth under the QF model. Lender hostility toward fragmented ownership and the separation of ownership from operating control made "PUHCA pretzels" difficult to structure and finance. Finally, becoming a holding company imposed unacceptable regulatory burdens and impossible financing requirements for an industry ideally suited to project financing.<sup>74</sup>

Title VII overcomes these barriers by creating a fourth avenue, the EWG. The attractiveness of this avenue is demonstrated by the fact that the first application for EWG status was filed with FERC within two days of enactment;<sup>75</sup> a total of three applications were filed within the first month.<sup>76</sup>

### 1. Industry Structure Prior to Energy Policy Act

PUHCA brought the holding company empires under reign by imposing both structural constraints and procedural controls. Structurally, holding companies—defined as a company that "directly or indirectly owns, controls, or holds with power to vote, 10% or more of the outstanding voting securities

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73. PUHCA pretzels have taken essentially two forms. First, because PUHCA is triggered by ownership of voting securities, a company can avoid PUHCA by acquiring only nonvoting common or preferred stock of a power project. *E.g.*, Ocean State Power, SEC No-Action Letter (Feb. 16, 1988) available in LEXIS, Fedsec Lib., NOACT File (by reducing voting interests of general partners, large equity interests were retained without becoming holding company affiliates under PUHCA). Second, parties to an energy project can establish ownership through a limited partnership with an exempt holding company serving as the general partner and equity participants serving as limited partners with no meaningful ability to control or influence the partnership's affairs. *E.g.*, Colstrip Energy Ltd. Partnership, SEC No-Action Letter (June 30, 1988) available in LEXIS, Fedsec Lib., NOACT File (no enforcement action recommendation where limited partner exercised no controlling influence); Colstrip Energy Co., SEC No-Action Letter (Jan. 21, 1988) available in LEXIS, Fedsec Lib., NOACT File. (same). In recent actions, however, the SEC has substantially lessened the viability of PUHCA pretzels based in limited partnership structures by requiring the general partner to hold approximately 50% of the equity in a project. ELEC. UTIL. WEEK, Apr. 8, 1991, at 8, 9.

74. To be competitive with franchise utilities, EWGs must ordinarily finance using non-recourse project financing, with initial common equity sometimes as small as 10 to 15%. By contrast, SEC regulations under sections 6(a) and 7 of PUHCA effectively require public utility subsidiaries of registered holding companies to maintain *no less than* 30% common equity capitalization. See 17 C.F.R. § 250.52(a)(3) (1992); see also Georgia Power Co., 45 S.E.C. 610, 614-15 (1974) (discussing SEC decisional precedents on minimum equity capitalization).

75. Commonwealth Atlantic Ltd. Partnership, No. EG93-1-000, 57 Fed. Reg. 49,467 (1992).

76. *Id.*; Doswell Ltd. Partnership, No. EG93-2-000, 57 Fed. Reg. 52,768 (1992); Hartwell Energy Ltd. Partnership, No. EG93-3-000, 57 Fed. Reg. 54,382 (1992).

of a public utility"<sup>77</sup>—were required to “simplify” by divesting all holdings not “consistent with the operation of an integrated public utility system”<sup>78</sup> and “reasonably incidental, or economically necessary or appropriate, to the operation of an integrated public utility system.”<sup>79</sup> These structural constraints forced investor-owned electric utilities to organize under one of three basic corporate models:<sup>80</sup> (a) single integrated corporations; (b) PUHCA-exempt holding companies operating predominantly in one state;<sup>81</sup> or (c) PUHCA-registered, interstate holding companies.<sup>82</sup> In addition to these structural requirements, holding companies that failed to qualify for specific exemptions<sup>83</sup> provided in the Act were made subject to extensive reporting, accounting, financing, and securities-issuance requirements intended to enforce simplification of ownership and standardize regulation by the Securities and Exchange Commission (SEC).<sup>84</sup>

77. 15 U.S.C. § 79b(a)(7)(A) (1988). “Public utility company” includes electric and natural gas distribution utility companies, but excludes natural gas pipelines, water, and telephone companies. *Id.* § 79b(a)(5).

78. *See id.* § 79k(b) (requiring SEC to simplify registered holding companies into integrated public utility systems); *id.* § 79b(a)(29) (defining integrated public utility system).

79. *Id.* § 79k(b)(1). Non-utility business may be retained by a registered holding company only if they are “reasonably incidental or economically necessary or appropriate.” The structural constraints were used to “bust the trusts.” When trust busting began in 1938, there were 214 holding companies controlling 922 utilities and 1,054 non-utility subsidiaries. When the trust busting campaign ended in 1955, there remained only 25 registered holding companies. *See Busting the Trusts, supra* note 10, at 21.

80. U.S. DEP’T OF ENERGY, ANALYSIS OF OPTIONS TO AMEND THE PUBLIC UTILITY HOLDING COMPANY ACT OF 1935, NATIONAL ENERGY STRATEGY, TECH. ANNEX 1, at 3 (1991/1992).

81. As of 1991, there were 85 holding companies that were exempt because their utility-related operations were “predominantly intrastate in character and carry on their business substantially in a single State,” 15 U.S.C. § 79c(a)(1) (1988); 31 were exempt because their holding company assets consisted “predominantly [of] a public utility company whose operations as such do not extend beyond the State in which it is organized and States contiguous thereto,” *id.* § 79c(a)(2). *See* SEC, Div. of Investment Management, Office of Public Utility Regulation, *Holding Companies Exempt from the Public Utility Holding Company Act of 1935 under Sections 3(a)(1) and 3(a)(2) Pursuant to Rule 2 Filings or by Order as of Sept. 1, 1991*, in FINANCIAL AND CORPORATE REPORTS (1991).

82. Simplification is continuously monitored and enforced under §§ 9 and 10 of PUHCA. Section 9 subjects registered and exempt holding companies to advance SEC review of many types of acquisitions, 15 U.S.C. § 79a(b)(1) (1988), and requires SEC approval of any acquisition of 5% or more of a public utility company. *Id.* § 79a(a)(2). Governing these pre-acquisition reviews, section 10 prohibits the SEC from approving any acquisition “unless the Commission finds that such acquisition will. . . tend[] towards the economical and efficient development of an integrated public utility system.” *Id.* § 79j(c)(2). As a result of the simplification requirements of PUHCA, there were only nine registered electric utility holding companies left as of December 31, 1990. SEC, Div. of Investment Management, Office of Public Utility Regulation, *Holding Companies Registered Under the Public Utility Holding Company Act as of Dec. 31, 1990*, in FINANCIAL AND CORPORATE REPORTS (1991).

83. 15 U.S.C. § 79c(a) (1988) (specifying five primary bases for exemption); *id.* § 79c(b), (d) (authorizing discretionary exemptions); *see generally* D. HAWES, UTILITY HOLDING COMPANIES, § 3.04[2]-[5] (Release #3, 1987).

84. *E.g.*, 15 U.S.C. § 79e(b) (1988) (relating to registration statements), *id.* §§ 79f, 79g (relating to securities transactions).

## 2. *New Class of Exempt Wholesale Generators*

The EAct amends PUHCA to create a new statutory category of power generators called exempt wholesale generators (EWGs). These generators qualify for special regulatory treatment under PUHCA and PURPA.

### a. *Benefits of EWG Status*

The most important benefit of EWG status is that ownership of one or more EWGs does not trigger Holding Company Act regulation. An EWG is not an “electric utility company” under section 2(a)(3)<sup>85</sup> of PUHCA; therefore, no provision of PUHCA applies.<sup>86</sup> For instance, companies such as Westinghouse or Dow Chemical may own an EWG subsidiary that generates power for sale at wholesale without becoming a holding company subject to PUHCA regulation. Moreover, an exempt public utility holding company operating in California, for example, could own an EWG subsidiary in Maine without losing its exempt status.

In addition, an EWG is deemed not to be “primarily engaged in the generation or sale of electric power” for purposes of sections 3(17)(C)(ii) and 3(18)(B)(2) of the Federal Power Act;<sup>87</sup> consequently, the owner of an EWG may also own interests in QFs without being subject to percentage ownership restrictions imposed on electric utility companies.<sup>88</sup>

A domestic EWG is, however, a “public utility” within the definition of the Federal Power Act,<sup>89</sup> and is therefore subject to regulation under Parts II and III of the FPA, including regulation of rates and charges for sales of electricity or leased capacity,<sup>90</sup> tariff requirements,<sup>91</sup> and information reporting.<sup>92</sup>

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85. 15 U.S.C. § 79b(a)(3) (1988) (defining “electric utility company as any company which owns or operates facilities used for the generation, transmission, or distribution of electric energy for sale” other than various types of self generation).

86. EAct § 711 (adding PUHCA § 32(e)) (to be codified at 15 U.S.C. § 79z-5a(e)).

87. 16 U.S.C. § 796(17)(C)(ii), (18)(B)(ii) (1988).

88. *See supra* note 19.

89. 16 U.S.C. § 824(e) (1988). If located outside of the United States, however, special new foreign investment provisions of the EAct exclude the EWG from the definition of “public utility.” These foreign investment provisions are discussed *infra* Part II.C.

90. 16 U.S.C. § 824d (1988).

91. *Id.* § 824d(c)-(e) (1988).

92. 16 U.S.C. §§ 825-825c (1988).

### b. EWG Eligibility

A person eligible to become an EWG is a person (including an affiliate<sup>93</sup> of an electric utility<sup>94</sup>) who is exclusively in the business of owning or operating "eligible facilities" and selling electric power at wholesale<sup>95</sup> (including electric power generated by someone other than that person).<sup>96</sup> "Eligible facility" is, in turn, defined to mean a power generation facility or a "portion" of a facility, wherever located, that is used for the generation of electricity exclusively for sale at wholesale, or used for the generation of electricity and leased to one or more public utilities.<sup>97</sup> Eligible facilities include interconnecting transmission lines.<sup>98</sup>

Since enactment of the EPAAct, FERC has issued several significant orders delineating the permissible scope of operations at an eligible facility. First, FERC has ruled that a single facility may simultaneously be a QF and an eligible facility.<sup>99</sup> In connection with that ruling and an analysis of EPAAct's

93. PUHCA ascribes separate and distinct meanings to the terms "affiliate," 15 U.S.C. § 79b(11) (1988), "associate company," *id.* § 79b(10), and "subsidiary company," *id.* § 79b(8). While these distinctions are important to the construction of PUHCA's provisions, for the sake of simplicity, in this Article we use the term "affiliate" to include "associate company" and "subsidiary company."

94. Including affiliates of electric utilities was controversial and opposed by many consumer groups. *See, e.g.,* Cheryl Romo, *Revising PUHCA: The Crusade Resumes*, PUB. UTIL. FORT., Oct. 27, 1988, at 33, 35 (summarizing consumer and environmental opposition to allowing utility affiliates to be eligible for PUHCA exemption). Providing EWG status to utility affiliates is counterbalanced in the new law by special restrictions on the transactions into which utility affiliates may enter. *See infra* notes 112-15 and accompanying text.

95. The conjunctive "and" in this definition is significant and has required FERC's interpretive guidance. FERC has addressed the meaning of this conjunction in situations where the applicant for EWG status was a so-called passive owner-lessor of an otherwise eligible facility, *InterAmerican Leasing Co.*, 62 F.E.R.C. ¶ 61,283 (1993), and where the applicant was an operator, but not owner, of the otherwise eligible facility, *KFM Pepperell, Inc.*, 62 F.E.R.C. ¶ 61,182 (1993). FERC denied both applications on the ground that only the lessee, but not the lessor applicant in *InterAmerican*, and only the owner, but not the operator applicant in *Pepperell*, were identified in the applications as sellers of electric power at wholesale. *See InterAmerican*, 62 F.E.R.C. at 62,818; *Pepperell*, 62 F.E.R.C. at 61,213-14. Soon after both decisions, FERC reconsidered its strictly mechanistic interpretation of "and" because it was having the "unintended consequence of discouraging the development of EWGs as contemplated by Congress." Filing Requirements and Ministerial Procedures for Persons Seeking Exempt Wholesale Generator Status, Order No. 550-A, 58 Fed. Reg. 21,250 (April 20, 1993), *reprinted in* III F.E.R.C. ¶ 30,969 [hereinafter Order No. 550-A] (quoting 137 CONG. REC. S1512-13 (daily ed. Feb. 5, 1991) (remarks of Sen. Johnston)). FERC proceeded to adopt sensible regulations that, in effect, treat leases of a facility to a public utility as being equivalent to a sale of the facility's power at wholesale, 18 C.F.R. § 365.3(a)(2)(ii) (1992), and allow operators to satisfy the "selling" requirement by representing themselves to be "agents" of the facility owner or "other person (or persons) who sell electric energy at wholesale" from the facilities in question. *Id.* § 365.3(a)(1)(iii).

96. H.R. CONF. REP. NO. 1018, 102d Cong., 2d Sess. 381, 388 (1992); 138 CONG. REC. H12,092.

97. EPAAct § 711 (adding PUHCA § 32(a)(2)) (to be codified at 15 U.S.C. § 79z-5a(a)(2)).

98. *Id.*

99. *Richmond Power Enter., L.P.*, 62 F.E.R.C. ¶ 61,157, at 62,098 (1993) ("a facility that satisfies the statutory requirements of both PUHCA and PURPA may be both an eligible facility and a QF"). FERC instructed further that both status determinations are separate and must be made independently. *Id.* at 62,098 n.10. The dual status option confirmed in *Richmond Power* is likely to be attractive to cogenerators and lenders to cogeneration projects. For whatever reason, if the cogenerator were to lose its QF eligibility—e.g., due to loss of a steam host or a change in utility ownership share—PUHCA exemption would nevertheless automatically continue pursuant to the EWG status determination.

legislative history, FERC concluded that "it is clear that a person otherwise meeting the requirements for EWG status may engage in the sale of by-products of electric generation such as steam and fly ash, incidental to the sale of electric energy at wholesale, without violating the exclusivity requirement."<sup>100</sup> Cogenerated steam is an obvious candidate for status as an incidental by-product; the parameters of this "by-product" envelope, however, remain uncertain and are sure to be probed on a case-by-case basis.<sup>101</sup> Further, FERC has also ruled that "facility" under the statute means a "physical facilit[y] . . . used for the generation of electric energy that is sold"; consequently, a person that only markets or brokers electricity generated by others, but neither owns nor operates a power generating station, is not eligible.<sup>102</sup>

To become an EWG, an eligible person must apply to FERC.<sup>103</sup> FERC, in turn, is required to make a "ministerial" determination of the applicant's EWG status within 60 days.<sup>104</sup> An entity that has made a good faith

100. *Id.* at 62,098. "[T]he definition of an EWG 'permits an exempt wholesale generator to sell by-products of electric generation . . . incidental to an EWG's involvement in wholesale electric generation.'" *Id.* (quoting remarks of Sen. Johnston, 138 CONG. REC. S17,644 (daily ed. Oct. 8, 1992)).

101. By-products other than steam result from fuel preparation and the application of emission controls on electric power stations. Converting coal into cleaner-burning gas produces other gasses that can be marketed as by-products. Some flue gas desulfurization technologies produce chemical or mineral by-products for which markets exist. In *Elm Energy & Recycling (UK) Limited*, 63 F.E.R.C. ¶ 61,201 (1993), FERC interpreted by-product to extend to sales of scrap steel wire and other chemicals and metals produced and recycled at a 25 megawatt facility fueled by used rubber tires and rubber tire scraps. By permitting EWGs to engage in sales of these by-products, overall revenues to the power generator will be increased, with possible savings to consumers of the generator's electricity.

102. *Louis Dreyfus Elec. Power, Inc.*, 62 F.E.R.C. ¶ 61,234, at 62,580 (1993) (rejecting application of electricity marketer who was only in the business of owning power sales agreements used to buy and resell (but not generate) electric power).

103. EPAAct § 711 (adding § 32(a)(1) to PUHCA (to be codified at 15 U.S.C. § 79z-5a(a)(1))). FERC has already issued a final rule specifying: (a) what must be contained in the application; and (b) how applications will be processed. *Filing Requirements and Ministerial Procedures for Persons Seeking Exempt Wholesale Generator Status*, Order No. 550, 58 Fed. Reg. 8897 (1993), *reprinted in* III F.E.R.C. ¶ 30,964, *clarified and amended*, Order No. 550-A, *supra* note 95 [hereinafter Order No. 550]. The very simple procedures require a sworn statement by the applicant setting out its eligibility under the definition of EWG and eligible facility. 18 C.F.R. § 365.3 (1992). Applications are to be noticed in the Federal Register, and notice is to be given to interested states and the SEC. After an application has been granted, the EWG has an ongoing obligation to notify FERC of any material changes in the facts represented in the application. Because of the short statutory deadline of 60 days to act on applications, FERC will not issue deficiency letters to applicants and provide them an opportunity to supplement deficient application; rather, FERC will only grant or deny applications. Order No. 550, *supra*, 58 Fed. Reg. at 8903; Order No. 550-A, *supra* note 95, 58 Fed. Reg. at 21,253; *see* *NW Energy (Williams Lake) Limited Partnership*, 62 F.E.R.C. ¶ 61,235, at 62,581 (1993) (application denied because applicant failed to aver that "it is or will be engaged exclusively in the business of owning eligible facilities and selling electric energy at wholesale, as required by the plain meaning of section 32(a)(1) of PUHCA").

104. Judicial review of FERC's determination is available, if at all, only under PUHCA § 25, 15 U.S.C. § 79y (1988), which confers jurisdiction to the United States District Courts over violations of PUHCA and rules and regulations thereunder. Certain non-utility generators have expressed concern that FERC's status determinations will lack needed finality because "there is no time limit for obtaining judicial review under section 25 of PUHCA." Order No. 550-A, *supra* note 95, 58 Fed. Reg. at 21,251. This concern is probably overstated because review under PUHCA § 25 will ordinarily be of the applicant's ongoing compliance with EWG status requirements and not of FERC's initial status determination.

application for EWG status is deemed to be an EWG pending the FERC's determination.

This application process becomes the exclusive vehicle for an EWG to obtain a PUHCA exemption. The law closes the exemption door on "PUHCA pretzels," while grandfathering existing pretzels.<sup>105</sup> Following enactment, SEC orders under PUHCA "shall not be required for the purpose, or have the effect, of exempting [EWG eligible] persons from treatment as an electric utility company under section 2(a)(3) or exempting such persons from any provision of [PUHCA]."<sup>106</sup>

*c. Special Cases—"Spin-Offs" and "Hybrids"*

The new law establishes special rules for converting plants owned by electric utilities into "eligible facilities." The political compromise included in the final legislation was to grant EWG status to such "spin-offs" only with the consent of every affected state utility regulatory commission. These commissions must find that the spin-off is in the public interest, will benefit consumers, and is consistent with state law.<sup>107</sup> The goal of these protections is to ensure that the utility shareholders cannot engage in sweetheart deals that will sell utility assets at below value to an unregulated affiliate, thereby benefitting shareholders at the expense of ratepayers.

The EPAct accommodates, with limitations, "hybrid" plants where a portion of a plant is owned or operated by an EWG and another portion is owned or operated by an electric utility. However, an electric utility and an EWG affiliate of that utility may not co-own or co-operate the same generation station, unless the EWG's share of the facility became an "eligible facility" through the spin-off approval process described above. For example, a utility and its affiliated EWG could not both be participants in the development of a *new* power station or in the purchase of a power station from a third party. The utility could, however, purchase a power station on its own and then spin off a portion of it to an affiliated EWG, so long as the necessary state approvals for the spin-off are first obtained. These hybrid provisions are designed to protect utility ratepayers from forms of cross-subsidization that could occur when a regulated utility and its unregulated EWG affiliate co-own a single facility.

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105. See *supra* note 73.

106. EPAct § 711 (adding PUHCA § 32(i)) (to be codified at 15 U.S.C. § 79z-5a(i)).

107. EPAct § 711 (adding PUHCA §32(c)) (to be codified at 15 U.S.C. § 79z-5a(c)). In the case of a facility owned by an affiliate of a registered holding company, the spin-off must be approved by every state commission with jurisdiction over an affiliate of the holding company.

d. *Ownership of EWGs by Registered Holding Companies*

A number of special provisions deal with ownership of EWGs by registered holding companies. Generally, registered companies are permitted to hold ownership interests in EWGs without SEC approval.<sup>108</sup> Registered company ownership of an EWG is deemed to be in compliance with PUHCA's requirements that holding company properties be both "consistent with the operation of an integrated public utility system" and "reasonably incidental . . . to the operations of an integrated public utility system."<sup>109</sup> The law also directs that the SEC should not consider the effect on capitalization or earnings that any EWG subsidiary has on a registered company.<sup>110</sup>

Certain PUHCA provisions, however, continue to apply to EWG-related activities by registered holding companies. Specifically, the SEC retains jurisdiction under PUHCA over the issuance or guarantee of securities by a registered company or its subsidiary to acquire or own an eligible facility, and over service, sale, or construction contracts between a registered company and an affiliate EWG.<sup>111</sup>

3. *Restrictions on EWG Transactions*

a. *Affiliate Transactions*

The new law bars power sales to an electric utility from an EWG affiliated with that utility unless "every State commission having jurisdiction over the retail rates of [the purchasing] electric utility" approves the transaction.<sup>112</sup> In particular, the state commissions must determine that the transaction (1) will benefit consumers, (2) will not violate state law (including applicable requirements concerning least-cost planning), (3) will not provide the EWG with any unfair competitive advantage by virtue of the affiliation, and (4) will be in the public interest.<sup>113</sup> In essence, federal law prohibits self-dealing in power sales, but allows the affected states to override that prohibition on a case-

108. *Id.* § 711 (adding PUHCA §32(g)) (to be codified at 15 U.S.C. § 79z-5a(g)).

109. *Id.* § 711 (adding PUHCA § 32(h)(1),(2)) (to be codified at 15 U.S.C. § 79z-5a(h)(1),(2)).

110. *Id.* (adding § 32(h)(4) to PUHCA) (to be codified at 15 U.S.C. § 79z-5a(h)(4)). In deciding whether to approve issuances or sales of securities by registered companies to acquire EWGs, the SEC is instructed to consider EWG's capitalization and earnings only where the issuance or sale, together with the EWG's capitalization and earnings, would have a "substantial adverse impact" on the registered system's financial integrity.

111. *Id.* § 711 (adding § 32(h) to PUHCA) (to be codified at 15 U.S.C. § 79z-50a(h)). SEC determinations under this retained jurisdiction are expedited by a requirement that it act on security issuances or guarantees within 120 days. *Id.* (adding § 32(h)(5)) (to be codified at 15 U.S.C. § 79z-5a(h)(5)).

112. *Id.* § 711 (adding § 32(k) to PUHCA) (to be codified at 15 U.S.C. § 79z-5a(k)). There are also special provisions for utilities not subject to state regulation. *Id.* (adding § 32(k)(2)(B) to PUHCA).

113. *Id.* § 711 (adding § 32(k) to PUHCA) (to be codified at 15 U.S.C. § 79z-5a(k)).

by-case basis. The new law also prohibits “reciprocal arrangements”—i.e., “daisy chains”—in which non-affiliates agree to favor each other’s affiliates or otherwise enter agreements contrary to the self-dealing and other restrictions created by the new law.<sup>114</sup>

b. *Affiliate Preference or Advantage*

The new law recognizes that potential abuse of a utility’s monopoly power extends beyond electricity sales between a utility and an EWG affiliate. Specifically, utility resources may be made available to an EWG affiliate in order to enhance that affiliate’s competitiveness in the wholesale power market. In order to police this problem, and to protect both the ratepayers of the affiliated utility and the competitiveness of the emerging generation market, the new law prohibits EWG power sales that can be demonstrated to be the product of preferences or advantages that the EWG seller obtained through affiliation with a utility. New section 213 deems unlawful any rate or charge that an EWG receives if the Commission finds that the rate or charge results from the EWG’s receipt of “any undue preference or advantage from an electric utility which is an associate company or an affiliate of the [EWG].”<sup>115</sup>

The breadth of this section will surely be tested. Arguably, it applies both in situations of below-market or predatory pricing and situations of supra-competitive rates and charges. For example, a utility might provide, directly or through a service company affiliate, discounted or otherwise under-priced construction or engineering services to construct an eligible facility for an affiliate EWG. If provision of those services allows the EWG to reduce its rates and charges for power from that facility, FERC could find an undue preference or advantage and rule the rates and charges unlawful. Conversely, two utilities may agree to enter into power sales agreements with the other’s EWG affiliate and pay equivalent supra-competitive prices—a classic “daisy chain.” Those rates and charges likewise could be found unlawful.

c. *Retail Sales*

One of the conditions of qualifying as a domestic EWG is that all electricity generated is sold at wholesale rather than at retail.<sup>116</sup> This restriction is intended to protect electric utility ratepayers in the U.S. by ensuring that EWGs will not “cherry pick” premium industrial loads away from those franchise

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114. *Id.* § 711 (adding § 32(l) to PUHCA) (to be codified at 15 U.S.C. § 79z-5a(1)).

115. *Id.* § 724 (adding FPA § 214) (to be codified at 16 U.S.C. § 824m). The FPA had already empowered FERC to take action against any utility that provides undue preference or advantage, irrespective of whether the recipient is an affiliate. *See* 16 U.S.C. § 824d(b) (1988).

116. *Id.* § 711 (adding § 32(a) to PUHCA) (to be codified at 15 U.S.C. § 79z-5a(a)).

utilities, with resulting shifts of embedded costs to remaining commercial and residential customers.

However, the law permits an EWG to make retail sales of electricity generated at eligible facilities located outside the U.S., provided that none of the power is sold to ultimate consumers in the U.S.<sup>117</sup>

### C. Foreign Utility Ownership

Wholly apart from creating EWGs, the EPAct also greatly expands the opportunities for holding companies, utilities, and non-utilities to own all types of foreign utilities, including electricity transmission and distribution assets as well as generation facilities. Foreign utility companies<sup>118</sup> are not considered to be "public utility companies" under PUHCA,<sup>119</sup> so that ownership of foreign utilities will not trigger PUHCA regulation.

Until now, PUHCA's definition made no distinction between domestic and foreign. Consequently, a U.S. company's acquisition of a 10% or greater ownership interest in a foreign public utility company caused that domestic company to become a holding company subject to PUHCA. Existing registered or exempt holding companies required SEC approval of such foreign investments.

Consumer groups and state regulators generally opposed this exemption based on fears that investments in foreign utilities by domestic holding companies and public utilities would syphon resources (personnel as well as cash) away from the regulated domestic operations. In addition, investments in foreign utilities could be relatively risky and thus might undermine the financial stability of the domestic utility at the expense of ratepayers.

In response to these concerns, an array of protections were added. For example, public utility companies are prohibited from pledging or encumbering domestic utility assets for the benefit of a foreign utility company,<sup>120</sup> and from issuing securities to finance acquisition, ownership, or operation of a foreign utility.<sup>121</sup> Exempt holding companies are permitted to invest abroad

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117. *Id.* § 711 (adding § 32(b) to PUHCA) (to be codified at 15 U.S.C. § 79z-5a(b)).

118. A foreign utility company is an electric or gas utility that: (1) has no utility-related assets within the U.S.; (2) has no income derived from selling gas or electricity in the U.S.; (3) is not a public utility operating within the U.S. and has no subsidiary that is a public utility operating within the U.S.; and (4) provides notice to the SEC. *Id.* § 715 (adding PUHCA § 33(a)(3) (to be codified at 15 U.S.C. § 79z-5b(a)(3))).

119. *Id.* § 715 (adding PUHCA § 33(a)(1)) (to be codified at 15 U.S.C. § 79z-5b(a)(1)).

120. *Id.* § 715 (adding PUHCA § 33(g)) (to be codified at 15 U.S.C. § 79z-5b).

121. *Id.* § 715 (adding PUHCA § 33(f)) (to be codified at 15 U.S.C. § 79z-5b(f)). In certain cases, public utilities are permitted to issue securities for these purposes if each state commission with jurisdiction concurs and the volume of securities issued in connection with the foreign utility is small compared with the company's capitalization.

only if their state commissions do not object.<sup>122</sup> With regard to registered holding companies, the SEC retains PUHCA jurisdiction over issuance of securities and guarantees related to the foreign utility and all relationships between a foreign utility and a registered company or its affiliates.<sup>123</sup> The SEC has already proposed rules concerning foreign utility acquisitions, which are designed to ensure that ratepayers of a registered company's affiliates are protected.<sup>124</sup>

Inclusion of this foreign utility exemption in the final legislation was remarkable in that no parallel provision was in either the Senate or House bills and no congressional hearings ever addressed the subject. The foreign utility exemption was ultimately propelled into the final legislation by the perception that PUHCA was preventing the U.S. power industry from competing with foreign companies in the expanding international market for electric power. Opportunities in the international market have burgeoned in industrializing countries in Latin America, Asia, Eastern Europe, and the former Soviet Union, as an increasing number of previously state-owned utilities are being "privatized."<sup>125</sup> Moreover, pre-EPAAct actions by the SEC had already suggested the need for reform—the SEC had approved foreign utility investments by six holding companies<sup>126</sup> in the four months preceding enactment.

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122. Exempt holding companies may not invest in foreign utilities unless every state commission with jurisdiction over an associate company or affiliate of the holding company has certified to the SEC that "it has the authority and resources to protect ratepayers subject to its jurisdiction and that it intends to exercise its authority." *Id.* § 715 (adding § 33(a)(2) to PUHCA) (to be codified at 15 U.S.C. § 79z-5b(a)(2)). State commissions may revise or withdraw this certification, so they can effectively bar investment in foreign utilities.

123. *Id.* § 715 (adding § 33(c)(2) to PUHCA) (to be codified at 15 U.S.C. § 79z-5b(c)(2)). Although state commissions with jurisdiction over utilities that are part of a registered holding company system do not have any disapproval rights, they can make recommendations to the SEC concerning a registered holding company's relationship to a foreign utility, which the SEC "shall reasonably and fully consider." *Id.*

124. *Id.* § 715 (adding § 33(c)(1) to PUHCA) (to be codified at 15 U.S.C. § 79z-5b(c)(1)). Proposed Rules 53 and 55 create a "safe harbor" under which a registered holding company may issue securities to acquire a foreign utility so long as (a) total investment in EWGs and foreign utilities does not exceed 50% of the holding company's retained earnings, (b) separate books and records are kept for each EWG and foreign utility, and (c) no more than 2% of domestic holding company employees render services to EWGs or foreign utility operations. Proposed Rules and Forms Relating to Exempt Wholesale Generators and Foreign Utility Companies, 58 Fed. Reg. 13,727 (Mar. 15, 1993). Proposed Rule 57 imposes ongoing filing requirements under which registered holding companies must annually reaffirm that they satisfy the requirements of Rules 53 and 55. *Id.*

125. See, e.g., James E. Rogers, Jr., *U.S. Losing Out In World Power Market Due to PUHCA*, THE ENERGY DAILY, Sept. 15, 1992, at 4; see generally Bernard Tenenbaum et al., *Electricity Privatization: Structural, Competitive, and Regulatory Options* 1-6, ENERGY POLICY, Dec. 1992.

126. Southern Company, PUHCA Release No. 35-25639 (Sept. 23, 1992); Dominion Resources, Inc., PUHCA Release No. 35-25598 (Aug. 3, 1992) (Argentina); Duke Power Co., PUHCA Release No. 35-25595 (July 31, 1992) (Argentina); Houston Industries, Inc., PUHCA Release No. 35-25590 (July 24, 1992) (Argentina); PSI Resources, Inc., PUHCA Release No. 35-25570 (July 2, 1992) (Argentina); SCEcorp, PUHCA Release No. 35-25564 (June 29, 1992) (Australia).

D. *PURPA Amendments on State Consideration of Wholesale Power Market Issues*

New amendments to PURPA require regulators in states that require or allow their utilities to purchase long-term wholesale power to determine, within one year, whether performing “general evaluations” of four issues is consistent with state law and appropriate to carry out the purposes of PURPA.<sup>127</sup> The four issues are: (1) the impact of power purchases on utility cost of capital; (2) the impact on reliability of EWG capital structures; (3) the wisdom of advance approval for power purchase contracts; and (4) the need for a third-party power supplier to ensure the adequacy of its fuel supplies.

As was the case with the 1978 federal ratemaking guidelines<sup>128</sup> to which these new purchased power evaluations were added, states are not required to take any action, i.e., they need not conduct the four evaluations, if they find that doing so would not be consistent with state law<sup>129</sup> or would not be appropriate under PURPA.<sup>130</sup> It is unclear, however, whether a state must make these determinations before authorizing any new long-term power purchases by a utility subject to its jurisdiction.

Of the four issues listed for state evaluation, the first two issues reflect some of the favorite laments of investor-owned utilities, which increasingly are being required by state resource plans to consider power purchases as an alternative to building new capacity themselves. States would evaluate whether purchasing long-term power in lieu of building new capacity will adversely affect a utility’s cost of capital and, in turn, its rates, and whether EWGs threaten reliability or obtain an unfair advantage by using proportionally greater debt than utilities.<sup>131</sup> Some utilities contend that the fixed obligations that they incur under purchase power contracts increase financial risk and, in turn, the cost of capital. Moreover, they protest that the ability to use project financing confers on QFs and EWGs certain cost of capital advantages not enjoyed by utilities.

State regulators are also asked to evaluate “whether to implement procedures for the advance approval or disapproval” of power purchases by the utilities that they regulate.<sup>132</sup> Preapproval—whether of “buy” or “build” decisions—is attractive to both investor-owned utilities and non-utility power

127. EPAAct § 712 (amending PURPA § 111) (to be codified at 16 U.S.C. § 2621).

128. 16 U.S.C. § 2621 (1988).

129. *Id.* § 2621(a) (“Nothing . . . prohibits any state regulatory authority . . . from making any determination that it is not appropriate to implement any such standard, pursuant to its authority under otherwise applicable State law”).

130. The relevant purposes are those of Subtitle A of Title I of PURPA: conservation; efficient use of facilities and resources; and equitable electricity rates. *Id.* §2611.

131. EPAAct § 712 (adding PURPA § 111(d)(10)(i),(ii)) (to be codified at 16 U.S.C. § 2621(d)(10)(i),(ii)); see *supra* note 74.

132. *Id.* § 712 (adding PURPA § 111(d)(10)(iii)) (to be codified at 16 U.S.C. § 2621(d)(10)(iii)).

producers seeking to reduce regulatory or financial risk associated with after-the-fact prudence reviews. State regulators can be expected to continue their opposition to *binding* pre-approval of build decisions,<sup>133</sup> over which they typically insist on exercising ongoing oversight. They may, however, prove more receptive to the new law's suggestion of pre-approval of power sales agreements for several reasons. First, the terms of purchase are known in advance. Second, the need for the purchase should be reasonably ascertainable. Perhaps most importantly, in the purchase context, the power seller undertakes many significant risks that would otherwise fall on the utility and its ratepayers. Those shifted risks include costs associated with project development, construction cost overruns, and delays in completion, as well as certain financial risks associated with changes in interest rates, relevant tax policy, or the cost of equity capital.<sup>134</sup>

The fourth issue state regulators may choose to evaluate is "whether to condition . . . the approval of the purchase of power" on a "reasonable assurance of fuel supply adequacy."<sup>135</sup> While not an unreasonable concern, this recommended evaluation begs the question why adequacy of fuel should be of greater concern to a state regulator in the context of a power purchase decision than in a utility decision to build new generating capacity. In the context of building new capacity, the utility's commitment to a fuel source and its adequate supply is for the life of the plant (possibly as long as fifty years), whereas it is only for the life of the power sales agreement (fifteen to twenty years) in the buy context.

### III. Issues to be Addressed by Federal and State Regulators

Whether a competitive wholesale power market emerges from these fundamental changes in federal law will depend in large measure on how FERC and the state regulators implement the new law. Particularly in the area of transmission access, FERC must promptly articulate simple and standardized rules upon which industry participants can rely. Key implementation issues confronting the Clinton Administration and the states are discussed below.

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133. See generally J.C. Person, *Construction Cost Pre-Approval: Too Much of a Good Thing*, PUB. UTIL. FORT., Apr. 15, 1993, at 26 (comparing alternatives to after-the-fact prudence reviews).

134. This allocation of risk is relatively standard in performance-based contracts for dispatchable power, which is increasingly the most common form of power sales agreement. See, e.g., M. Willrich & W.L. Campbell, *Risk Allocation in Independent Power Contracts*, ELEC. J., March 1992, at 54, 55-60; Mark J. LaFratta, *The New Utility Offensive: The Credit Rating Weapon*, at 6-8 (presented at Cogeneration and Independent Power Market Conference, March 1993) [hereinafter *New Offensive*] (on file with the *Yale Journal on Regulation*).

135. EPC Act § 712 (adding PURPA § 111(d)(10)(iv)) (to be codified at 16 U.S.C. § 2621(d)(10)(iv)).

### A. *Implementing Transmission Access*

Once the market for transmission services adjusts to the new rights and responsibilities established by the EAct, it is expected that most wheeling requests will be handled consensually by the parties, without resort to FERC's new authority to compel transmission. This evolution can happen only after FERC establishes clear and easily applicable standards and guidelines on basic issues such as pricing, capacity allocation or expansion, and reliability.

#### 1. *Setting Rates for Wheeling Service*

##### a. *Embedded Cost Versus Incremental Cost Debate*

In spite of the jumbled statutory directions concerning transmission rates contained in the new law, it appears that traditional just and reasonable standards will continue to govern transmission rates and charges. Within these parameters, no single pricing mechanism is without defect. What is important is that the regulators determine first what policy they intend to promote through pricing. In addition to the three Northeast Utilities pricing guidelines,<sup>136</sup> FERC's apparent policy is to encourage (some might say "strong arm") utilities and state regulators to expand transmission capacity wherever and whenever needed to accommodate an efficient and competitive bulk power market.

In light of that apparent policy, FERC can be expected to continue to require that transmission services be priced on the hybrid embedded cost/incremental cost model developed in its *Northeast Utilities* and *Penelec* decisions.<sup>137</sup> Under that model, the transmitting utility is entitled to recover operating costs, plus the capital costs of dedicated enlargements (e.g., radial lines or other facilities used exclusively for the wheeling service<sup>138</sup>), plus an allocable share of the capital costs of the transmission system equal to the greater of embedded cost or incremental cost; for purposes of this last cost component, incremental cost is defined as the lesser of the cost of expanding the system or the opportunity costs the transmitting utility incurs in order to provide the requested service. Where the transmission system of the transmitting utility is not constrained—i.e., where there is sufficient unused capacity to provide the requested transmission—incremental costs will ordinarily be lower

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136. *Northeast Util. Serv. Co.*, 58 F.E.R.C. ¶ 61,070, at 61,203 (1992), *aff'd in relevant part*, 1993 WL 156,776 (1st Cir. May 19, 1993). Congress considered codifying these principles, but ultimately they were dropped from the legislation. See *supra* notes 69-72 and accompanying text.

137. *Northeast Util. Serv. Co.*, 58 F.E.R.C. ¶ 61,070, at 61,206-07; *Pennsylvania Elec. Co.*, 60 F.E.R.C. ¶ 61,034, at 61,123-24 (1992); *Pennsylvania Elec. Co.*, 58 F.E.R.C. ¶ 61,278, at 61,871-71 (1992); see *Public Serv. Co. of Colo.*, 62 F.E.R.C. ¶ 61,013, at 61,061-62 (1993).

138. See *Public Serv. Co. of Colo.*, 62 F.E.R.C. ¶ 61,013, at 61,060.

than embedded cost and the resulting rate will recover only the embedded capital cost of the transmission facility. Where constraints exist, however, incremental costs (either expansion cost or opportunity cost) may exceed embedded cost.

Under FERC's model, expansion becomes economically justified for a utility as soon as the value of lost opportunities exceed the cost of expansion. Although this formula for allocating capital costs has been criticized by both transmission owners and users,<sup>139</sup> it does effectively achieve FERC's apparent primary objective of forcing efficient expansion of constrained systems through economic incentives. What is not addressed, however, is how constrained capacity is to be allocated when expansion is not undertaken or, if undertaken, before it is completed.<sup>140</sup> One simple rule that could go a long way toward simplifying capacity allocation disputes would be to require that firm service be invariably prioritized over all less-than-firm services.

#### b. *Moving to Mileage-Based Rate Design*

Another ratemaking question soon to be presented to FERC is what costs a transmission rate should recover—viz., should rates be designed to reflect the capital costs associated with the specific facilities used to provide each transmission service? Interstate transmission rates traditionally have been set by FERC using a simple “postage-stamp” design, with a single price irrespective of distance covered. Although the capital costs incurred in providing transmission service vary, in part, with distance,<sup>141</sup> postage-stamp

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139. The debate over FERC's model centers on issues of cross-subsidies between customer classes, primarily between traditional retail (and wholesale) sales customers and wholesale transmission (i.e., wheeling customers). As recently summarized by the FERC,

[t]he debate . . . centers on two approaches to pricing transmission on a constrained transmission system. First is the “or” approach . . . [u]nder [which] the [transmitting] utility may charge the higher of embedded costs or opportunity costs capped at the incremental cost of expansion. Second is the “and” approach . . . [u]nder [which] the utility would be allowed to charge both embedded costs and opportunity costs capped at the incremental cost of expansion.

Pennsylvania Elec. Co. 60 F.E.R.C. ¶ 61,034, at 61,124-25 (1992). As a general matter, transmitting utilities advocate the “and” approach; the FERC formulated and insists on the “or” approach; and transmission users either support FERC's “or” approach or argue in favor of straight embedded or incremental cost pricing with no switching back and forth depending on whether a system is constrained. Compare Berg, *EI Files Penelec Rehearing Request*, PUB. UTIL. FORT., May 15, 1992, at 96. (describing Edison Electric Institute's argument that transmitting utility should receive embedded cost plus opportunity costs or embedded costs plus incremental expansion costs), with Public Serv. Co. of Colo., 62 F.E.R.C. ¶ 61,013, at 61,060-62 (1993) (reiterating FERC policy that transmitting utility is entitled to higher of incremental or embedded costs, but not both).

140. See Charles E. Bayless, *Transmission Pricing: Striking a Balance*, PUB. UTIL. FORT., Oct. 15, 1992, at 13, 14-16.

141. Transmission operating costs, with the exception of load losses, are largely not a function of transmission distance. Likewise, as much as 40% of a transmitting utility's capital costs allocated to transmission may represent investments in substations, which bear no relationship to distance.

rates have persisted as a convenient fiction<sup>142</sup> that simplifies the pricing of transmission services. The lack of relationship to the actual capital costs of capacity used to provide a specific transmission service could easily be ignored when transmission services were simply being sold from one utility to another; any inaccuracies could be presumed to "even out."

The universe of transmission purchasers, however, has now expanded and numerous sellers and purchasers of power will soon be vying for transmission capacity. In this expanded market, transmission owners can be expected to seek full recovery of actual capital costs by pushing for rates that are a direct function of the distance of a transmission service. Conversely, transmission users who require transmission service over only short distances can be expected to insist that charges be mileage-based rather than reflecting average cost within a larger postage-stamp zone.

Rates that reflect mileage, in contrast to postage-stamp rates, could also make siting of power plants more efficient. In balancing the various site-specific factors associated with power plant development—including the cost of real estate, access to fuel, and regional pollution control requirements—generation plant developers should also consider true transmission costs of alternative sites. Mileage-based rates or other rates that reflect the capital cost of impacted capacity could provide more accurate price signals to power plant developers, and thus improve the economic efficiency of their siting decisions.<sup>143</sup>

Notwithstanding these theoretical attractions, the complexity of implementing and administering mileage-based rates may outweigh the possible benefits. Capital costs are not solely a function of the length of a transmission line; for example, capital costs of transmission lines also vary in relation to vintage (with newer capacity generally more costly than older equivalent capacity), and voltage (with higher voltages generally costing less per megawatt-mile). Should the charge for use of an older or higher voltage line be less than the charge for transmission service of equal length that must use newer or lower voltage facilities? Moreover, if impacted capacity is to be a factor, then it should be recognized that counterflows effectively create additional capacity by reducing loads on existing facilities. Should those who transmit against the flow be charged for capital costs or should they receive

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142. Much of a utility's transmission capacity is used in connection with distributing power to the utility's own retail customers. Postage stamp pricing of these services is not only convenient, but also mandated in many instances by legal requirements that service be provided to all customers within the franchise area at essentially the same rate regardless of variations in actual costs of transmission associated with serving different customers.

143. While siting decisions could become more efficient, transmission rates based on mileage would only rarely affect dispatching from existing generating facilities, because potential transmission savings will in most cases be small relative to energy savings achievable through economic dispatch.

some offsetting payment for reducing loads? These questions should be addressed before the administrative simplicity of postage stamp rates is discarded.

c. *Determining Who Gets Paid*

What rate the transmission customer should pay is not the only issue. Perhaps even more important for the new market in transmission will be determining which utilities are entitled to payment for a wheeling service. This is an issue because electricity to be carried from point A to point B does not necessarily flow over the most direct path between those two points. To the contrary, power placed on the system at point A will spread throughout interconnected systems according to physical principles known as Kirchoff's laws. The difference between hypothetical flows on the contract path (point A directly to point B) and the actual electrical flows according to physical laws is referred to as "loop flow" or parallel path, which is generally defined "as the difference between scheduled and actual flow of electricity over a given established transfer path."<sup>144</sup> Consequently, if FERC were to order the owner of the line between A and B to provide "contract path" service and recover the applicable rate, then other owners of interconnected lines over which some of the power actually flows will incur costs but receive no compensation.

On the assumption that parallel flows and the resulting power losses "aggregated to a small number owing to reciprocal arrangements between [interconnected] utilities," the occurrence of parallel paths or loop flows has been largely ignored in the past and "contract path" has been the basis for selling transmission services among utilities.<sup>145</sup> As transmission service becomes widely available and utilities focus increasingly on their transmission operations, they can be expected to seek compensation on the basis of actual flows.

The challenge to regulators is to ensure that these legitimate demands are accommodated correctly. The occurrence of parallel path does not increase the total cost of providing the transmission (assuming all costs are correctly

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144. Richard S. Bayless, *Planning Aspects of Phase Shifters in the Western Interconnection 1* (1992) (unpublished manuscript, on file with the *Yale Journal on Regulation*). Control error may also cause actual flows "at particular instants [to] differ from hourly schedules," but these are not considered to be "loop flows." *Id.* at 1-2; see N.W. Simons et al., *Quantification of the Economic Consequences of Loop Flows*, 229 (presented at Electric Utility Consultants, Electric Systems Planning and Operations Conference, 1992) [hereinafter *Economic Consequences*].

145. *Economic Consequences*, *supra* note 144, at 231. Two commentators have referred to loop flows as "externalities" that, in the past, have been internalized by reason of the traditional vertical integration of the electric utility industry. Douglas Gegax & Kenneth Nowotny, *Competition and the Electric Utility Industry*, 10 *YALE J. ON REG.* 63, 72-76 (1993). These commentators argue that internalization will become impossible in a market open to competitive entry, and the result will be increased coordination and transaction costs. *Id.* at 73.

accounted for, whether under FERC's pricing model or any other form of pricing); consequently, the price paid for transmission service should not increase. The solution to the parallel path problem is not changing the price, but rather correctly allocating the transmission payments to the owners of transmission capacity affected by a wheeling service.

## 2. *Modifying or Terminating Wheeling Orders*

Under the "escape hatches" discussed earlier in this Article,<sup>146</sup> the EAct relieves transmitting utilities from the obligation to provide service in specified circumstances where transmission capacity is constrained. There is a tension among FERC's new authority to order a transmitting utility to enlarge capacity,<sup>147</sup> the authority of states over the siting and construction of transmission capacity,<sup>148</sup> and FPA section 211(d),<sup>149</sup> which authorizes FERC to modify or terminate a mandatory transmission obligation once excess capacity ceases to be excess. Absent a resolution of this tension in a way that narrowly construes the avenues for voiding transmission obligations, emergence of a competitive wholesale power market could be jeopardized.

### a. *Good Faith Effort to Enlarge System*

Although the EAct squarely grants FERC the authority to order an enlargement where needed to accommodate a transmission request, the Act also lifts the enlargement obligation whenever the transmitting utility, after "a good faith effort," has failed to obtain the necessary approvals or property rights under applicable federal, state, and local laws.<sup>150</sup> Rep. Moorhead (R-CA) explained in a floor statement that "good faith effort" should be interpreted to require the transmitting utility to act as diligently as it would if it were seeking the approval to accommodate its own capacity requirements.<sup>151</sup> It is critical to the effective functioning of this new market that FERC take a hard look at the first utility requests for such relief from a transmission order, scrutinizing the diligence of the utility, and authorizing termination only in rare instances where enlargement is truly impossible. Making such a determination is likely to require the participation of representatives of affected state agencies possessing siting and licensing jurisdiction. While FERC cannot compel states to intervene and participate, it can adopt a policy of granting affected states automatic intervention in proceedings and applications for transmission service.

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146. See *supra* text accompanying notes 62-63.

147. EAct § 721 (amending FPA § 211(a)) (to be codified at 16 U.S.C. § 824j(a)).

148. See *supra* note 35 and accompanying text.

149. 16 U.S.C. § 824j(d)(1)(B) (1988); see *supra* text accompanying notes 62-63.

150. EAct § 721 (amending FPA § 211(d)(1)(C)) (to be codified at 16 U.S.C. § 824j(d)(1)(C)).

151. 138 CONG. REC. H11,438 (daily ed. Oct. 8, 1992).

*b. Termination of Transmission Orders*

The new law preserves the pre-existing limitation on a transmitting utility's obligation to provide mandatory wheeling service. Specifically, section 211(d) requires FERC to terminate a transmission order upon finding that capacity that was in "excess" (i.e., more than that needed to provide service to the transmitting utility's own customers) at the time the order was issued is no longer excess.<sup>152</sup> Termination cannot be ordered, however, if the service is provided under the terms of an unexpired contract between the parties or if alternative procedures for termination are provided by contract. Although these termination provisions have been in place since 1978, FERC has never had occasion to interpret or apply them because it has never issued a transmission order under PURPA's 1978 amendments to the FPA. FERC could ease the market's concern about the uncertainty associated with possible termination of a transmission service by offering some guidance on how these provisions will be applied.

Of particular value would be an early and clear ruling that FERC will address termination requests by transmitting utilities in light of FERC's new authority to compel a transmitting utility to enlarge capacity. In other words, FERC should make terminations under section 211(d) contingent upon a showing by the requesting transmitting utility that not only is once-excess capacity no longer excess, but also that expansion is impossible under the "good faith" standard of FPA section 211(d)(1)(C). Where expansion or economical demand management is possible, terminations should not be available.

In addition, FERC should make clear that use of excess capacity for interruptible service or economy transactions does not render that capacity "no longer excess" for purposes of seeking to terminate firm wheeling service provided pursuant to a mandatory transmission order.

*B. Planning and Coordinating Transmission Systems*

Early in the evolution of the EPAct's transmission access provisions, the Department of Energy and industry groups urged lawmakers to address the inevitability that an increase in the number of persons using transmission services will necessitate greater planning and coordination of the nation's various transmission systems.<sup>153</sup> Coordination of FERC's new authority to

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152. 16 U.S.C. § 824j(d)(1)(B) (1988).

153. See Letter from Energy Secretary James D. Watkins to Representative Phil Sharp (D-IN) (Sept. 27, 1991) (on file with the *Yale Journal on Regulation*). Planning and coordination among segmented owners of transmission has been a priority of Federal regulators since the early 1960s. See FEDERAL POWER COMM'N, NATIONAL POWER SURVEY 3-5 (1964).

order wheeling with the exclusive authority of states over siting and constructing transmission facilities was also identified as a serious potential impediment to expanded transmission access. Although, the legislation is silent on transmission planning and coordination, and does not adequately rationalize the segmented jurisdictions of FERC and the states,<sup>154</sup> FERC and state regulators appear ready to tackle these issues.

There was immediate and widespread recognition of the need for increased planning and coordination. Representatives of virtually all participants in the market—privately-owned and publicly-owned utilities, electric cooperatives, QFs, would-be EWGs, and residential and industrial electricity consumers—struggled for months, into the waning hours of the 102d Congress, to devise a broadly-supported provision authorizing regional transmission groups (RTGs) to engage in planning and coordination. Their last-minute product, which came to be known as the “Consensus RTG proposal,” arrived too late for acceptance by the lawmakers.<sup>155</sup> FERC, however, was quick to embrace the concept. FERC promptly requested public comment on the Consensus RTG and stated its intention to issue a notice of proposed rulemaking that would include at least the “essential elements” of the Consensus RTG.<sup>156</sup>

### 1. *Consensus RTG Proposal*

A regional transmission group would be a regional organization, organized under a FERC-approved charter, formed to plan and coordinate the use of transmission facilities. Membership would be open to any person that could seek or be subject to a wheeling order under the new law—transmission owners, wholesale purchasers, and wholesale generators. The virtue of an RTG would be that planning and coordination could be undertaken cooperatively by those having an interest in, and an understanding of, the region’s interconnected transmission systems. By contrast, planning and coordination in the absence

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154. The new law addresses this concern, without solving it, by requiring FERC to modify or terminate any wheeling orders that require construction of new transmission facilities for which state approval cannot be obtained. EPAAct § 721(5)(D) (adding FPA § 211(d)(1)(C)) (to be codified at 16 U.S.C. § 824j(d)(1)(C)).

155. Although not in the EPAAct, the Consensus RTG proposal was placed in the public record. 138 CONG. REC. S17,616, S17,620-22 (daily ed. Oct. 8, 1992). The impressive array of industry interests—including the Edison Electric Institute, the National Rural Electric Cooperative Association, the American Public Power Association, various independent power producers, and environmental and consumer groups—endorsed the Consensus RTG.

156. Request for Public Comments on Regional Transmission Group Proposal, 57 Fed. Reg. 54,580 (Nov. 19, 1992) [hereinafter Consensus RTG]. The 96 comments that FERC received in response to the notice suggest that the sobriquet “consensus” was either premature or ironic. A majority of commentators opposed or sought major modifications to the Consensus RTG. Of the 24 state and local regulatory commentators, most opposed the Consensus RTG outright, and none supported it without major modifications. See David W. Penn, Summary Analysis of RTG Comments to FERC (Feb. 12, 1993) (prepared for the American Public Power Association) (on file with the *Yale Journal on Regulation*).

of an RTG will be undertaken on a piece-meal basis in reaction to individual FERC wheeling orders issued under the new law.

Under the Consensus RTG, FERC would be authorized to approve an RTG if it found:

- a. the "governing agreement" is "just and reasonable" and "not unduly preferential or discriminatory";
- b. the RTG is of sufficient size and scope;
- c. it permits membership by any person who could seek, or be subject to, a wheeling order under new section 211;
- d. it obliges members to provide transmission service to other members and to enlarge capacity as needed, but not to adopt specific planning (i.e., dispatch or construction) prescriptions of the group;
- e. it requires members to coordinate planning;
- f. it ensures due process and fair representation in decision making and dispute resolution among members; and
- g. it ensures that transmission rates, terms, and charges conform to the requirements of sections 205, 206, and new 212 of the Federal Power Act.

## 2. *Role of States*

The role that state regulators might play in connection with the formation and operation of an RTG is not entirely clear. Indeed, there are only two references to state regulators in the Consensus RTG proposal.<sup>157</sup>

First, FERC would be barred from certifying an RTG "if each state commission that has retail rate jurisdiction over RTG members in the region files a notice of disapproval" of the relevant RTG.<sup>158</sup> In other words, only unanimous opposition would defeat FERC certification. Second, the Consensus RTG contains a non-preemption clause that would provide that FERC certification of an RTG "shall not affect State siting, environmental or utility regulatory authority that could otherwise lawfully be exercised over members of such RTG."<sup>159</sup> While a single state cannot veto certification of a multistate RTG, it nevertheless could stymie its operation by exercising retained authority over transmission line siting (and related environmental issues) in a parochial manner that defeats larger regional interests in efficiency and reliability.<sup>160</sup>

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157. This alone may explain the near unanimous opposition that state regulators expressed to FERC in comments on the Consensus RTG. See *supra* note 156.

158. Consensus RTG, *supra* note 156, § 216(a)(3). The Consensus RTG was drafted as a new section 216 to the FPA.

159. *Id.* § 216(d).

160. Elsewhere, the Consensus RTG recognizes that member electric utilities could be prevented by state regulators from implementing planning decisions of the group, and accordingly, members are not bound to accept planning decisions of the group. Their rejection of any planning decision will not relieve that member of its obligation to provide transmission service or enlarge capacity. *Id.* § 216(a)(3); see *generally*

If RTGs are to be effective in attaining regional coordination of generation and transmission resources, they will probably need to incorporate, or be accompanied by, parallel groupings of regulators from the states covered by a certified region. Indeed, the state regulators are increasingly urging establishment of regional mechanisms for siting decisions that have multistate impacts. In its proposed rulemaking on RTGs, FERC should consider using its authority under FPA section 209 to allow<sup>161</sup> (or possibly require) regulators from states covered by multistate RTGs to form into multistate regulatory boards or other decision-making bodies to coordinate regional regulation with planning and coordination undertaken by RTG members.

### 3. Role of FERC

Regardless of whether FERC pursues the Consensus RTG proposal or some other approach to regional planning and coordination, the paramount objective must be planning and coordination by all who own, use, or otherwise depend on a region's transmission system. To the extent that decision-making within the RTG is fair and provides representation to all interests and needs, FERC should consider according significant autonomy and deference to RTG decisions pertaining to planning and coordination of service.<sup>162</sup> At the same time, however, the existence of an RTG or similar planning and coordination body should not result in any lessening of regulation of transmission as a continuing natural monopoly. Regulating transmission rates and the allocation of capacity (whether made part of a planning group's charter or not) will remain necessary.

### C. EWG and Purchased Power Issues

The entry of EWGs vying for position in wholesale power markets will present many procedural issues for federal and state regulators. For instance, in implementing the new law's EWG provisions, FERC will need to develop appropriate EWG application and determination procedures, and state

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Robert S. Simon, "A New Power": Strategies for Working With the Community in Siting and Operating Facilities (presented at the Cogeneration and Independent Power Market Conference, March 1993).

161. See 16 U.S.C. § 824h (1988).

162. The Consensus RTG proposal would empower FERC, on motion or *sua sponte*, to investigate actions by the RTG or its members and to set aside or remand to the RTG any such actions that are in violation of the RTG's governing agreement or applicable FPA requirements. In exercising this oversight, the Consensus RTG proposal would require FERC to "accord substantial deference" to "decisions rendered on an adequate record by an independent arbitrator in accordance with [a FERC-certified] Governing Agreement and a dispute resolution procedure that assures due process for members." 57 Fed. Reg. 54,581 (Nov. 19, 1992). To the extent that the arbitrated decisions resolve factual issues involving system capacity and efficiency, the extent of FERC's deference should be constrained only by the legal requirement that FERC decisions be based on substantial evidence. 16 U.S.C. § 825i (1988).

commissions will need to consider how to exercise their authority over spin-offs and affiliate transactions.

More generally, regulators must address two critical issues affecting the bulk power market. First, FERC will need to develop analytical procedures for determining when to permit EWGs and other wholesale power generators to sell electricity at market-based (as opposed to cost-of-service) rates. Second, states must consider the "general evaluations" concerning power purchases before they permit long-term purchases of power from EWGs and other wholesale power vendors.

### 1. *Market-Based Rates for Wholesale Power*

The new law, particularly its transmission access and affiliate transaction provisions, should greatly influence how FERC analyzes and rules on applications to sell wholesale power at market-based prices in lieu of selling at traditional cost-based rates.<sup>163</sup> Indeed, a measure of the new law's success will be the extent to which it creates a wholesale power market characterized by many price-taking sellers, few if any of whom retain power to influence price. In that scenario, market-based pricing for purchased power could become the norm and FERC-determined cost-based rates the exception.

EWGs can be expected to seek FERC authority to sell the power that they produce at market-based rates. In the past, FERC has permitted power wholesales at market-based rates only where FERC has determined that the seller—electric utilities as well as non-utility generators—either lacked power to influence price in the relevant market or had mitigated that power in some fashion.<sup>164</sup> The most likely forms of market power identified in FERC's market-based pricing precedents<sup>165</sup> are (1) dominance in the power generation in the relevant market,<sup>166</sup> (2) ownership or control of transmission facilities,<sup>167</sup> and (3) affiliation with an electric utility possessing a franchise

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163. FERC initially proposed to permit independent power producers authority to sell wholesale power at market based rates in a 1988 proposed rulemaking. 53 Fed. Reg. 9,327 (Mar. 22, 1988). As defined in the proposed rule, a market-based rate would be a rate established through either competitive bidding or negotiation subject to a price ceiling. See IPP Proposal, *supra* note 15, at 32,103, 32,108-09. No final rule was issued.

164. See *supra* note 45. The most common mitigation measure imposed has been requiring the provision of transmission service by a utility applicant or the utility affiliated with the applicant. FERC has also imposed transmission requirements to mitigate market power in connection with utility merger/consolidation applications. See *supra* note 46.

165. See Bernard Tenenbaum & J.S. Henderson, *The History of Market-Based Pricing*, ELEC. J., Dec. 1991, at 30, 31 [hereinafter *Market-Based Pricing*].

166. See Nevada Sun Peak Ltd. Partnership, 54 F.E.R.C. ¶ 61,264, at 61,769-70 (1991).

167. E.g., Citizens Power & Light Corp., 48 F.E.R.C. ¶ 61,210, at 61,777 (1989) ("most likely route to market power in today's electric utility industry lies in ownership or control of transmission facilities").

distribution monopoly.<sup>168</sup> Predictably, under these analyses of a seller's market power, non-utility sellers are much more likely to receive authority to use market-based pricing than are electric utilities and electric utility affiliates.

In no current or currently foreseeable market do generators that are neither utilities nor utility affiliates possess generation dominance, ownership or control of transmission, or any type of a monopoly franchise. Consequently, under FERC's analysis, these generators should routinely receive authority to wholesale at market based rates.<sup>169</sup>

Extension of similar authority to wholesale sales by utilities or their affiliated EWGs will continue to require case-by-case FERC analysis. In those analyses, FERC could more fully achieve the new law's objective of a competitive wholesale power market by expanding its narrow analysis of a seller's possession or lack of market power to a broader inquiry into the competitiveness of the market into which market-price power is proposed to be sold.<sup>170</sup> Moreover, even if workably competitive wholesale power markets emerge, sales between utilities and EWG affiliates within those markets are likely to continue to require heightened scrutiny to the extent that states do not exercise their authority to prohibit such affiliate sales.<sup>171</sup> FERC can effectively exercise this scrutiny pursuant to its new authority to invalidate the rates and charges that EWGs charge for power to the extent those rates and charges result from any undue preference or advantage received from an affiliate electric utility.<sup>172</sup>

#### a. *Transmission as a Prerequisite*

Although the new law holds out the promise of making FERC ordered transmission available to all wholesale generators at fair rates, the market power of transmitting utilities will not disappear overnight. Individual wheeling orders

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168. Boston Edison Co. *Re: Edgar Elec. Energy*, 55 F.E.R.C. ¶ 61,382, at 61,167 (1991); TECO Power Servs. Corp., 52 F.E.R.C. ¶ 61,191, at 61,697-700 (1990); Terra Comfort Corp., 52 F.E.R.C. ¶ 61,241, at 61,836-37 (1990); *see* TECO Power, 52 F.E.R.C. at 61,701-03 (Trabandt, Comm'r, concurring) (urges finding affiliate dealings at market rates to be unduly preferential).

169. *Market-Based Pricing*, *supra* note 165, at 42 ("When an applicant can demonstrate a lack of transmission market power and no affiliate preference, market-based pricing can be easily approved").

170. Bernard Tenenbaum and J.S. Henderson of FERC's Office of Economic Policy explain that FERC has pursued the narrower analysis of seller market power because it is more administratively convenient than ascertaining whether the market is workably competitive. *Market-Based Pricing*, *supra* note 165, at 38. They acknowledge that "[t]he fact that one seller lacks market power does not imply that each of the other sellers in this market also lacks market power" or that the market is free of barriers to entry. *Id.* Nevertheless, they argue that one "good" application should not be denied "because of market imperfections beyond the control of the applicant." *Id.* This reasoning is extensively criticized as falling far short of FERC's responsibility to protect ratepayers under the FPA. *See* American Public Power Association, A Critical Look at the Federal Energy Regulatory Commission's Market-Pricing Policies for Wholesale Power (Nov. 1992) [hereinafter Critical Look].

171. *See supra* Part II.B.3.a.

172. *See supra* Part II.B.3.b.

under FERC's new authority will not ensure that all potential competitors within a market are able to obtain market access on equal terms. Only after a significant volume of wheeling service is ordered or voluntarily provided will practice and precedent reveal a complete package of prices, terms, and conditions for transmission service on a utility's system. At that point, the transmitting utility will either have a generally applicable transmission tariff on file or will have a *de facto* transmission tariff arising from the transmission services that it is providing on a case-by-case basis.<sup>173</sup> Until that time, however, market power arising from ownership or control of transmission facilities should continue to be a factor in determining the availability of market-based rates within markets where that power can be exercised.

*b. Prerequisite Protections Against Abuse of Affiliation*

FERC has rejected many market-based pricing requests where the applicant was a utility affiliate<sup>174</sup> and can be expected to do so under the new EPAct. Affiliation with a utility can confer on the affiliate market power that undermines competition and should dictate against market-based pricing.

Cross subsidies, in which a utility provides capital or services to an affiliate power producer at prices below market value, are a typical abuse of affiliation. If the affiliate's power sales were thereafter priced on a cost basis, cross subsidization would not be profitable. At market prices, however, the affiliate power producer's unregulated profit margin would increase in proportion to the subsidies it received from its utility parent and that utility's ratepayers. Shareholders would benefit unfairly at the expense of both ratepayers and competing generators.

Exclusionary utility practices can also be used to favor affiliates who generate power within or close to the utility's service territory. For example, a generator that sells power to an affiliated utility may be able to inflate its profit margin to the extent that its affiliated utility purchaser provides it with preferential access to key, and not-infrequently scarce, power production inputs—including transmission facilities, real estate for siting generation facilities, or fuel held under long-term contracts—and denies those inputs to competing sellers on equal terms.<sup>175</sup> By so excluding competitors from

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173. Given FPA requirements that prohibit public utilities from discriminating in the provision of transmission service, 16 U.S.C. § 824d(b) (1988), the rates, terms and conditions negotiated for individual transmission customers will necessarily result in a menu of rates, terms and conditions of access available to all eligible transmission users.

174. *E.g.*, *Edgar Elec. Energy Co.*, 55 F.E.R.C. ¶ 61,382, at 62,167-70 (1991); *Nevada Sun Peak Ltd. Partnership*, 54 F.E.R.C. ¶ 61,264, at 61,769 (1991).

175. *TECO Power*, 52 F.E.R.C. at 61,697; *Edgar Elec.*, 55 F.E.R.C. at 62,167 n.56. Arguably, a utility violates the non-discrimination requirements of the FPA by excluding any power generator from services provided to an affiliate. See 16 U.S.C. § 824d(b) (1988); *TECO Power*, 52 F.E.R.C. at 61,836. Nevertheless, the incentives may be great and detection and proof are ordinarily very difficult.

necessary assets, the affiliate utility can increase the profitability of its affiliate power producer.

With respect to EWGs, the new law empowers both FERC and state regulators to police these abuses. Under new PUHCA section 32(k), states can preclude affiliate transactions altogether by declining to make the five prerequisite findings needed to override the federal prohibition on affiliate transactions with EWGs. Even when the state does make these findings, FERC can still prevent an EWG's sales to an affiliated utility by disapproving its rates and charges on the ground that they result from the receipt of an undue preference or advantage from an electric utility affiliate.<sup>176</sup>

*c. Need to Monitor Market Power*

Many of the arguments advanced in support of transmission access and PUHCA reform focused on the growth of non-utility wholesale power competitors (primarily QFs) during the 1980s. If freed from PUHCA and provided market access equal to that of transmitting utilities, those generators could contest the generation market dominance of the electric utilities, which in turn is a FERC prerequisite to market-based pricing. Whether the experience of the 1980s will continue, however, is uncertain and should be monitored by FERC as it acts on applications to charge market-based rates for wholesale power.

While the 1980s were characterized by a national market "awash with baseload capacity and in need of peaking capacity,"<sup>177</sup> by year 2000 new, large baseload capacity will likely be needed. Unlike the typically smaller capacity constructed by QFs during the 1980s, baseload capacity is significantly more costly and often requires longer lead times. Many question whether non-utility developers, who traditionally rely on short-term project financing, will be able to obtain access to sufficient capital to finance large baseload capacity in competition with utilities and their affiliates.<sup>178</sup> If these commentators are correct, the already apparent trend of utility affiliates acquiring unaffiliated generators<sup>179</sup> will be hastened, and ultimately "a few entities, most of whom will be unregulated affiliates of major electric utilities, will dominate the

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176. EPA Act § 724 (adding new FPA § 214) (to be codified at 16 U.S.C. § 824m)).

177. Critical Look, *supra* note 170, at 13. While there are a number of distinguishing characteristics between baseload and peaking capacity, for purposes of this discussion the most significant distinction is that, relatively, baseload capacity has high capital costs and low operating costs. Consequently, baseload units require a substantial up-front capital investment. Peaking units, by contrast, have relatively high operating costs, which are incurred over time when there is a revenue stream from power sales. This distinction finds exception in high-efficiency combined cycle gas technology that, in recent years, has dramatically lowered the capital costs of gas-fired base-load capacity in certain markets.

178. *Id.* at 12-15.

179. See D.W. Penn, *The Electricity Industry in the 1990's—Public Service or Commercial Operator*, 16-19 (World Electricity Conference, Nov. 9, 1992) (on file with the *Yale Journal on Regulation*).

independent power producer market."<sup>180</sup> In such a market, the opportunities for abusive affiliate transactions and reciprocal preferences between utilities and their power producing affiliate would be rife, and there could be little justification for market-based pricing.

## 2. State Evaluations of Purchased Power

The EAct amends PURPA to require states to decide whether it is appropriate and consistent with state law to conduct "general evaluations" of four issues before allowing or requiring utilities to enter long-term wholesale power contracts.<sup>181</sup> These evaluations, particularly the evaluations into (a) the effect of purchased power on a utility's cost of capital and (b) whether purchased power approvals should be conditioned on "a reasonable assurance of fuel supply adequacy,"<sup>182</sup> should not be undertaken in isolation, but rather should be addressed in the context of state or region-wide integrated resource plans. These evaluations will produce meaningful information only in the context of the overall resource choices made by the specific utility.

In assessing the effect of the fixed capacity payment obligations on a purchasing utility's cost of capital,<sup>183</sup> states should also consider the risk shifting benefits resulting from power purchase contracts. While purchased power may increase a utility's financial risk because it adds a contract obligation contingent upon performance,<sup>184</sup> the decision to purchase power also shifts construction risk and most operating risks away from the utility to the seller.<sup>185</sup> As one commentator has observed, looking only to a power purchase

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180. ELEC. UTIL. WK, Oct. 12, 1992, at 11 (quoting Del Hock, Chief Executive Officer of Public Service Co. of Colorado).

181. EAct § 712 (adding PURPA § 111(d)(10)) (to be codified at 16 U.S.C. § 2621(d)(10)).

182. *Id.*; see *supra* notes 131-35, and accompanying text.

183. Evaluation of whether project-financed QFs and EWGs are over-leveraged is hardly worth the effort. Over time, project-financed generating plants ordinarily carry lower levels of average debt (under 50%) than conventional utility financing (approximately 60%). This is because the non-utility generators are ordinarily forced to pay this debt off within 12 to 17 years. In contrast, utilities use debt instruments that routinely have 30- to 35-year maturities, and issues new debt as old debt is retired, resulting in relatively constant levels of debt. See R.F. Naill & W.C. Dudley, *IPP Leveraged Financing*, PUB. UTIL. FORT., Jan. 15, 1992, at 15, 16.

184. The contention of some utility analysts that a power purchase agreement should be treated as debt is suspect. "While purchase contracts contain many debt characteristics, the obligations are unique . . . . The take-and-pay component does not constitute a guaranteed fixed payment stream and results in some risk sharing." Fitch Investors Service, Inc., *Purchased Power Benefits and Risks 3* (Mar. 8, 1993) [hereinafter *Purchased Power*] (on file with the *Yale Journal on Regulation*). By contrast, debt is an absolute obligation to pay a sum at a specific time. Payments under most power sales are liabilities contingent on power being delivered. Under most purchased power agreements, the obligation to make capacity payments ratchets down in proportion to reductions in the seller's performance. For example, if a seller fails to achieve a specified level of performance (e.g., 80% of contracted capacity, excluding allowed outages) a purchaser's payment may decrease five or more percent for every percent of reduced power. See E.P. Kahn, *Risks in Independent Power Contracts: An Empirical Survey*, ELEC. J., Nov. 1991, at 33-34 [hereinafter *Empirical Survey*].

185. See generally *Empirical Survey*, *supra* note 184, at 30-32; *New Offensive*, *supra* note 134.

to determine the effect of the purchase on a utility's bond rating and, in turn, on the purchasing utility's cost of capital, is tantamount to saying that

the War Between the States was fought because a South Carolina regiment fired cannons at Fort Sumpter. It entirely misses the point. It is inappropriate to compare the credit rating of a utility before and after the purchase from the [non-utility generator] . . . .

The appropriate comparison is one between buying capacity versus building the capacity.<sup>186</sup>

In other words, the risks of buying must be weighed against all of the risks of building and operating, including the risk that state regulators will disallow all or part of an investment in new generating capacity.<sup>187</sup>

A comprehensive evaluation of all risks and how they are affected when utilities "build" or "buy" will likely conclude that there is an optimal balance between purchased power and utility generation that each utility should strive for.<sup>188</sup> Some states have already established a target mix of utility generation and power purchases. For example, Florida has set 30% of total capacity as the optimal level for purchased power by the utilities that the state regulates.

#### Conclusion

Throughout the years of legislative debate on both PUHCA reform and expanded transmission access, many lawmakers and industry participants urged caution. In their view, the existing structure of the nation's electric power system provided reliable service. If it isn't broken, they argued, don't fix it. Ultimately, however, the various forces of change united and overcame this opposition. What ultimately united those forces was the growing evidence that wholesale power markets had significant potential for competition, which was stymied not by immutable market conditions, but rather by the regulatory obstacles of PUHCA and the lack of legal remedies to challenge utility domination of transmission access. Those regulatory and legal obstacles no longer stand in the way of would-be competitors in wholesale power markets.

The combination of EWG status and FERC authority to compel nondiscriminatory transmission access will almost certainly stimulate wholesale power competition in the short run. Whether that competition can be sustained in the longer run is less certain. Perhaps the greatest threat to a long-term competitive

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186. *New Offensive*, *supra* note 134, at 4.

187. *See supra* notes 16-17 and accompanying text.

188. For example, the Fitch Investors Service has concluded that "[a]s a general rule, purchased power contracts accounting for up to 20% of a utility's total generation are acceptable." *Purchased Power*, *supra* note 184, at 2.

power market is that the number of viable EWG competitors may decline, and the remaining few may affiliate with, and become dominated by, electric utility companies. As explained in this Article, there is some evidence that this is already happening. Toward the end of this decade, as the demand for large, costly baseload capacity increases, will a sufficient number of EWG competitors be able to carry the long construction lead times and financing requirements of baseload capacity? If regulators fail to recognize that competitive EWGs have significantly different financial structures than electric utilities with monopoly distribution franchises, they will weaken EWGs as viable competitors in the long term.

Abusive affiliate transactions between utilities and affiliate EWGs also pose a major threat to the long-term competitive potential of the new wholesale power markets. The new law provides both state regulators and FERC with potent powers to police these abuses—state regulators have a veto power over affiliate transactions that are unmanageable or otherwise contrary to the interests of ratepayers, while FERC is awarded a *de facto* veto power in its authority to rule unlawful the rates or charges for EWG power whenever those rates or charges result from undue preferences or advantages that the EWG receives from an electric utility affiliate. Notwithstanding these powers, detection of affiliate abuses, which are often subtle and well camouflaged, will require vigilant oversight by regulators, consumers, and other competitors.

Finally, and perhaps most importantly, potential wholesale power competitors can compete only if they can deliver power to markets. FERC's new authority to order transmission is only a first step. The challenge now is to ensure that the Nation's transmission systems are not operated as Balkanized power centers, but as mutually dependent, interconnected grids. While it is understandable that Congress declined to legislate on issues of regional coordination and planning, its failure to do so makes immediate the need for FERC and state regulators, together with transmission owners and users, to devise regional bodies with authority to plan, coordinate, and operate transmission systems in a manner that is fair and maximizes regional efficiency and reasonable compensation. Creation of such bodies, together with the adoption of transmission rates that effectively track the costs of transmission and compensate the transmission owners whose systems are actually affected by a transmission service, will go a long way toward ensuring that transmission services will be provided fairly and voluntarily. FERC's new authority to order transmission would then serve only as a backstop.

PUHCA reform and transmission access, in short, simply removed regulatory and legal barriers to a competitive wholesale power market. Nurturing that market will require new structures, new thinking, and new approaches to decision-making by the power industry and its regulators.