

INTRODUCING COMPETITION INTO THE ELECTRIC UTILITY INDUSTRY: AN ECONOMIC APPRAISAL

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I. INTRODUCTION

In the last decade, a number of articles have been written calling for greater reliance on competition in the electric utility industry and less regulation as a means of insuring desirable performance. Two fundamentally different approaches to this goal have been offered. The first would require a substantial restructuring of the industry, together with deregulation of some elements. Specifically, it has been suggested that vertical disintegration of the industry could result in sufficient competition among independent generation companies to substitute for regulation at the bulk power level. The achievement of such restructuring would require federal legislation mandating the vertical and horizontal disintegration of the industry, providing for the transfer of billions of dollars of electric utility assets to separate companies, dealing with the associated income shifts, and preempting a large portion of state regulatory authority. The restructuring mandated by the Public Utility Holding Company Act of 1935 required 30 years to implement. The restructuring envisioned today by the proponents of deregulation is equally drastic. Therefore, it seems unrealistic to expect this approach to have a near-term effect on the industry. In light of that, we leave an analysis of restructuring the industry and its potential impacts to another time and another paper.

As a second approach, many authors have urged that greater emphasis can and should be placed on modifying the behavior of utilities within the present industry structure in order to promote competition as a supplement to regulation. These arguments for spurring greater competition without structural change have not gone unnoticed. During the last 10 years public policy has encouraged competition in the electric utility industry in a number of ways. This paper concentrates on the desirability of this movement toward greater competition within the framework of the present industry structure. Our aim is to examine how public policy has been applied and where it is headed, and then to assess whether that policy movement is economically justified. Specifically, have technological or market changes opened up competitive opportunities in this industry that regulators can encourage by pressing for changes in firm behavior? How likely is it that conduct changes introduced in pursuit of competitive goals will produce the correct economic signals to result in a more efficient industry?

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As economists both authors have testified on many of the issues covered by this article. We are indebted to our colleagues at NERA and to numerous industry experts who shared with us their knowledge and experience and provided valuable advice in the preparation of this paper. We, however, are solely responsible for the opinions expressed and for any remaining errors or omissions.

It is not unfair to say that the analyses which have been done to date concentrate on whether more "competitors" could be created—generally, whether more individual firms could obtain ownership interest in a given activity or at a particular level of the business—given the authors' views of economies of scale and economies of vertical integration. If more entities could be created, it is assumed that the performance of the industry would improve relative to that yielded by what the authors see as a stifling regulatory environment. We grant that it is almost always "feasible" to introduce more competition into any situation. Laws can be changed, conduct can be modified and the structure of the industry can be altered so as to stimulate competitive processes. The meaningful question to address, however, is not what is feasible, but what is desirable. Whether creating more entities would introduce more competition, defined in some realistic sense, whether the competitive market envisioned could function without major changes being made in the regulations imposed on the industry, and whether the net outcome of these changes would benefit consumers are questions not adequately addressed. In short, an all-too-frequent analytical obtuseness characterizes the intellectual underpinnings of competitive proposals and policies—namely, the practical difficulties of the present situation (regulation and the problem of inducing dynamic efficiency) are compared with the ideal view of the alternative (that if more competition can be introduced, it will lead to enhanced efficiency).

The remainder of this paper is divided into five sections. Section II describes the present structure and regulation of the electric utility industry. Section III describes the trend in public policy toward promoting competition among electric utilities. Section IV summarizes the literature calling for more competition and describes the kinds of actual or potential competition we will be addressing. Section V then presents a detailed consideration of possible forms of competition, given the present regulatory framework and structural characteristics of the industry.¹ Our aim is to be comprehensive—that is, to consider every kind of competition that has been discussed by critics of the present structure and behavior of the electric utility industry. We focus on the real efficiency effects that would be associated with each type of competition and on how the distribution of benefits among various utilities and consumers would change. Finally, in Section VI, a summary of our conclusions is presented.

In brief, we find that if competition is to be a constructive force in this industry, it must be accompanied by major policy revisions and at least some structural reforms.² A broad-brush public policy of pursuing more competition within the present structural and regulatory framework, on balance, is likely to produce more costs than benefits. In particular, the regulatory policy of basing utility prices on average embedded costs, the subsidies and preferences

¹Specifically, in Section V, we accept as given retail and wholesale rate of return regulation, the present state of vertical and horizontal integration in the industry, and the subsidy received by publicly owned and cooperative utilities.

²This is not an endorsement of a currently popular position in favor of substantial restructuring and deregulation of the industry as a means of promoting competition. Indeed, our preliminary analysis of that alternative points to a large number of specific problems. See, for example, Joe D. Pace, "Deregulating Electric Generations: An Economist's Perspective," before the International Association of Energy Economists, Houston, Texas, November 1981.

available to publicly owned and cooperative utilities, and the physical characteristics of electric utilities combine to increase the costs and reduce the benefits of competition.

II. THE STRUCTURE AND REGULATION OF THE INDUSTRY

The present structure of the electric utility industry provides an appropriate springboard into our discussion of the role which competition can play. This industry is characterized by considerable diversity. There is diversity in firm ownership, firm size, the degree of horizontal and vertical integration, the technologies and resources employed and in the extent of regulation. In this introductory section we present a brief sketch of this diversity. In later sections we will show how this diversity presents both the basis for competition and limits its potential effectiveness.

Originally, the electric utility industry consisted of isolated plants generating power to be distributed over small localized areas. Service areas were limited in size by the short distances over which electricity could be distributed economically. The development of alternating current transmission extended the distance over which power could be economically transported, allowing individual plants to be connected together into systems under common ownership.

Economic factors inherent in the industry encouraged the development of relatively large vertically and horizontally integrated utilities, as well as the coordination of activities among electric utilities. These inherent characteristics of the industry are the need for (1) integrated load planning,³ (2) coordinated operation of generation and transmission facilities, and (3) coordinated planning of generation and transmission facilities.

To match generating resources efficiently to customer demands requires the integration of loads in a number of communities—that is, the tying together into a single power supply network of a large group of customers so that their electricity needs may be planned for and met jointly. This is true for several reasons. First, the timing of individual customers' peak demands and their patterns of consumption throughout the day or year will vary. The wider the geographic area covered, the more diverse are likely to be the loads of individual customers or communities. Given this, at any point in time, service can be rendered jointly to a number of customers throughout a large area with significantly less generating capacity than would be required to meet the sum of their individual demands. Second, forecasts of future loads will tend to be more reliable when a large number of customers located in communities with differing economic bases are planned for jointly. In many instances, utilities responded to these incentives by expanding to a large enough scale to capture the economies of load diversity internally. In other cases, smaller utilities have sought to achieve such economies by coordinating load planning with neighboring systems.

³Load can be defined as the amount of electric power required at any specified point or points on a system. The simultaneous needs for electric power of the system's customers determine the load which the system must meet and for which it must provide the required generating and transmission facilities.

Coordinated operation and planning of facilities are required by both the physics and the economics of power production and transmission. The laws of physics tie together all transmission and generation facilities connected to a single power supply network. Unless generating units with sufficient capacity to meet ever changing loads are connected at all times by adequate transmission, the system will fail. Moreover, electricity will flow instantaneously from surplus to deficit areas making the operation and reliability of the elements of a network interdependent. Unless generating units are dispatched in order of their incremental running costs, enormous real economic savings are foregone; thus, the laws of economics require coordination.

Approximately 3,400 electric systems operate in the United States today.⁴ These systems are owned by private investors, agencies of the federal government, agencies of state governments, municipalities and cooperatives. While a precise legal description of each ownership arrangement is beyond the scope of this paper, a brief review of the principal forms is useful.

A. *Investor-Owned Utilities*

Although investor-owned utilities comprise less than 7 percent of all electric systems operating in the United States, they own the majority of electric generation capacity and serve the majority of retail electric load. As of 1979, investor-owned utilities owned approximately 78 percent of all generation capacity and made 77 percent of all retail sales.⁵

Among the investor-owned utilities, there is considerable diversity in size and structure. In size, they vary from multibillion dollar individual utilities and holding companies to very small entities that serve a single town or industrial operation.⁶ Most of the large investor-owned utilities are vertically integrated in that they generate, transmit and distribute electric power and energy, and are horizontally integrated in that they serve geographic areas encompassing hundreds of communities. The degree of vertical integration, varies significantly, however, among investor-owned utilities.⁷

A few examples illustrate the diversity of investor-owned utilities. Whereas the subsidiaries of the American Electric Power Company generate virtually all of the power they sell, Green Mountain Power Corporation depends on others for more than 90 percent of its requirements.⁸ Most of the generation capacity of the Houston Lighting and Power Company is fueled by natural gas, whereas Pennsylvania Power and Light Company depends primarily on coal-fired capacity, and Public Service Electric and Gas Company and Commonwealth Edison Company depend, respectively, on oil and nuclear capacity

⁴American Public Power Association, "Electric Utility Statistics," *Public Power*, Vol. 39, No. 1, January-February 1981, at D-2.

⁵Edison Electric Institute, *Statistical Year Book of the Electric Utility Industry/1980*, at 23, 45.

⁶In 1980, the total assets of the five largest investor-owned utility systems averaged \$10.3 billion. The five smallest of the top 100 privately owned electric systems had average assets of \$210 million. Derived from *Moody's Public Utility Manual*, 1981.

⁷Fifteen of the largest 100 investor-owned utilities do not own sufficient generation capacity to meet their own peak demands. "The Top 100 Electric Utilities 1980 Operating Performance," *Electric Light and Power*, Vol. 59, No. 8, August 1981, at 19.

⁸*Electrical World Directory of Electric Utilities* (New York: McGraw-Hill, 1981), 1981-1982 edition, at 605, 807.

for large shares of their generation.⁹ The Southern Company has assets of nearly \$11.5 billion and generating capacity of well over 22 billion kilowatts, while the Vermont Marble Company has assets of under \$2 million and capacity of under 10,000 kilowatts.¹⁰

B. Federal Systems

Six federal agencies market power produced by federal projects. Five of these agencies, known as Power Marketing Administrations (PMAs),¹¹ were created specifically for the purpose of marketing and transmitting power generated by hydroelectric facilities installed at federal multipurpose water projects.¹² The primary purpose of these projects was navigation and flood control; hydroelectric facilities were installed to capture the energy produced by falling water. The PMAs only market power; they do not construct, operate or maintain generation facilities. The hydroelectric facilities are constructed and operated by the U.S. Army Corps of Engineers and the U.S. Bureau of Reclamation. PMAs are required by law to give preference to public bodies and co-operatives for the sale of their electricity.¹³

The Tennessee Valley Authority (TVA) is the sixth federal agency that markets federally produced power. TVA was established in 1933 to develop the resources of the Tennessee River Basin. Until the early 1950s, TVA, like the PMAs, marketed power only from hydroelectric facilities constructed as part of navigation and flood control projects in the basin area.¹⁴ When economical hydroelectric sites were exhausted in the 1950s, TVA was authorized to construct a comprehensive power production system, including fossil-fueled and nuclear generation facilities. It is now a predominantly steam-generating system, with hydroelectric generation accounting for only 17.3 percent of total generation.¹⁵

TVA is the largest electric system in the country. It generates and transmits electric power to serve an area of about 80,000 square miles, including parts of seven states.¹⁶ TVA accounts for 5.6 percent of national electricity generation. For the first 20 years of its existence, TVA obtained capital from direct Congressional appropriations. Since 1959, its power program has been self-financing. In recent years, TVA has financed projects by borrowing from the Federal Financing Bank at interest rates one-eighth of a percentage point above the U.S. Treasury borrowing rate.

⁹Edison Electric Institute, *Power Directory 1981: An Environmental Directory of U.S. Steam Electric Power Plants*, "Power Plants," Sec. 1.

¹⁰*Uniform Statistical Report—Year Ended December 31, 1980 for The Southern Company and Subsidiaries*, at 9, 20; *Electrical World*, supra note 8, at 808; Letter of January 7, 1982 from C. A. Rogers, Vermont Marble Company.

¹¹For a more complete description, see the *Annual Reports* published by the U.S. Department of Energy for the Alaska Power Administration, Bonneville Power Administration, Southeastern Power Administration, Southwestern Power Administration, and Western Area Power Administration.

¹²BPA also enters into "net billing arrangements" with public and cooperative utilities that own thermal capacity through which they market that power as well.

¹³16 U.S.C. § 825s. This section also requires that power from federal projects be disposed of in such a manner as to encourage the most widespread use thereof, at the lowest possible rates to consumers, consistent with sound business principles.

¹⁴From its inception, TVA did operate a small steam plant at Muscle Shoals which had been constructed as part of a munitions operations during World War I.

¹⁵Tennessee Valley Authority, *Power Program Summary*, Vol. I, 1980, at 5.

¹⁶*Id.*, Vol. II, 1980, at 1.

TVA, like the other federal systems, is required to give preference to public bodies and cooperatives for sales of its electricity. TVA's power is sold to 160 municipal and cooperative utilities and one small investor-owned utility for distribution to approximately 2.8 million customers. TVA also supplies power directly to 50 industrial customers, as well as to a number of federal projects.¹⁷

Technically speaking, no federal agency is fully vertically integrated; only TVA and Bonneville Power Administration (BPA) make any direct sales that are classified as retail. In practice, however, the TVA system is fully vertically integrated. With one small exception, all TVA distributors are municipal or cooperative entities and all receive their power from TVA under 20-year, full-requirements contracts. In addition to supplying wholesale power, TVA specifies the retail rates charged by distributors, sets accounting standards to be followed, sets the terms and conditions under which service is provided to individual retail customers, and restricts the use of profits from electric operations.

Federal power agencies are not subject to federal income taxes. Federal projects also generally are exempt from state and local taxes but do make some payments in lieu of taxes. Whereas state and local taxes amounted to 4.24 percent of investor-owned net utility plant in service in 1979, payments in lieu of such taxes amounted to only 2.66 percent of TVA's net plant and only 0.03 percent of the PMAs' net plant.¹⁸

C. Cooperative Systems

In 1936, legislation was passed establishing the Rural Electrification Administration (REA) as a lending agency to finance distribution systems which would provide electricity to consumers in rural areas that did not have central station service. In most cases, those areas were so sparsely settled and anticipated usage was so limited that distribution costs would have been prohibitively high for private utilities. The REA's function was to make available loans at subsidized interest rates to promote the construction of distribution systems in these low-density areas. Preference for such loans was given by the 1936 Act to cooperatives and public agencies. The REA currently provides distribution loans to cooperatives at interest rates of 5 to 7 percent (depending on the density of the area served). In 1980, there were 985 active REA borrowers serving a total of nine million customers. Sales were 147 million megawatt-hours and revenues were approximately \$6.5 billion. REA borrowers generated 38.2 percent of their own power in 1980 and purchased 28.9 percent from investor-owned utilities, 21.9 percent from federal agencies and 11.0 percent from other public agencies.¹⁹

To achieve the economies of scale associated with large power plants, many REA borrowers have organized generation and transmission cooperatives (G&Ts). G&Ts are separate nonprofit organizations, owned and con-

¹⁷*Id.*, Vol. I, 1980, at inside cover.

¹⁸Joe D. Pace, "Tax Losses Associated with the Construction of Electric Generating Plants by Government-Owned and Cooperative Electric Utilities," Working Paper, March 1981.

¹⁹U.S. Department of Agriculture, Rural Electrification Administration, *42nd Annual Report of Energy Purchased by REA Borrowers*, 1980, at 5; and *1980 Statistical Report, Rural Electric Borrowers*, at x. xiii.

trolled by member distribution cooperatives, which have the responsibility for providing bulk power supply to members. Historically, loans at 2 to 5 percent have been available to finance transmission and generation facilities of cooperatives. Currently, however, the REA generally makes loans for G&T facilities through the Federal Financing Bank at interest rates reflecting the government's current cost of money, plus one-eighth of 1 percent. G&Ts and some distribution cooperatives have also received REA loan guarantees in order to finance purchase of ownership shares in investor-owned utilities' large coal and nuclear generating plants. REA cooperatives are nonprofit and therefore do not pay federal income taxes or, in most cases, state income taxes. However, in some states they pay state and local property taxes and may also pay gross receipts and sales taxes.

D. *Nonfederal Public Systems*

This category of electric utilities includes municipal, county and public utility districts, and state power agencies. In 1979, 2,206 local public power systems served about 12.4 million customers. These systems had 55,516 megawatts of installed capacity and sold 260,418 megawatt-hours to ultimate customers. Approximately two-thirds of the nonfederal public systems provided distribution service alone and purchased all their power at wholesale from other suppliers.²⁰ The Power Authority of the State of New York (PASNY) is the largest of the nonfederal public power systems. In 1979, PASNY's total generating capacity was 6,902 megawatts, sales amounted to 41,286,490 megawatt-hours and total revenues were \$674,549,211.²¹

Rising costs of purchased power, inability to finance and construct large efficient-size plants individually, and the exhaustion of federal preference power in some areas of the country have led recently to the formation of municipal joint action agencies. More than half of local public power systems now participate in some joint action (pooling of financial resources by two or more utilities to meet their electric load demand). Today, 51 joint action agencies exist in 31 states.²² Joint action agencies frequently engage in central planning for all members and may engage directly in generating plant construction and operation programs, or may purchase portions of plants built by other utilities. The purpose of the joint action agencies is to enable local public power systems to achieve potential economies of scale available from large generating plant facilities and from the diversity of broad-based customer loads.

Municipal systems and state power authorities enjoy substantial financial advantages not available to investor-owned utilities. They are exempt from federal income taxes. Most also are exempt from state and local taxes, but may make payments in lieu of local taxes. In 1979, state and local utilities

²⁰American Public Power Association, *supra* note 4.

²¹U.S. Department of Energy, *Statistics of Publicly Owned Electric Utilities in the United States—1979*, December 1980, at 51-52.

²²Larry Hobart, "Joint Action — Where is it Going?" *Public Power*, Vol. 39, No. 5, September-October 1981, at 56-57.

paid an amount equal to less than 1 percent of average net electric plant in service in state and local taxes and tax equivalents as compared to 4.24 percent for investor-owned utilities.²³ In addition, state and municipal electric agencies can obtain relatively low-cost financing through issuing bonds with interest payments exempt from federal (and some state) income taxes.

E. Coordination Among Electric Utilities

Power pools are an important feature of the industry's structure. Through them the various types of utilities coordinate among themselves and with each other.²⁴ Power pools can be loosely defined as interconnections between two or more utilities for two-way exchange of power. All types of utilities participate in power pools. The nature of individual pools is determined by the needs and capabilities of participants. Pooling agreements may provide one or more of the following services: (a) emergency support; (b) economy interchange or central economic dispatch; (c) coordinated maintenance; (d) reserve sharing; (e) diversity exchange; (f) joint planning; and (g) joint participation in ownership of generating units.²⁵ Even this list is not a complete enumeration of services that may be included in pooling agreements.

Pooling agreements vary substantially in degree of formality. Agreements range from informal *ad hoc* arrangements between interconnected contiguous utilities to highly structured and comprehensive arrangements such as the New England Power Pool (NEPOOL) and the Pennsylvania-New Jersey-Maryland Interconnection Agreement.²⁶ Pools usually are governed by contracts that delineate responsibilities of the parties and define the functions to be performed and the prices to be charged for various services. All pool agreements, to a greater or lesser extent, entail some loss of autonomy for each participant. At the most structured end of the range, a pool agreement

²³Pace, *supra* note 18, at 15-16.

²⁴For recent detailed assessments of power pooling, see: Federal Energy Regulatory Commission, Office of Electric Power Regulation, *Power Pooling in the South Central Region; Power Pooling in the Northeast Region; Power Pooling in the North Central Region; Power Pooling in the Western Region; Power Pooling in the Southeast Region*, 1980-1981.

²⁵(a) Emergency support was the first form of pooling. Interconnections were developed strictly for emergency use, the circuit being closed only when emergencies or maintenance shutdowns required its use. We discuss this type of transaction at Sec. V-C.

(b) Economy interchange is an arrangement assigning power demands to generating units that are in operation below capacity, depending on the incremental operating costs at each unit and the cost of power lost in transmission, so that demand is met at the lowest total operating cost.

(c) Coordinated maintenance refers to agreements that allow for staggered shutdowns of generating units for periodic maintenance work. This type of arrangement limits the need for additional capacity to prevent service interruptions.

(d) Reserve sharing is an arrangement that enables interconnected utilities to reduce capacity reserves that would otherwise be necessary to ensure service in the event of equipment failure. In essence, transmission facilities are substituted for duplicative generating facilities to maintain adequate safety reserves as the probability of unexpected equipment failure is distributed among a larger number of units.

(e) Diversity exchange agreements allow interconnected utilities to benefit from divergent peak demand characteristics of their loads, resulting in lower overall capacity needs for participants. Summer peaking systems would make excess capacity available to winter peaking systems in the winter and the reverse would be true in the summer.

(f) Joint planning refers to coordination of load growth and management plans for the future among the participating utilities.

(g) Joint participation in units allows utilities that individually could not realize scale economies of generation units, but together have sufficient demand and financial capacity to finance and jointly own large units that are extremely capital intensive but have lower per unit operating costs.

²⁶*Power Pooling in the Northeast Region*, *supra* note 24.

can result in management of participating firms as though they are a single generation system, leaving only financial affairs, rates and distribution facilities under individual company control. At the other extreme are pools in which each member maintains almost complete autonomy except for transactions with its neighbors, agreed to on an *ad hoc* basis.²⁷ Successful pools depend upon the perceived existence of a mutuality of benefits as well as an equitable sharing of costs and responsibilities among the members.

After the 1965 major blackout in the Northeast, the need for greater coordination in the electric utility industry became widely recognized. As a result, reliability councils were formed by electric utilities throughout the United States and parts of Canada as voluntary associations to coordinate the reliability aspects of electric systems, such as the level of spinning reserves, relay settings and evaluation of transmission line capabilities. Members also exchange plans for future generation and transmission facilities. The North American Electric Reliability Council (NERC) was formed in 1968 to augment the reliability and adequacy of bulk power supply in North America. NERC consists of nine regional reliability councils and includes virtually all power systems with more than 25 megawatts of generating capacity in the United States, and Canadian systems in Ontario, British Columbia, Manitoba, New Brunswick and Alberta.²⁸ These councils, as voluntary associations, do not act as agencies of federal, state or local governments. All operations of the Councils are financed by assessments on utility members.²⁹ NERC provides a forum for coordinating planning of future generation and transmission facilities and the current operation of interconnected systems.

F. Trends Among Ownership Types

Until recently, there had been only minor shifts in the relative importance of the various types of utilities. Federal system sales and generation had declined somewhat in relative significance as the sites for hydroelectric facilities marketed by those agencies grew more scarce. As Table I shows, this decline was offset to a significant degree by the growth of cooperatives.

There are indications, however, that significant shifts in the relative positions of various types of utilities are under way. In particular, local government-owned and cooperative utility capacity is projected to expand more rapidly in the near future. Whereas these utilities built 21 percent of the total industry's capacity in the last decade, they are projected to own 31 percent of the capacity slated to come into service during the coming decade. The cooperative share is growing most rapidly, with these systems planning capacity additions between 1980 and 1989 at twice the rate of the previous 10-year period.³⁰ This increasing ownership role, combined with rapidly escalating generating plant costs, will result in a fourfold increase in generating plant investment by government-owned and cooperative utilities by 1990.

²⁷Until recently Texas Interconnected Systems was close to this end of the spectrum.

²⁸National Electric Reliability Council, *1980 Summary of Projected Peak Demand, Generating Capability, and Fossil Fuel Requirements for the Regional Reliability Councils of NERC*, July 1980, at 4-5. NERC became the North American Electric Reliability Council in September of 1981.

²⁹U.S. Department of Energy, *Electric Power Supply and Demand for the Contiguous United States 1980-1989*, July 1980 at Appendix A.

³⁰Pace, *supra* note 18, at 11.

TABLE I
PERCENTAGE OF TOTAL KILOWATT GENERATION CAPACITY AND
KILOWATT-HOUR SALES TO ULTIMATE CONSUMERS
BY TYPE OF UTILITY

Utility Ownership	1965		1975		1980 ¹		Estimated 1980-1989
	Capacity	Sales	Capacity	Sales	Capacity	Sales	Capacity
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
State and Local	9.5%	10.9%	8.4%	9.0%	7.3%	7.7%	14.1%
Cooperative	1.0	4.4	1.6	6.4	2.9	7.3	9.0
Federal	13.6	6.3	9.6	4.4	8.8	3.5	7.9
Investor	76.0	78.4	80.4	80.2	81.0	81.5	69.0
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

¹Data for state, local and federal systems are for 1979.

Source: *Statistics of Publicly Owned Electric Utilities in the United States*, 1965, 1975, 1979.
Rural Electric Borrowers Annual Statistical Report, U.S. Dept. of Agriculture, Rural Electrification Administration, 1965, 1975, 1980.
Statistics of Privately Owned Electric Utilities in the United States, 1965, 1975, 1980.
Statistical Year Book of the Electric Utility Industry, Edison Electric Institute, 1979.
 Joe D. Pace, "Tax Losses Associated with the Construction of Electric Generating Plants by Government-Owned and Cooperative Electric Utilities," Working Paper, March 1981.

G. Regulation

Regulation of the electric utility industry began early in its history as a result of public desire to obtain the economies associated with the production of electricity by monopoly enterprises and, at the same time, assure that the consumer was not exploited by those monopolies. Today, electric utility regulation is vested in a number of state and federal agencies.

1. State Regulation

State utility commissions have long been established in virtually every state to regulate the service, rates of return, and retail rate structures of investor-owned utilities operating within their jurisdictional areas. No state commission exercises authority over federal electric power facilities, only 16 have been authorized to control the rates of local publicly owned systems, and only 25 have such authority over cooperative systems.³¹ Regulated rates are generally based on the average embedded costs of providing service.³² While operating costs are determined on a current basis (either those experienced in a recent period, adjusted for known changes, or those projected for the next year), capital charges (depreciation, interest and return on investment) generally are based on the book value of the firm's facilities, which at the present time may be only a fraction of their replacement cost. In most, if not all cases during the past decade, the revenues derived from rates based on average costs have not been high enough to cover the long-run marginal costs of meeting additional demand.

State public utility commissions also typically regulate the construction and siting of generation and transmission facilities, accounting procedures, security issues, safety, adequacy of service, initiation and termination of service and allocate the territories utilities may serve. Some states have broadened their commissions' power to include environmental regulation of electric power facilities.³³

³¹U.S. Department of Energy, *The National Power Grid Study: Final Report*, Vol. 1, January 1980, at 20.

³²A primary activity of both federal and state authorities is rate regulation. Although there are some differences, commissions on both government levels follow similar procedures.

First, a commission must establish a total revenue requirement. This involves determining the expenses that are to be recognized and establishing an allowed rate of return on the net investment of the utility, otherwise known as the rate base. The rate of return must be just and reasonable, permitting the utility to provide reliable service while receiving a fair return on its investment. Once the total revenue requirement is determined, the commission must formulate a structure for rates to produce required revenues. By statute, the design must be nondiscriminatory. Commissions follow this broad methodology but differ in their methods for determining rate base and cost recovery.

Whereas rates charged for wholesale sales to municipal and cooperative systems are generally made at prices based on average costs, transactions among large utilities are often permitted to take place at negotiated rates. These rates are sometimes based on splitting the difference between the incremental and decremental costs of the parties, especially for short-term economy sales. Longer term transactions may be based on the cost of power from specified units or at a negotiated rate based on the expected additional costs of the supplying utility. These transactions are more often reflective of short-term or long-term incremental costs than are sales at average cost based wholesale rates. See Sec. V-A for a more detailed discussion of how wholesale power rates are determined.

³³*National Power Grid Study*, *supra* note 31.

2. Federal Regulation

At the federal level, numerous agencies have regulatory responsibility over electric utilities.³⁴ The Federal Energy Regulatory Commission (FERC) has regulatory control over the wholesale rates of investor-owned utilities and over rates for federally produced power marketed by the PMAs. The FERC also regulates power pooling, wheeling and interconnections among utilities. Through the hydroelectric licensing process, the FERC and the Corps of Engineers exercise significant control over hydroelectric plants in the interests of navigation, flood control, recreation and other public purposes. The REA exercises limited control over cooperative utilities by placing conditions on its loans to these systems, although it generally does not regulate either rates or the terms and conditions of service. The Securities and Exchange Commission (SEC) regulates the corporate structure of utilities and the financing of holding companies and affiliates under the Public Utility Holding Company Act of 1935. The Departments of Interior and Agriculture regulate the placement of private transmission lines on federal property. The Nuclear Regulatory Commission (NRC) regulates the construction and operation of all nuclear reactors, regardless of type of ownership. The NRC also may condition construction and operating licenses for nuclear units to eliminate any situation it finds inconsistent with the policies underlying the antitrust laws. The Environmental Protection Agency issues performance standards for air and water pollution control of existing and new generating facilities.

The above listing demonstrates the diversity of authorities regulating the electric utility industry at different levels of government. On a general level, federal authorities are responsible for regulation of activities among utilities while state authorities oversee activities of utilities relating to ultimate customers.

III. PUBLIC POLICY TOWARD COMPETITION

The promotion of competition among electric utilities as an alternative or supplement to regulation is not a new idea but a revival of an old one.³⁵ In the early days of the industry, cities frequently granted directly competitive franchises. However, by the 1920s, recognition of the natural monopoly nature of electric distribution, economies of scale in generation, and improvements in transmission technology had led, with few exceptions, to the demise of direct duplicative competition and the rise of regulatory commissions to limit the exercise of monopoly power. Although duplicative competition became rare, publicly owned electric companies were promoted as valuable yardsticks against which the performance of private regulated utilities could be compared. Competition by example was an often-cited rationale for the formation of TVA, PASNY and other public power projects.

³⁴For a more complete description of the federal agencies' regulatory responsibilities see: 16 U.S.C. § 824(d) and § 797(c) (FERC); 7 U.S.C. § 901-904 (REA); 15 U.S.C. § 79-79z (SEC); 16 U.S.C. § 472.551 (Department of Agriculture and Department of Interior); and 42 U.S.C. § 2135 (NRC).

³⁵For an historical treatment of the role of competition, with particular emphasis on the role of government, see: Richard Hellman, *Government Competition in the Electric Utility Industry: A Theoretical and Empirical Study* (New York: Praeger Publishers, 1972).

Direct competition between utilities, however, remained very much the exception. Competitive concerns generally were traded off for the greater efficiency of large integrated utilities, and coordination rather than competition was viewed as the proper focus of policy. The protection of the integrity of service areas was recognized as a desirable goal by the TVA, the REA and numerous states. Successive *National Power Surveys* published by the Federal Power Commission (FPC) emphasized the desirability of utilities coordinating their operations with each other to promote efficiency. Many, if not most, utility executives and their attorneys believed that the regulated nature of the business protected most of their rates and policies from antitrust scrutiny. The FERC and, to some extent, the SEC resisted considering competition as part of their regulatory process.

The drift of public policy back toward the promotion of competition is a growing and pervasive phenomenon. In recent years, the federal courts have consistently ruled that the regulatory agencies, such as the SEC and the FERC, must consider antitrust implications when determining whether any license or rate application is in the public interest.³⁶ The courts, in addition, have held that the actions of utilities are often subject to the antitrust laws.³⁷ With its creation in 1974, the NRC assumed the responsibility previously charged to the Atomic Energy Commission of considering the effects on competition in deciding on licenses for nuclear plants.³⁸ Congress recently has expressed its view on at least two important issues relating to competition among utilities.³⁹ These bodies, taken together, have moved substantially in the direction of promoting increased competition among electric utilities.

We illustrate this movement below by discussing evolving policies toward the provision of transmission services (wheeling), the availability of tariffs, the relationship between wholesale and retail rates (price squeeze), entry into power pools, and access to large generation units by small systems (unit access). The following sections highlight these developments as they relate to a number of specific issues that have substantial competitive overtones. Our discussion of these developments in the law and its interpretation is intended to provide only a general indication of the policies that seem to be emerging and is in no way intended to provide a detailed analysis of the many complex nuances contained in various laws, regulations and judicial decisions. Footnotes are used liberally to refer the reader to specific sources for more detailed treatment.⁴⁰

³⁶See, e.g., *Atlantic Seaboard Corp. v. FPC*, 404 F.2d 1268, 1272 (D.C. Circuit 1968); *Northern Natural Gas Company v. FPC*, 399 F.2d 953 (D.C. Circuit 1968); *City of Huntingburg, Indiana v. FPC*, 498 F.2d 778, 783 (D.C. Circuit 1974); *Gulf States Utilities v. FPC*, 411 U.S. 747 (1973); *Central Power and Light Co. v. FERC*, 575 F.2d 937 (D.C. Circuit 1978) certiorari denied 99 S. Ct. 568; *Public Systems, et al. v. FERC*, 606 F.2d 973 (D.C. Circuit 1979); *Central Iowa Cooperative v. FERC*, 606 F.2d 1156 (D.C. Circuit 1979); *Vermont Yankee Nuclear Power Corporation, et al.*, 43 SEC 693 (1968).

³⁷See, e.g., *Otter Tail Power Company v. United States*, 410 U.S. 366, 93 S. Ct. 1022 (1973); *City of Mishawaka v. American Electric Power Company, Inc.*, 616 F.2d 976 (7th Circuit 1980); *United States v. Florida Power and Light Company*, 1971 Trade Case § 73,637 (M.D. Fla.); *City of Newark v. Delmarva Power and Light Co.*, 467 F.Supp. 763 (D. Del. 1979); *Town of Massena v. Niagara Mohawk Power Corp.*, 1980-2 Trade Case § 63,526 (N.D. N.Y. 1980); *West Texas Utilities Co. v. Texas Electric Service Co.*, 470 F.Supp. 798 (N.D. Tex. 1979); and *Borough of Lansdale v. Philadelphia Electric Company*, 1981-2 Trade Case § 64,218.

³⁸42 U.S.C. § 2135(c), Atomic Energy Act.

³⁹These two issues relate to wheeling and preference rights to federal hydroelectric facilities. See: Public Utility Regulatory Policies Act, 16 U.S.C. § 824, 92 Stat. 3136 (1978); Pacific Northwest Electric Power Planning and Conservation Act of 1980, Pub. L. 96-501, 94 Stat. 2697.

⁴⁰The authors of this paper are not attorneys and none of the statements herein are intended to convey legal conclusions. We have freely summarized and condensed the discussion of many complex cases and issues in an attempt to convey the general thrust of policy. The cases cited represent only a small fraction of the total number dealing with these issues.

A. Wheeling

The provision of transmission service to enable one electric supplier to receive power from a remote source using the lines of an intervening utility (wheeling) has the effect of expanding the economic options available to utilities for power supply since it allows the purchaser to obtain power from nonadjacent sources without the necessity of constructing its own transmission facilities to that point. The economic literature advocating greater competition among electric utilities is close to unanimous in advocating wheeling as an essential element of the competitive process. This theoretical emphasis has been mirrored by litigation before both courts and regulatory commissions.

The courts have made it clear that under the antitrust laws, one utility may be required to negotiate for wheeling with another system when it possesses monopoly power over transmission alternatives.⁴¹ On the other hand, a utility may refuse to wheel under the terms and conditions desired by a purchaser if those terms and conditions are unreasonable.⁴² The utility may also refuse to wheel if it does not have monopoly power.⁴³ The courts have also ruled that while the FERC has the obligation to consider antitrust issues in deciding public interest questions involving wheeling, it does not have the right to make utilities common carriers, since this would violate the expressed will of Congress that wheeling be voluntary except in limited cases.⁴⁴ All of these generalizations are based on cases involving very specific sets of circumstances and therefore provide limited general guidance as to when utilities must make transmission services available.

The Public Utility Regulatory Policies Act (PURPA) does give the FERC limited power to mandate wheeling and interconnections between utilities, after holding public hearings and finding that certain conditions are met.⁴⁵ The effect on competition is an element of the public interest standard which must be met to determine whether or not wheeling should be ordered under PURPA. However, the FERC may not order a utility to wheel when the result would be the loss of an existing customer or would upset existing competitive relationships. This statutory limitation constrains the ability of the FERC to use its powers to promote shopping by wholesale customers for alternative power supplies. A recent court ruling rejected an attempt by the FERC to exempt cogenerators from formally meeting the statutory requirements for FERC ordered interconnections.⁴⁶

⁴¹*Otter Tail*, supra note 37.

⁴²*Town of Massena*, supra note 37. Specifically, they may refuse to offer a generally available wheeling tariff and insist on reviewing requests for wheeling on a case-by-case basis. See *City of Groton v. Connecticut Light & Power Company* (2d. Cir. 1981) at 22.

⁴³*Borough of Lansdale*, supra note 37. A jury in this proceeding found that the company did not have monopoly power over the transmission alternatives of the plaintiff city.

⁴⁴See: *Sunflower Electric Cooperative v. Kansas Power & Light Company*, 603 F.2d 791 (10th Circuit 1979); *Niagara Mohawk Power Corporation v. FPC*, 538 F.2d 966 (2d. Cir. 1976); *City of Huntingburg, Indiana v. FPC*, 498 F.2d 778 (1974) 162 U.S. App.D.C. 236; *Florida Power and Light Company v. FERC*, 660 F.2d 668 (1981); and *Richmond Power and Light of Richmond, Indiana v. FERC*, 574 F.2d 623 (1978).

⁴⁵16 U.S.C. § 824i, 824j. Specifically, wheeling can be ordered when it is in the public interest, would conserve a significant amount of energy, would significantly promote the efficient use of facilities and resources or improve reliability, and would not impose uncompensated costs or impair reliability. The authority to order wheeling is further constrained in that wheeling cannot be ordered where it would not reasonably preserve existing competitive relationships or result in supplanting service presently provided by the proposed wheeling system under a contract or tariff.

⁴⁶*American Electric Power Service Corporation, et al. v. FERC*, Docket No. 80-1789, slip option (D.D.C., January 22, 1982). This decision also held that the FERC had not met their statutory obligation to fix just and reasonable rates when it required utilities to pay cogenerators for their power at rates equal to the utilities full avoided costs.

The NRC has addressed the wheeling issue in the context of its licensing responsibility to determine whether activities under a proposed license will "...create or maintain a situation inconsistent with the antitrust laws. . . ." ⁴⁷ Under the provisions of the Atomic Energy Act, ⁴⁸ utilities obtaining construction licenses for nuclear power plants are subject to an antitrust review by the Attorney General who recommends to the NRC whether or not a hearing is necessary to determine whether there is a situation inconsistent with the antitrust laws. Most utilities have chosen an informal settlement of competitive issues with the NRC in order to avoid lengthy and costly litigation that could delay their construction plans. Starting with the 1971 license conditions for Florida Power Corporation's Crystal River No. 3 unit, transmission access became a standard part of the agreed upon license conditions for subsequent units. ⁴⁹ In general, the early agreements require the utility (or utilities) constructing the unit to "...facilitate the exchange of bulk power over its system . . .", but require wheeling only to the extent that facilities are available. More recent license conditions, however, are much more comprehensive and require that transmission facilities be expanded if necessary to accommodate requested wheeling services. ⁵⁰

Each of the three NRC review cases in which the liability issue was litigated resulted in similar provisions. The Consumers Power Company's (Midland) conditions were negotiated with the NRC following a decision adverse to the company by the NRC's Atomic Safety and Licensing Appeal Board. Among other things, those license conditions require the filing of a transmission services tariff with the FERC. ⁵¹ The Central Area Power Coordinating Organization (CAPCO) companies' (Davis-Besse and Perry) conditions do not require that a transmission tariff be filed but do require transmission services to be offered. ⁵² The conditions ordered for Alabama Power Company (Farley) also require that transmission services be provided for Alabama Electric Cooperative, Inc., and for any municipally owned system. ⁵³

Most large investor-owned utilities have been subject to the antitrust review of the NRC. ⁵⁴ It has been this body, rather than the courts or the FERC, that has most advanced the policy that wheeling services should be made generally available, especially for municipal and cooperative utilities within or adjacent to the service areas of integrated utilities.

It is fair to conclude that the combined result of the antitrust standards adopted by the courts, the addition of competition to the considerations of the FERC, and the effects of the NRC review process is that wheeling today cannot be unreasonably denied to municipal and cooperative systems that do not maintain their own transmission networks. This is not to imply that there

⁴⁷42 U.S.C. § 2135(c)5, at 1290.

⁴⁸42 U.S.C. § 2135.

⁴⁹Transcomm, Inc., *The Nuclear Regulatory Commission's Antitrust Review Process: An Analysis of the Impacts*, June 1981, at 54.

⁵⁰The Mississippi Power & Light Company's (Grand Gulf) commitments were the first to contain these provisions (in 1973) which subsequently became standard. See *Id.*, at 60.

⁵¹*Id.*, at 64.

⁵²*Id.*, at 64.

⁵³Decision of the Atomic Safety and Licensing Appeals Board, NRC, Alabama Power Company, Docket Nos. 50-348A, 50-364A (June 1981). This decision has been appealed.

⁵⁴The DOJ has reviewed and issued advice letters concerning 92 nuclear unit applications covering "...almost all of the largest utilities in the country." Transcomm, *supra* note 49, at 27.

are no remaining controversies regarding wheeling. Whether transmission should be negotiated on a case-by-case basis or be made generally available,⁵⁵ whether a particular utility has sufficient market power over transmission alternatives to be required to provide service,⁵⁶ whether the requested transmission capacity is available given the actual or potential requirements of the owning utility,⁵⁷ and whether the terms and conditions sought are appropriate⁵⁸ remain areas that are litigated on a case-by-case basis. In general, however, transmission services are increasingly available to utilities wishing to enter into power supply transactions with utilities with which they are not directly connected.⁵⁹

B. *Tariff Availability*

A second aspect of public policy relevant to competition among electric utilities focuses on the availability of wholesale service. Wheeling alone does not provide power supply alternatives. Historically, utilities have limited wholesale sales to customers within or adjacent to their areas of retail service.⁶⁰ Later in this paper we discuss the economic reasons for this limitation. It is, however, clear that any unwillingness of utilities to extend wholesale service limits the options of potential customers. This section outlines the movement of public policy toward requiring that utilities widen the availability of their wholesale tariffs.

The FERC is empowered under Section 202(b) of the Federal Power Act⁶¹ to require utilities to interconnect with each other upon certain findings and an opportunity for hearing. The Commission may order a sale of energy to another utility whether or not an interconnection already exists. Such a sale can be ordered to be either temporary or permanent.⁶² The FERC may also determine the terms and conditions, including the price, governing such a sale. It is, however, important to note that the FERC has no authority under this section to require a utility to increase its generating capacity in order to make such sales.⁶³

The FERC may also exercise its authority to see that tariffs are nondiscriminatory and in the public interest by rejecting proposed tariff limitations or eliminating existing limitations. It has done so in instances where it found that the firm proposing or maintaining the limitation had monopoly power over potential customers.⁶⁴ These rulings have not gone so far as to establish that wholesale tariffs should be generally available, but they have signaled a

⁵⁵*Florida Power and Light Company*, supra note 44.

⁵⁶*Borough of Lansdale*, supra note 37.

⁵⁷A current case involving that issue at the FERC deals with transmission access to the Pacific Intertie. See *Pacific Gas and Electric Company, et al.*, Docket Nos. E-7777 (Phase II) and E-7796.

⁵⁸*Town of Massena*, supra note 37.

⁵⁹At the wholesale level, however, this comes at a time when the interest of utilities in serving additional customers is rapidly diminishing. See our discussion at Sec. V-A.

⁶⁰In our survey of the 20 largest investor-owned systems, accounting for nearly half of investor-owned generation capacity, we found only two instances of wholesale sales to nonadjacent utilities.

⁶¹16 U.S.C. § 824a(b); also, supra note 45.

⁶²*New England Power Company v. FPC*, 349 F.2d 258 (1st Circuit 1965).

⁶³The Commission may not order service if it would require the constructing of generation facilities or impair service to existing customers.

⁶⁴Cf. Opinion No. 57, *Florida Power and Light Company*, Docket Nos. ER78-19 (Phase I) and ER78-81 (1979).

reluctance of the Commission to see wholesale customers treated differently from retail customers.⁶⁵

The general policy the FERC has adopted is perhaps best illustrated in a proceeding involving Florida Power and Light Company in which the Commission stated that:

... where a utility possessing market power in a relevant market seeks to ... impose conditions which foreclose supply options or increase the costs of competitors ... its application for amendment must be rejected and found unjust and unreasonable under Sections 205 and 206 of the Federal Power Act — unless the utility can show that compelling public interests justify the service conditions.⁶⁶

In general, the FERC seems to be moving toward a policy of requiring utilities to make their wholesale tariffs available to customer utilities within the area where they provide retail service. It is not clear whether this obligation will be extended beyond the service area of the supplying utility.⁶⁷ However, the FERC Staff recently has offered testimony arguing that, with some significant limitations, such an extension would be in the public interest.⁶⁸

The NRC has also addressed the availability of wholesale tariffs in its pre-licensing antitrust reviews. One of the provisions agreed to in late 1971 by the Florida Power Corporation (Crystal River No. 3) required it to sell at wholesale to any requesting entity.⁶⁹ Subsequent license conditions generally included an agreement to make firm and partial requirements wholesale service available to neighboring distribution systems.⁷⁰ These conditions, however, do not specify the terms and conditions under which such service is to be offered. It is not clear that such service must be on the same average cost based tariffs under which present customers are being served. In one instance the FERC has ordered a utility to continue to offer wholesale power, priced at average system cost, to a municipal utility in addition to a variety of wheeling and coordinating services provided under a contract negotiated pursuant to the NRC competitive review process.⁷¹

In the litigated NRC cases the outcome has been similar. The Alabama Power Company (Farley) conditions specifically require partial requirements wholesale service.⁷² The Consumers Power Company (Midland) conditions impose an obligation to supply wholesale power to entities that historically

⁶⁵ *City of Winnfield v. Louisiana Power and Light Company*, Order Affirming and Adopting Initial Decision, FERC Docket Nos. ER81-457, EL81-13 (December 11, 1981).

⁶⁶ *Florida Power and Light Company*, supra note 64.

⁶⁷ One proceeding presently before the FERC which raises this issue is *Central Virginia Electric Cooperative v. Appalachian Power Company*, Docket No. EL78-13.

⁶⁸ Direct and Rebuttal Testimony of John A. Hansen in *City of Winnfield v. Louisiana Power and Light Company*, FERC Docket Nos. EL81-13, ER81-457 (September 1981); Direct Testimony of Ralph E. Miller in *Central Virginia Electric Cooperative v. Appalachian Power Company*, FERC Docket No. EL78-13 (1981).

⁶⁹ Transcomm, supra note 49, at 54.

⁷⁰ For example, the Public Service Company of Indiana (Marble Hill Units 1 and 2) agreed that "Licensee will sell power on a full or partial requirements basis to any neighboring distribution system at rates which fully compensate Licensee for its costs." *Federal Register*, Vol. 40, No. 82, Monday, April 28, 1975.

⁷¹ *City of Winnfield v. Louisiana Power and Light Company*, supra note 65. The Commission ruled that the availability of embedded cost wholesale power could not be unilaterally restricted.

⁷² There is, in addition, in the Alabama conditions general language requiring the company to furnish other bulk power services that are "reasonably available" from its system and ordering that the company not adopt "restrictive provisions" in rate filings or contracts which would prevent other systems from fulfilling all or part of their bulk power requirements. See NRC Appeals Board Decision, supra note 53.

have been customers.⁷³ In the CAPCO (Davis-Beese and Perry) proceeding, the final conditions imposed contain general requirements to sell wholesale power similar to those imposed in the cases that settled prior to litigation.⁷⁴ Most recently, an NRC Hearing Board has issued a preliminary decision ordering the applicant to provide wholesale power to entities outside its service area at rates based on embedded costs. This tentative ruling, however, is premised on the judgment that this constitutes reasonable relief where the utility has previously been found guilty of participating in a conspiracy to allocate wholesale markets.⁷⁵

While the general drift of public policy has been in the direction of mandating that utilities offer wholesale service on a more widespread basis, the final disposition of the issue and its effect on competition remain uncertain. To our knowledge, no utility has yet been required to provide embedded cost based wholesale service to customers not within or adjacent to its service territory. However, it seems clear that this issue will be pressed in the near future and its resolution will be of major significance.

C. Price Squeeze

The appropriate relationship between retail and wholesale electric rates has become the focus of policymakers concerned with the possibility that retail competition can be undermined by high wholesale rates. This has been labeled the "price squeeze" area and draws its origins from a frequently cited antitrust case involving the Aluminum Company of America (ALCOA).⁷⁶ The basic issue in ALCOA, and in the recent line of electric utility cases, is whether the vertically integrated supplier allows a differential between its wholesale and retail prices sufficient to cover distribution costs and provide a reasonable profit opportunity for its nonintegrated customers. In addition to the specific importance of this issue to the promotion of competition, the price squeeze issue also has provided the FERC with the opportunity for enunciating important general views toward competition that may be applied in other areas.

The application of the price squeeze concept to electric utility rates initially was resisted by the FERC but subsequently ordered by the courts.⁷⁷ The U.S. Supreme Court held that Section 205(b) of the Federal Power Act, which forbids the maintenance of any unreasonable difference in rates, gives the Commission both the power and the obligation to consider the competitive effects of differences between retail and wholesale rates and the extent to which any anticompetitive effects can be remedied by reductions in the wholesale rate over which it has jurisdiction.

The details of the treatment of price squeeze by the FERC are beyond the scope of this paper. Many complex issues are involved, some of which have been resolved by the Commission and others which remain open. The purpose of this paper will be adequately served by a review of the general policies

⁷³Transcomm, *supra* note 49, at 63-64.

⁷⁴*Id.*, at 63-65.

⁷⁵*Florida Power and Light Company*, Memorandum and Order Concerning Florida Cities' Motion for Summary Disposition on the Merits, NRC Docket No. 50-389A (December 11, 1981).

⁷⁶*Aluminum Company of America v. United States*, 148 F.2d 416 (2d. Cir. 1945).

⁷⁷*FPC v. Conway Corporation*, 426 U.S. 271 (1976) affirming 510 F.2d 1264 (D.C. Cir. 1975).

regarding competition that the Commission has enunciated in dealing with the price squeeze issue. Footnotes provide the reader with guidance to key price squeeze decisions that provide more detailed discussions of specific issues.

A key element in the evolving public policy toward competition among electric utilities is the assumption that competition, or at least the potential for competition, generally exists and is worthy of protection. Very early in its price squeeze deliberations, the FERC made the determination that competition and potential competition are so prevalent among electric utilities that they can be presumed to exist anytime utilities are in geographic proximity to each other, and it is possible that one utility could serve a retail customer that would otherwise have been served by the other. This presumption of competition has since been endorsed in at least one circuit court opinion.⁷⁸

A second significant element in the movement of FERC policy toward the protection of competition was the decision that the intent of the wholesale supplier was not relevant in determining either the existence of a price squeeze or whether a price squeeze, once found, was undue.⁷⁹ The Commission took the position that it is the effect on competition which it is obligated to review and not whether that effect was intended.⁸⁰

The presumption of competition and the elimination of intent as an issue leaves the Commission with only the relative levels of retail and wholesale rates to assess in determining whether or not a price squeeze exists.⁸¹ It has approached this obligation by adopting a general standard that differences in rates must be justified by differences in the cost of service.⁸² Most of the FERC price squeeze decisions have concentrated on the relationship between the retail rate charged to industrial customers and the wholesale rate. The prescription of the remedy for a price squeeze and the related question of the nature of the evidence required to show that discrimination is not undue, have not yet been specified in enough detail to allow conclusions as to the ultimate effect of price squeeze regulation on the level of wholesale rates. The Commission has, however, recognized that its power to remedy price squeeze is limited to reducing the wholesale rate of return to the lower end of the zone of reasonableness.⁸³

⁷⁸*City of Groton v. Connecticut Light & Power Company*, 1981-2 Trade Case § 64,329 (October 13, 1981).

⁷⁹Opinion No. 31, Missouri Power and Light Company, FERC Docket No. ER76-539, "Opinion and Order Modifying Initial Decision" (October 1978), at 9. This means that even an electric utility following a policy of filing retail and wholesale rates intended to become effective at the same time, and bearing a cost-justified relationship to one another, can be subject to having its wholesale rate reduced on price squeeze grounds if the state commission rejects part of its retail rate request.

⁸⁰*Id.*, at 8, 9.

⁸¹This is not at all to minimize the complexity of the task of determining which wholesale rate (the filed rate in effect subject to refund or the rate ultimately determined to be just and reasonable) and which retail rate (i.e., rate to which class of customer and in effect at which point in time) are significant. Equally complex is the issue of what methodology should be used for the comparison (simple comparison of billings, rate of return or transfer price analysis). See following Opinions issued by the FERC for more detailed discussions of these issues: Opinion No. 53, Boston Edison, Docket No. E-8855 (July 31, 1979); Opinion No. 62, Southern California Edison Company, Docket No. ER76-205 (August 22, 1979); *Cities of Bethany Appeals Court Decision*, Docket No. 80-1633 (October 30, 1981); and Opinion No. 63, Commonwealth Edison, Docket Nos. E-9002, ER76-122 (September 14, 1979).

⁸²See especially Commonwealth Edison, *supra* note 81 and Southern California Edison, *supra* note 81.

⁸³See, e.g., Opinion No. 86, Minnesota Power & Light Company, Docket No. ER76-827 (June 24, 1980); Opinion No. 53, Boston Edison Company, *supra* note 81; and Opinion No. 63-A, Commonwealth Edison Company, Docket Nos. E-9022, ER76-122 (November 16, 1979).

Two recent decisions of the Circuit Court of Appeals for the District of Columbia have upheld important aspects of the FERC approach to price squeeze. They confirmed that rate of return comparisons, rather than simple rate comparisons, are an appropriate measure of price squeeze. They also held that the wholesale rate ultimately accepted by the FERC as just and reasonable (but for price squeeze), rather than the filed rate temporarily in effect subject to refund, is an appropriate base with which to compare retail rates.⁸⁴

The courts also have had occasion to consider the price squeeze issue in cases brought under the antitrust laws. The first such case actually to come to trial involved, among other issues, the relative costs of electricity under the wholesale and retail tariffs of the Indiana and Michigan Electric Company. This case involved two principal charges in addition to price squeeze: an alleged threat to terminate wholesale service and an alleged policy of acquiring municipal systems. The Court of Appeals considered these elements as part of a "monopoly broth" and emphasized that, "[t]he price squeeze is only a part of the utility's conduct which as a whole was found to violate the Sherman Act."⁸⁵

Because the court combined its consideration of all the charges, it is difficult to read into the decision a clear enunciation of the standard under which a price squeeze, standing alone, would be found in violation of the Sherman Act.⁸⁶ The court did conclude that: (1) over an extended period of time municipal wholesale customers generally had paid more than they would have as industrial customers; (2) the Company never had adopted a policy of seeking parity between wholesale and retail rates, and when differences arose, it did not seek to eliminate them; (3) the Company had "pancaked" its wholesale rate filings (the practice of filing and putting into effect subject to refund, new rates before the previous filing was fully litigated), with the result that the wholesale rate in effect was always a filed rate requested and not one ultimately found to be just and reasonable; and (4) the Company had offered no evidence to justify the disparity between retail and wholesale rates.⁸⁷ These findings, when considered along with the other charges, were found to violate the Sherman Act. Other significant points in the court's holding were that more than general intent must be established in price squeeze cases, and that specific competitive damages must be established, in lieu of using the difference between wholesale and retail charges as the damage measure.⁸⁸

A second case involving the issue of price squeeze was remanded by the Court of Appeals for the Second Circuit to the District Court for additional findings. The circuit court did indicate, however, that specific evidence of the existence of competition is not required to sustain a price squeeze finding and that a five-month long differential between wholesale and retail rates could be

⁸⁴*Cities of Batavia, et al. v. FERC, Commonwealth Edison Co.*, Docket No. 80-1072, 80-1270 slip opinion (D.D.C., February 9, 1982); *Cities of Bethany, et al. v. FERC*, Docket No. 80-1633 (D.C. Cir. 1981).

⁸⁵*City of Mishawaka*, supra note 37, at 13.

⁸⁶*Id.*, In fact, the Court states that if each aspect of the utility's conduct were considered separately "... we might agree with the utility that no one aspect standing alone is illegal," at 17.

⁸⁷*Id.*, See especially at 10, 14.

⁸⁸*Id.*, See at 14, 22. The Court also held that it would not consider the requested retail rate as the relevant yardstick with which to compare the wholesale rate in effect so as not to provide an incentive to further inflate the level of requested retail rates.

long enough to support a price squeeze claim if the sums involved are substantial.⁸⁹ The courts have not yet dealt with the issue of which retail rate or rates should be compared to the wholesale tariff to establish price squeeze, or defined acceptable cost defenses to justify rate differences.⁹⁰

It is not easy to read the drift of public policy toward alleged price squeezes from the limited rulings of the FERC and the courts. What is clear from these decisions is that differences between wholesale and retail rates adverse to wholesale customers must at least be considered by utilities in their rate policies and justified by cost differences or some other persuasive grounds. A showing of specific intent to injure wholesale customers in their retail business may be necessary under the antitrust laws but not at the FERC. Competition between utilities will generally be assumed by the FERC and perhaps by some courts as well. All of these are indicative of a general tendency to promote competition by protecting wholesale customers. Subsequent cases are necessary to clarify the consequences of this tendency.

D. Pooling

Section 202(a) of the Federal Power Act expresses a clear public policy in favor of pooling among electric utilities in order to achieve efficiencies. However, the possibility of power pools being instruments used not only to enhance the efficiency of the participants but to exclude others from those benefits for anticompetitive purposes has been discussed at length in the literature.⁹¹ It is important to our discussion of public policy toward competition among electric utilities to focus carefully on how policy toward these agreements has evolved.

The courts have consistently ruled that the FERC obligation to review competitive effects explicitly extends to filings related to pooling agreements among electric utilities.⁹² The Commission has used this authority to strike provisions which, in its view, were not in the public interest by virtue of their effect on competition. It has, however, weighed other public interest factors and Congressional policies favoring voluntary interconnections and pooling in declining to alter other pool provisions.⁹³

In one instance, the courts declined to review certain terms of a pooling agreement for possible violation of the antitrust laws since the challenged provisions had already been reviewed for their competitive effect by the FERC and since the Commission's decision had been sustained by the courts.⁹⁴ To

⁸⁹*City of Groton*, supra note 78, at 74,508.

⁹⁰*Id.*, The Groton court did not rule that the rate charged to a specific firm at retail cannot be rejected as the relevant standard solely because there was no evidence of competition for that firm's location or for the location of any similar firm.

⁹¹See Alfred E. Kahn, *The Economics of Regulation: Principals and Institutions*, Vol. 2, Chap. 6 (New York: John Wiley & Sons, 1971), at 314-323.

⁹²See, e.g., *City of Huntingburg, Indiana v. FPC*, 498 F.2d 778 (1974); *Municipalities of Groton, et al. v. FERC*, 587 F.2d 1296 (D.C. Cir. 1978); and *Central Iowa Power Co-op v. FERC*, 606 F.2d 1156, 196 U.S. Appeals D.C. 249. The Federal Power Act provides that "No public utility shall, with respect to any transmission or sale subject to the jurisdiction of the Commission, (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service." Section 205(b), 16 U.S.C. § 824d(b).

⁹³*Municipalities of Groton, et al.*, supra note 92, at 1299, 1301-1303.

⁹⁴*Id.*, at 1298.

our knowledge, there have been no court decisions reviewing pooling agreements on antitrust grounds alone.

The NRC, in its antitrust review process, generally has not imposed license conditions that explicitly require that small systems be admitted into pool membership or that the workings of pooling agreements be modified. In general, however, the license conditions agreed to or imposed require that the services normally associated with pools (i.e., emergency support, wheeling, economy interchange, etc.) be provided by the licensee.⁹⁵

E. Access to Specific Facilities

Another policy issue of considerable relevance to the prospect for electric utility competition is the ability of smaller utilities to obtain access to specific facilities owned or controlled by the government or by their larger and more integrated rivals. The facilities to which access is sought frequently convey to the holder specific financial advantages which, if they are not shared, result in lower costs and rates than those of the excluded systems.

Congress has dealt directly with access to federally owned hydroelectric facilities and indirectly with access to hydroelectric facilities developed by other parties under federal licenses. As indicated earlier, federally owned hydroelectric facilities are covered by a "preference" clause which, in effect, gives municipal and cooperative utilities the right of first refusal to the power produced, with investor-owned utilities eligible to purchase only the surplus power available over the needs of preference customers.⁹⁶

When there is sufficient power from federal projects to meet the needs of preference and nonpreference customers alike, this creates no great problem. However, in the Pacific Northwest, as power demands outstripped the capacity of hydroelectric resources, large differentials between the rates of investor-owned and publicly owned systems developed. This led to the passage of the Pacific Northwest Electric Power Planning and Conservation Act of 1980 which, through a complex procedure of sales and buybacks, allowed investor-owned systems to obtain federal hydroelectric power to serve their residential and rural customers.⁹⁷

In 1920, Congress directed that the authority to grant licenses for non-federal hydroelectric development reside in the (then) newly formed Federal Power Commission.⁹⁸ The Commission was instructed to give preference to states and municipalities in granting licenses. Licenses could be granted for a period of 50 years and most licenses were granted for that period.⁹⁹ As a consequence, a large number of hydroelectric licenses are now coming up for renewal. The present FERC (successor to the FPC) ruled in 1980 that the

⁹⁵Transcomm, *supra* note 49, at 52, 53.

⁹⁶16 U.S.C. § 800(a).

⁹⁷Pub. L. 96-501, 94 Stat. 2697.

⁹⁸16 U.S.C. § 797(e).

⁹⁹16 U.S.C. § 799.

preference provision applies to relicensing as well as to the original license process.¹⁰⁰ This decision has been appealed to the courts. If this position is upheld by the courts, the transfer of a very substantial amount of hydroelectric capacity to public agencies from investor-owned utilities at book values generally far below current replacement costs, plus severance damages, becomes more likely though by no means certain.¹⁰¹

Another area of current policy activity involving preferential access to hydroelectric power involves allocations of PASNY power. Municipal systems are pressing claims at the FERC to a larger share of the available hydropower under the existing arrangements and for still greater shares when contracts with upstate New York industry expire in 1985 and 1990.¹⁰² If they are successful in their efforts, the municipal systems will widen further their cost and rate advantages which already give them rates 50 to 500 percent lower than investor-owned utilities in the state.¹⁰³

Another policy issue that indirectly involves preference power is currently before the FERC. The outcome of this proceeding will determine the right of preference customers in California to use privately owned transmission facilities in order to obtain federally produced electricity from the Pacific Northwest. At issue is control over the use of the limited capacity of the "Pacific Intertie," which is composed of three transmission circuits constructed to exchange capacity and energy between California and the Northwest and to import surplus hydroelectric power.¹⁰⁴

Hydroelectric power and its transmission are not the only focus of policy directed to access to specific facilities. Municipal utilities in Florida are pressing antitrust claims in the courts against Florida Power and Light Company for allegedly monopolizing low-cost nuclear power and low-priced natural gas and demanding that Florida Power and Light Company be required to sell shares in existing facilities.¹⁰⁵ Access to nuclear and, in some instances, other base load generation has also been addressed frequently in proceedings before the NRC. NRC license conditions generally require the licensee(s) of the plant to make available to other utilities in its general area of service access to nuclear units either through sale of a portion of the plant or through unit power sales of the plant's output.¹⁰⁶

It is difficult to summarize public policy toward access to specific facilities since that policy is still evolving. It is clear that there will continue to be

¹⁰⁰Opinion No. 88, Opinion and Order Declaring Municipal Preference Applicable to Hydro-Electric Relicensings, FERC Docket No. EL78-43, *City of Bountiful, Utah v. Utah Power and Light Company*, and *City of Santa Clara, California v. Pacific Gas and Electric Company*. Forty-one investor-owned utilities are represented in this proceeding as well as three cities, a state agency and the American Public Power Association. The preference provision is contained in 16 U.S.C. § 800(a).

¹⁰¹The Commission ruled that Section 14(a) of the Federal Power Act, 16 U.S.C. § 807(a), provides for the acquisition of facilities by states on municipalities upon relicensing at a price equal to net investment plus reasonable damages caused by severance.

¹⁰²*Municipal Electric Utilities Association v. PASNY*, Docket Nos. EL78-24 and EL78-37, Initial Decision of the Presiding Administrative Law Judge (October 22, 1980) Phase I; and Initial Decision Granting Summary Disposition in Part and Denying Summary Disposition in Part (December 10, 1980) Phase II.

¹⁰³PASNY, *A Report to the Governor and the Legislature of the State of New York from the Chairman of the Power Authority: Allocation of Hydroelectric Power* (July 1981), Figure 5 at 11.

¹⁰⁴*Pacific Gas and Electric Company, et al.*, supra note 57.

¹⁰⁵*Lake Worth Liabilities Authority v. Florida Power and Light Company*, Civil Action No. 79-5101-CIV-JLK, U.S. District Court for the Southern District of Florida.

¹⁰⁶Transcomm, supra note 49, at 51, 59.

controversy concerning preferential access to hydroelectric power. Access to transmission facilities and to nuclear units not covered by NRC license conditions is likely to be an issue as well. We will address these policy issues in our discussion of the role of competition in the following sections.

IV. COMPETITION AMONG ELECTRIC UTILITIES

The academic and legal literature frequently has addressed competition among electric utilities. While some authors have advocated a substantial restructuring of the industry to promote competition among independent generation companies, most suggest that more competition is possible even without a significant change in industry structure.¹⁰⁷ The following discussion summarizes the kinds of competition among utilities the latter group of authors envision and reviews some of the changes in utility behavior they recommend.

Much of the discussion in the literature focuses on the potential for competition among generating utilities in supplying bulk power for resale. Fairman and Scott, for example, believe that competition at the wholesale level could become the most important competition among electric utilities.¹⁰⁸ Changes in technology, which have made transmission economic over longer distances, as well as the apparent exhaustion of economies of scale in generation, are often cited as factors making wholesale competition feasible. Meeks, however, suggests that this competitive potential is limited by economies of scale which would limit such a market to a small number of firms in each region. Nonetheless, he sees promotion of that competitive potential as worthwhile.¹⁰⁹

The specific recommendations of these authors for policy changes to increase the prospects for bulk power supply competition include: (1) elimination of territorial restrictions on sales for resale;¹¹⁰ (2) a general requirement

¹⁰⁷The following articles focus largely on industry restructuring: Edward Berlin, Charles J. Cicchetti, and William J. Gillen, "Restructuring the Electric Power Industry," William H. Shaker and Wilbert Steffy, eds., *Electric Power Reform: The Alternatives for Michigan* (Ann Arbor, Michigan: Institute of Science and Technology, University of Michigan, 1976), at 231-235 (hereinafter cited as *Reform*); Matthew Cohen, "Efficiency and Competition in the Electric-Power Industry," *The Yale Law Journal*, Vol. 88, June 1979, at 1511-1549; Philip Fanara, Jr., James E. Suelflow and Roman A. Draba, "Energy and Competition: The Saga of Electric Power," *The Antitrust Bulletin*, Spring 1980, at 125-142; and John H. Landon and David A. Huettner, "Restructuring the Electric Utility Industry: A Modest Proposal," *Reform*, at 217-229.

The following articles suggest some restructuring but also see prospects for greater competition within the present industry structure: David C. Hjelmfelt, "Exclusive Service Territories, Power Pooling and Electric Utility Regulations," *The Federal Bar Journal*, Vol. 38, Winter 1979, at 22; Kahn, *supra* note 91; Robert M. Spann, "Restructuring the Electric Utility Industry: A Framework for Evaluating Public Policy Options in Electric Utilities," *Reform*, at 247-263; and Leonard W. Weiss, "Antitrust in the Electric Power Industry," Almarin Phillips, ed., *Promoting Competition in Regulated Markets*, (Washington, D.C.: The Brookings Institution, 1975), at 136.

The following articles focus largely on promoting competition within the present structure: James F. Fairman and John C. Scott, "Transmission, Power Pools, and Competition in the Electric Utility Industry," *The Hastings Law Journal*, May 1977, at 1159-1207; James E. Meeks, "Concentration in the Electric Power Industry: The Impact of Antitrust Policy," *Columbia Law Review*, January 1972, at 64-130; David W. Penn, James B. Delaney and T. Crawford Honeycutt, *Coordination, Competition and Regulation in the Electric Utility Industry*, NUREG-75/061 (Springfield, Virginia: National Technical Information Service, June 1975); David S. Schwartz, "Pricing and Competition in the Regulated Energy Industries," Harry M. Trebing, ed., *New Dimensions in Public Utility Pricing* (East Lansing, Michigan: Institute of Public Utilities, Michigan State University, 1976), at 555-583; and Harry M. Trebing, "Broadening the Objectives of Public Utility Regulation," *Land Economics*, Vol. 53, February 1977, at 106-122.

¹⁰⁸Fairman and Scott, *supra* note 107, at 1162. See also: Kahn, *supra* note 91, at 318; Penn, et al., *supra* note 107, at 18; Trebing, *supra* note 107, at 120-121; and Weiss, *supra* note 107, at 170.

¹⁰⁹Meeks, *supra* note 107, at 76, 84.

¹¹⁰Meeks, *supra* note 107, at 86, 120, 124-125, and Weiss, *supra* note 107, at 170.

of interconnecting and wheeling;¹¹¹ and (3) encouraging access by small utilities to power pools.¹¹² They conclude that with these alterations in utility behavior, a more competitive, and presumably more efficient, market would emerge.

In their advocacy of increased wholesale competition, the authors of these articles are not specific either as to what forms of bulk power sales they see as subject to competition or as to the role that federal regulation of such sales would play in the competitive process. They frequently do not distinguish among various long-term bulk power supply alternatives (wholesale service, unit power sales, unit ownership entitlements) or between these long-term arrangements and short-term alternatives (such as economy interchange, short-term economy sales and emergency support). The general impression in the literature seems to be that competition would develop across the board if certain restrictive practices were eliminated and that this would be desirable.

In addition to considering wholesale competition, the literature focuses on several types of retail competition. Industrial location competition is a frequently mentioned form of retail competition among utilities.¹¹³ This form of competition may occur as industrial firms select the site for the location or expansion of their operations. It is argued that, other things being equal, firms will tend to locate in areas where they would receive service from the utility offering electricity at lowest cost. While most authors view this form of competition as important, some express doubts as to its prevalence.¹¹⁴

A second type of retail competition that has received considerable attention is competition for the retail franchise itself. A number of authors have stressed the potential for individual communities to determine, based upon competitive considerations, whether to form (or maintain) their own municipal or cooperative electric power distribution systems or to continue (or institute) service from an investor-owned utility.¹¹⁵

Still another form of retail competition referenced in the literature is "fringe area competition." This is generally defined as competition among utilities for customers located on or near the border of the retail service areas of two or more utilities so that more than one company may legally provide electric service. Several authors indicate that such competition takes place or is worth promoting at least under some circumstances.¹¹⁶ Others express doubts that this form of competition is either significant or desirable.¹¹⁷

¹¹¹Fairman and Scott, *supra* note 107, at 1204; Kahn, *supra* note 91, at 317; Meeks, *supra* note 107, at 104; and Weiss, *supra* note 107, at 170.

¹¹²Fairman and Scott, *supra* note 107, at 1204; Hjelmfelt, *supra* note 107, at 29; Kahn, *supra* note 91, at 317; Meeks, *supra* note 107, at 120; Penn, et al., *supra* note 107, at 44; Schwartz, *supra* note 107, at 564; and Weiss, *supra* note 107, at 170.

¹¹³Fairman and Scott, *supra* note 107, at 1162; Hjelmfelt, *supra* note 107, at 23, 27; Meeks, *supra* note 107, at 77; and Weiss, *supra* note 107, at 143.

¹¹⁴Kahn, *supra* note 91, at 318; J. D. Pace, "Relevant Markets and Nature of Competition in the Electric Utility Industry," *The Antitrust Bulletin*, Vol. XVI, No. 4, Winter 1971, A Special Issue; and Penn, et al., *supra* note 107, at 16-17. We discuss location competition at Sec. V-F.

¹¹⁵Hjelmfelt, *supra* note 107, at 26; and Schwartz, *supra* note 107, at 559-560. Our discussion of franchise competition may be found at Sec. V-G.

¹¹⁶Fanara, et al., *supra* note 107, at 133-134; Hjelmfelt, *supra* note 107, at 25; and Kahn, *supra* note 91, at 318.

¹¹⁷Meeks, *supra* note 107, at 95; and Penn, et al., *supra* note 107, at 16-17. It is interesting to note that one 100 megawatt industrial customer, Lukens Steel Company, is presently seeking approval of the Pennsylvania Public Utility Commission to construct facilities to allow it to shift service from Philadelphia Electric Company to Pennsylvania Power and Light Company 10 miles away. See *Energy User News*, December 14, 1981, at 1, 3, 19. See Sec. V-E for our discussion of fringe area competition.

Direct duplicative retail competition, in which two servers maintain the capacity to provide service to the same group of customers, is generally viewed as wasteful and most authors reject it as a goal for public policy. There are, however, at least two who express the belief that it is desirable and one of these has reported a statistical investigation which indicates that such competition may reduce costs over at least some range of firm sizes.¹¹⁸

Yardstick competition, or competition by comparison, also is mentioned frequently as a significant, or potentially significant, form of competition. While this type of competition is sometimes described as a part of franchise competition (i.e., comparisons by voters of the rates and performances of two potential holders of the retail franchise), we will use the term to refer to the more limited context of performance comparisons among utilities made by regulatory authorities. Such comparisons, it is alleged, may be useful in determining the prudence of managerial decisions and the relative efficiencies of utility operations. Many authors indicate that this type of competition is a valuable adjunct to regulation.¹¹⁹

The authors of the studies we have cited in this section are nearly unanimous in seeing favorable prospects for competition among electric utilities. We have indicated previously that the FERC assumes that franchise, fringe area and industrial location competition exist if the utilities are adjacent,¹²⁰ and that, in at least one instance, a court of appeals has accepted that judgment.¹²¹ Neither the authors, the regulators, nor the courts, however, carefully describe exactly how that competition will work or the mechanism through which it will result in improved efficiency. It is to that topic that we now turn.

V. THE POTENTIAL FOR EFFECTIVE COMPETITION, GIVEN THE PRESENT REGULATORY FRAMEWORK AND STRUCTURAL CHARACTERISTICS OF THE ELECTRIC UTILITY INDUSTRY

A. Wholesale Power Competition

In this subsection, we focus on the feasibility and desirability of stimulating wholesale power competition in the electric utility industry. We use the term "wholesale power" to refer to firm sales of system power from one utility to another. Such sales are clearly distinguished from unit power (either short-term or long-term), emergency power, economy power, diversity power or other short-term sales which generally are nonfirm and are priced on the basis of the individual generating units involved and their incremental generating costs at the time the transaction takes place.

¹¹⁸Richard Hellman, *supra* note 35; and Walter J. Primeaux, "An Assessment of X-Efficiency Gained Through Competition," *Review of Economics and Statistics*, February 1977, at 105-108. See note 150 for a discussion of Primeaux's study.

¹¹⁹Fairman and Scott, *supra* note 107, at 1162; Fanara, et al., *supra* note 107, at 140; Kahn sees this form of competition as valuable even though it is unfair where it compares public and private firms, Kahn, *supra* note 91, at 319; Meeks, *supra* note 107, at 77-78; Penn, et al., *supra* note 107, at 23; and Weiss, *supra* note 107, at 146. Our discussion of yardstick competition takes place at Sec. V-H.

¹²⁰*Connecticut Light and Power Company*, FERC Docket No. ER78-517, "Order Reversing Administrative Law Judge's Dismissal of Price Squeeze Allegations For Failure to Prove a Prima Facie Case," (August 1979).

¹²¹*Cities of Bethany, et al. v. FERC*, Docket No. 80-1633 (D.C. Cir. 1981).

Given the current and prospective regulatory framework within which electric utilities operate, there exists a strong economic *disincentive* to compete for wholesale business. This is true for at least three reasons: (1) The rates that utilities are permitted to charge for wholesale power are limited to covering average embedded costs, although the cost of new facilities is above that level; (2) Because the regulatory mechanism does not respond adequately to continuing inflation, there has been and continues to be no reasonable expectation of actually earning returns on investment which cover the costs of capital; and (3) The long lead times required to construct generation facilities and their long-lived nature make seeking wholesale business a risky proposition unless lead times and notice provisions longer than those which might be approved by regulators can be obtained. Each of these points is discussed below.

Wholesale power rates are set by the FERC on the basis of systemwide average costs. In greatly oversimplified terms, if a given supplier has, say, three equal-sized generating plants, one built in 1955 at a cost of \$150 per kilowatt, one built in 1965 at a cost of \$100 per kilowatt, and one built in 1975 at a cost of \$200 per kilowatt, then (ignoring depreciation) its average investment is \$150 per kilowatt and theoretically the demand charge portion of the wholesale rate would be set to cover the annual carrying charges associated with this average investment (including the average embedded interest on outstanding debt securities).¹²² Similarly, the energy charge portion of the wholesale rate would be set so as to cover the average operating costs of the three units. If it then becomes necessary to add a unit of the same size at a cost of \$350 per kilowatt to serve a new wholesale customer, the demand charge portion of the wholesale rate applicable to all wholesale customers would be set, assuming prompt regulatory response, to cover the annual carrying charges on the new average investment of \$200 per kilowatt. Likewise, the energy charge portion of the wholesale rate would be adjusted to reflect the new average operating costs.

Throughout a large part of the industry's history, both the capital and operating costs of new plants were below the costs of old plants and thus below systemwide average costs. Given this, load growth was encouraged to permit the construction of a greater number of new plants at lower costs which would thereby bring down average cost and rate levels. As a result of regulatory lag, the expanding supplier could expect to enjoy the benefits of lower average costs for a period of time before rates were reduced. In the last decade, however, the relationship between new plant costs and the average cost of existing facilities has reversed dramatically. Due to, among other things, the general rate of inflation, increasingly stringent environmental and regulatory controls and limitations on site availability, the capital cost of new plants now substantially exceeds systemwide average costs.¹²³ Also, as a result of declining thermal efficiencies associated with required environmental controls, as well

¹²²Wholesale customers, as well as large retail customers, typically are served under tariffs containing separate demand and energy charges. The demand charge assesses the customer for its peak consumption during the billing period on the theory that the supplier must provide facilities adequate to meet that peak requirement. The energy charge assesses the customer according to the number of kilowatt-hours consumed and, in theory, is intended to recover the variable costs associated with energy production.

¹²³See our discussion of this reversal later in this section.

as increasing fuel costs (which are fully reflected in new plant operations but, due to long-term contracts, may not affect old plant operating costs to the same degree), the operating costs of new plants may well exceed the system-wide average. Under these circumstances, more rapid load growth creates the need to build new, more costly, plants and thus drives up average costs and rates. Because of regulatory lag, it can be expected that some period will elapse between the time that average costs rise and the time that rates are permitted to increase in response to those higher costs.

The implications of average-cost pricing during a period when new plant or incremental costs exceed average cost are clear. In a "competitive" wholesale market, the winner is the loser. The shifting of wholesale loads to a supplier with a low average cost, and thus with low rates, can be expected to create a need for new construction by that supplier, drive up its costs, impose losses during any period of regulatory lag and drive up rates based on average cost after regulators respond to the new cost levels. Under such circumstances, *no rational supplier will compete for wholesale business*.¹²⁴ Customers cannot be given wholesale power alternatives unless suppliers are *forced* to provide power against their will at rates below the additional cost of making the sales. Any competitive scenario which assumes that customers may shop over a wide market area for wholesale power suppliers also *must* assume that suppliers will be forced to build additional capacity to comply with requests for wholesale power.¹²⁵

While even wholesale rates perfectly based on average costs would fail to cover incremental costs and would discourage utilities from voluntarily extending service, there is an additional disincentive if regulators do not approve rates that cover fully the utility's average costs. In fact, during the last eight-year period of continuing high rates of inflation, utilities have been consistently unable to cover their average costs (including even the rates of return allowed by the regulatory authorities). Utilities would be economically irrational to seek competitive opportunities to make sales that lead to a need for new capacity when the required capital investment will yield a rate of return below its cost. To do so would penalize the stockholders through lower earnings per share and, when capital must be raised through the sale of stock at prices below its book value (an almost universal circumstance for utilities), by dilution of stockholder equity as well.

The lead time required to plan and construct major additions to generating capacity is in the range of 8 to 14 years and once constructed, the

¹²⁴This is certainly correct as a generalization as long as present cost and regulatory conditions continue to prevail. However, we do recognize that some suppliers who currently have excess generation capacity, due to general declines in electricity demand, may find it in their interest to take on additional wholesale loads if the gain from the difference between the short-run marginal cost of service and the average embedded cost based rates is sufficient to offset the long-run losses associated with eventually having to add capacity at today's high capital costs. In the present financial and regulatory environment, which seems likely to persist for a considerable period, it is nearly certain that utilities will not persist in building capacity in excess of their needs. We view future capacity shortages as much more likely than surpluses. It must also be recognized that much "excess" capacity is oil-fired and may have operating costs which exceed the revenues that would be derived from average cost based rates.

¹²⁵After once agreeing to take on a wholesale customer, the supplier may have imposed on him an obligation to serve which commits him to continuing expansion. The wholesale customer, facing rates based on average power supply costs that rise at a much slower rate than true marginal costs, may aggressively seek expanded sales that, in turn, will exacerbate the wholesale supplier's problem.

capacity has a life of 30 to 40 years.¹²⁶ Responding to unanticipated wholesale load increases in a significantly shorter period of time (say, five years) is likely to involve the addition of small-scale, high-operating-cost generating units of a suboptimal type or the purchase of high-cost, short-term capacity and energy. As wholesale rates are now regulated, any attracted wholesale customer would not pay the marginal cost associated with a relatively quick sub-optimal expansion of capacity to serve it.¹²⁷ The acceptance of new wholesale loads on short notice would, thus, drive up the supplying utility's average cost at a supernormal rate. Except for temporary periods of capacity surplus, or very small loads for which generating capacity exists on a given system due to unforeseen declines in load or load growth (such as occurred on a widespread basis after the Arab oil embargo), alternative wholesale suppliers would be extremely reluctant to take on additional wholesale customers unless they were contemplating wholesale contracts beginning, say, 8 to 10 years in the future.

On the other side of the coin, given the long lives characterizing generating facilities and the time required to make optimal downward adjustments to capacity, unanticipated losses of wholesale load can be expected to leave the former supplier with excess capacity for a number of years. This in turn would drive up average costs and rates to remaining customers and, during any period of regulatory lag in adjusting rates, impose losses on the supplier.¹²⁸ It follows that suppliers not only will be reluctant (aside from the average-cost pricing and inadequate return problems) to compete for wholesale loads without adequate time to make reasonable capacity expansions, they also will need assurance that the new business will stay with the "winner" of the competition long enough to utilize the added capacity. Thus, a rational supplier might refuse to bid for wholesale contracts unless those contracts call for power deliveries to begin not less than 10 years into the future and contain a rolling 8- to 10-year notice provision required for termination of the arrangement by the buyer.

Of greater significance to our analysis, even if for some uneconomic reason electric utilities did choose to compete for wholesale customers or, more likely, if regulators compelled them to extend wholesale service to all who demand it, there is no reason to believe that shopping by wholesale customers would induce either the more optimal operation of generating facilities

¹²⁶Department of Treasury, Internal Revenue Service, *Depreciation*, Publication 534 (Rev. Nov. 1980), at 26-38; National Electric Reliability Council, *9th Annual Review of Overall Reliability and Adequacy of the North American Bulk Power Systems*, August 1979, at 7; U.S. General Accounting Office, Report to the Congress of the United States, *Electric Power Plant Cancellations and Delays*, December 1980, at 7.

¹²⁷Alternatively, capacity might be purchased. Ordinarily, the supplier who lost the wholesale customer would, as a result, have excess capacity available. The new supplier could then purchase capacity from the old server. Such capacity would normally be sold from the old supplier's least-efficient, highest cost units. The net result of such a transaction would be that the wholesale customer would be served by the same generating resources that served him previously. The only change would be that the wholesale customer would have gotten to share in the low, embedded costs of the new supplier and would have forced the new supplier and its other customers to bear increased costs.

¹²⁸As note 127 points out, it is possible that the supplier losing the load will be able to sell capacity to the new supplier, and possibly at a price above the wholesale rate. However, the wholesale supplier certainly has no assurance that any excess capacity dumped on him by an unanticipated wholesale customer shift would be marketable. This would depend, among other things, on the balance between load and total resources in the region at the time the shift took place. It should also be noted that the supplier losing load may not be able to pass on the responsibility of carrying redundant capacity to its remaining customers. Its regulators may choose instead to remove the excess capacity from its rate base thereby imposing all the costs of the customer loss on stockholders.

in the short run or the expansion of lower cost facilities by more efficient constructors of capacity in the long run. Rather, what generally could be expected is only a redistribution of the benefits of embedded costs among various customers.¹²⁹ Wholesale rates based on average embedded costs convey price signals which will tend to result in customers making the wrong economic decision as frequently as the correct one. As long as average-cost pricing prevails for wholesale power, regardless of whether incremental cost is above or below average costs, the selection of suppliers based upon such rates will bear no necessary relationship to the supplier's efficiency in furnishing additional power. Thus, the fundamental objective of competition—that is, to shift business from inefficient suppliers to more efficient suppliers—cannot be fulfilled by a system of supplier selection based on average cost.¹³⁰

An electric utility supplier's average embedded costs may be relatively low for a variety of reasons unrelated to its current or prospective efficiency. It may have acquired favorable river sites which enabled it to obtain a relatively large proportion of its existing capacity requirements from extremely low-cost hydroelectric plants. It may have grown relatively slowly in the last 10 years, thus minimizing its need to construct high-cost plants during a time of rapid inflation. It may have entered into a favorable long-term fuel purchase contract. Or, in the past, it may have had a highly efficient construction manager. In none of these cases is the advantage expanded if new wholesale customers are attracted by the existing low rates. Rather, such advantages merely are stretched thinner as new customers obtain a share of the benefits through rates based on average costs that previously accrued to existing wholesale and retail customers.

The changed character of the industry during the past decade renders the prospect of supplier selection using rates based on average cost even more unattractive than in the past. For a number of reasons, average costs have become an even poorer approximation of marginal costs. First, until the early 1970s, the industry grew at an average compound rate of 7 percent per annum. This meant that load doubled every 10 years and meant that roughly half of any system's total capacity (upon which systemwide average costs and rates were based) had been constructed within the past 10 years. The average cost achieved and rates offered by any utility, therefore, in significant part reflected its *recent* efficiency in constructing capacity and perhaps could be expected to bear some relationship to expected efficiency in bringing on new capacity.

Second, the lead times required to plan, construct and bring generating capacity on-line were considerably shorter than those prevailing today. This made it much more likely that the same planners, engineers and managers who had achieved good performance and relatively low costs over the last few

¹²⁹In the short run, there often would be no change in efficiency. Where comprehensive pooling arrangements exist, total generation in the area is already loaded so as to meet total area load at the least cost.

¹³⁰In some circumstances, real resource efficiency clearly may be adversely affected. If systems with generation are given access to wholesale power rates, they may make uneconomic decisions to shut down their existing generating capacity and take wholesale service instead. Also, the purchasing utility may abandon its own plans to construct new capacity in favor of wholesale power based on average cost even if the purchaser could have constructed new capacity more efficiently than the seller.

years would be available to plan and bring on new capacity. Again, there was a greater chance that past efficiency, as reflected in low average costs, would be linked to future efficiency in meeting expanding loads.

Third, and somewhat related to the first two points, because incremental costs were less than average costs, higher rates of growth were desirable both from the utility's and the regulator's points of view. Given this, aggressive utilities could attempt (with the regulator's blessing) to maximize their own growth and thus achieve average costs even more closely approximating current costs. (A 12 percent rate of growth, for instance, would lead to a doubling of capacity every six years.)

Finally, to the extent that deviations from average-cost pricing occurred, regulators permitted only deviations downward in the direction of incremental cost. Wholesale suppliers at least had the option (and perhaps could be pressured by actual or potential customers) to price nearer to incremental cost so that supplier selection could be made on a more economically appropriate basis.

In sharp contrast, in today's environment, longer lead times, slow electric load growth and the changed nature of the regulatory and environmental problems facing utilities suggest that the relationship between a utility's existing average cost and rates and its probable efficiency in adding capacity to meet load growth may be little more than random.

In sum, we conclude that under the economic conditions which have characterized the electric utility industry for the last decade and which seem likely to prevail for the foreseeable future, a competitive market for the supply of wholesale power cannot develop unless potential competitors are forced against their will to make wholesale service available to all who demand it. Moreover, even if such a market were artificially created (by compelling reluctant suppliers to furnish service to all potential customers), it could not be expected to result in an increase in efficiency because of the faulty pricing mechanism characterizing this market and the long lead times required to alter capacity to reflect gains or losses of significant loads. There simply is no economic rationale for permitting wholesale customers to select among suppliers by comparing prevailing wholesale rates based on average cost. No sensible public policy, whether directed at antitrust, energy conservation or general public interest standards, should be aimed at creating wider opportunities for power supplier selection based on systemwide average costs.

This pessimistic judgment regarding both the feasibility and desirability of stimulating wholesale competition, of course, takes the present regulatory framework and industry structure as given. In particular, the average-cost pricing of wholesale power alone is sufficient to destroy rational arguments for introducing competition for such power.

To date, public policy has not been directed toward any significant expansion of wholesale competition. We have been able to find no instance in which the FERC has ordered a company to make its wholesale tariff generally available to customers beyond its areas of service. Likewise, the NRC, even while frequently requiring the availability of bulk power as a license condition, has not required that wholesale power be supplied to utilities outside the

service territory of the licensee.¹³¹ Congress, in enacting PURPA, added specific language to the wheeling provision prohibiting the FERC from mandating wheeling transactions which would result in the loss of wholesale load to the wheeling entity.¹³² On the other hand, aside from some NEPOOL proceedings, until recently, we are unaware of any customers requesting such service. However, this is a topic that public policy is likely to have to address in the near future. On the basis of our analysis, we urge that policy continue to reflect restraint in considering expansion of wholesale power competition. While, as we discuss later, it may be feasible to increase some bulk power supply option to wholesale customers, the right to choose among wholesale power suppliers on the basis of embedded cost rates should not be among them.

B. Unit Bulk Power Supply Competition

Without the necessity for fundamental alterations in the way the electric utility industry is regulated or structured, it seems clearly feasible to make available unit power alternatives to buyers and, in at least some circumstances, to have willing participation in such transactions by sellers. However, under the circumstances characterizing the industry today, we conclude that there is little likelihood that such buyer choice would stimulate efficiency in the provision of bulk power supply. The reasons underlying this conclusion are discussed below. It is necessary, however, to begin with a comprehensive description of the types of transactions under consideration.

Unit power supply competition involves the purchase of power from specific generating units for extended periods (unit power purchases) or the purchase of ownership interests in specific units (ownership entitlements). A purchase of unit power entitles the buyer to a specified portion of the capacity and output of a given generating unit. Thus, a buyer purchasing, say, 5 megawatts from a planned 500 megawatt unit would be entitled for the length of the contract to 5 megawatts of capacity and, at any given time, to 1 percent of the plant's kilowatt-hour output (5 megawatts divided by 500 megawatts). The buyer would have to arrange for an alternative source of power when the plant was not operating because of scheduled or unscheduled outages. Under present regulation, the price paid for unit power is directly related to the actual incurred generating unit costs. In our example, the buyer would agree to pay 1 percent of the annual carrying charges (cost of money, depreciation, taxes and insurance) associated with the investment in the plant, and the operating expenses (fuel and labor) incurred in producing any output he schedules from the plant.

An ownership entitlement is functionally identical to a unit power purchase. In this case, the buyer would purchase an ownership interest in the planned unit by contributing a proportionate share of the capital required to construct the unit and by sharing proportionately in the monthly operating and maintenance expenses of the plant. The "price" seen by the prospective purchaser of an ownership entitlement may differ very substantially from the

¹³¹With the exception noted in our discussion at Sec. III-A.

¹³²16 U.S.C. § 824(k).

unit power price, however. If a municipal electric utility is the buyer, generally it will not be required to pay local property, gross receipts or any other taxes on its share of the generating plant or its output. Moreover, the municipality will be able to raise capital by issuing tax-free municipal bonds and thus, will achieve a nominal capital cost several percentage points lower than that faced by the primary owner and constructor of the generating unit. From the municipal buyer's perspective, therefore, the "price" of an ownership entitlement almost always will be substantially lower than the price of a unit power purchase.

An ownership entitlement purchased by a cooperative electric utility also embodies the substantial tax and capital-raising advantages discussed in Section II above. These include lower or nonexistent property taxes, freedom from all income taxes and the ability to borrow money directly from the REA or obtain funds guaranteed by that agency at rates below the market cost of capital. Thus, as is true for municipal utilities, it is difficult to envision a situation in which the cooperative utility buyer will not find the "price" of an ownership entitlement substantially lower than the price of a functionally identical unit power purchase.

It also is important to stress that the long-term transactions under discussion are for purchases of unit power or ownership entitlements in *planned* generating units. As explained in the succeeding paragraphs, we do not envision construction by rival bulk power suppliers of excess generating capacity which then would be brokered in a "competitive" market. Rather, at the time a capacity addition was being planned, the size of the expansion (or perhaps the viability of constructing any plant at the planned time) would be at least partially dependent on the contractual commitments of buyers to make unit power purchases or to take ownership entitlements. In short, suppliers would not build capacity first in the hope of selling it later; construction of capacity would not begin until the supplier had in hand firm contractual commitments for all or virtually all of the planned capacity.

We assume away the building of excess capacity in the hope of later selling it in a "competitive" market for a number of reasons. In brief: (1) sellers would have no incentive to participate in such a market; (2) the financial community would be unlikely to support it; and (3) regulators would not permit it. Let us address each of these points. A supplier considering the construction of a larger unit than it needs with a view to offering the excess for sale at a later time would face the following situation. First, if it judged correctly and it could sell all of the excess capacity constructed, under the current regulatory scheme, it would be able to charge no more than the cost associated with that capacity, including the regulator's judgment of what constitutes a reasonable rate of return (a rate that based on recent history seems likely to be below the market's evaluation of the cost of capital). On the other hand, if the supplier were unsuccessful in selling off all excess capacity, it would run the very significant risk that regulators would not allow recovery of its excess investment costs. At a cost on the order of \$1,000,000 per megawatt of base load capacity, the losses could be staggering. A supplier considering the construction of the additional capacity to take on even one or two additional average-sized municipal or cooperative customers would need to build perhaps 50 megawatts of excess capacity and thereby put a \$50 million investment at risk.

Beyond this, in every region of the country today, both through individual pooling organizations and through regional reliability councils, projections of electric load and planned capacity additions for at least 15 years into the future are prepared by and circulated among all suppliers in the region. Regional reliability councils compile, evaluate and publish the plans of member systems in an effort to make sure that adequate, but no more than adequate, capacity is provided to meet projected needs. Given this, an individual supplier desiring to create significant capacity to sell competitively could hide this fact from other suppliers only by overstating its own electric load projections, thus making its load and capacity expansion plans appear to match.¹³³ The end result would be the creation of truly redundant capacity, since on a regional basis, capacity expansion plans would have been matched to deliberately overstate demand projections. Attempting to induce customers to shift bulk power suppliers by marketing redundant capacity would be likely to drive prices below the new unit's costs, since in the short run, other suppliers would be better off to cut prices below their full cost and, potentially, to the level of short-run marginal cost. Accepting any rate above out-of-pocket costs would be preferable to losing customers and consequently being unable to cover any fixed cost. In short, the prospects for recovering costs by creating and then selling excess capacity would be slim. Thus, no rational supplier would expand capacity with the full knowledge that it would be in excess of the industry's foreseeable needs.

Even if for some uneconomic reason electric suppliers desired to expand generating capacity in the hopes of later marketing it competitively, it is doubtful that the financial community would support such ventures. Electric generating capacity is extremely capital intensive, long-lived (typically 30 to 40 years), completely inflexible (it can perform no function other than producing electricity to serve demands within a defined geographic area), and, under the best of conditions, yields only a modest return to investors even if fully utilized throughout its physical life. There is no evidence to suggest that an investment of this nature could be financed on a speculative basis.

Finally, even if suppliers had the desire and financial capability to create capacity for a "competitive" market, under existing regulatory conditions this would be prohibited. As a result of its financial and environmental impacts, virtually any substantial electric generating plant planned today must be supported by a rigorous showing in an adversary proceeding that there is "a need for the power". Such a proceeding examines not only the electric load projections of the proposed constructor to see that they are not unduly optimistic, but also considers the availability of other capacity in the region that might be purchased in lieu of constructing the capacity under consideration. In short, the primary aim of such regulation is to eliminate redundant capacity in the industry.

For all of these reasons, it seems feasible for buyers to obtain alternative long-term bulk power supply sources only by making commitments to take capacity and energy from future units during the planning stage—at the very least, before environmental clearances have been obtained and before equip-

¹³³As discussed below, load forecasts today are subject to regulatory review in adversary proceedings.

ment supply arrangements lock in the unit size. Ordinarily, this means that, in order to exercise choice, buyers would be required to make firm contractual commitments to take capacity from the specified generating units 8 to 14 years before the capacity would become available.¹³⁴

The duration of the required commitment also must be considered. An ownership entitlement, of course, commits the buyer to the chosen generating unit throughout its life. Unit power commitments also may extend for the life of the unit, but could be for shorter periods. The contract length needed to protect the seller would depend upon lead times, the growth rate of the supplier's other customers and the relative significance of unit power sales. As an example, if unit power purchases were significant enough relative to the supplier's internal load growth that, say, load growth of 20 years would be required to absorb the capacity that could be released by unit power customers, then 20-year contracts would be needed to assure the supplier of full utilization. More likely, given a reasonable expectation by buyers that continued inflation and tightening environmental controls would drive the costs of future generating units ever higher, buyers probably would want to lock-in unit power for the life of the units. Sellers, given the need to satisfy financial and regulatory constraints, likely would prefer life-of-unit contracts as well.¹³⁵

With the benefit of this background, we now turn to a consideration of the feasibility and desirability of introducing competition in unit participation. In particular, we address the incentives that sellers would have to participate voluntarily in such transactions and the prospects that promoting wider sellers' choice in this arena would enhance economic efficiency.

The seller of an ownership entitlement may gain from the transaction in either of two ways. First, it is possible that by selling entitlements, a significantly larger generating unit can be constructed than otherwise would be built, thus permitting both the main supplier and the buyers of entitlements to enjoy economies of scale otherwise unavailable. However, since a major portion of the nation's generating capacity is owned by utilities large enough to build optimum-size fossil-fuel units without joint action, this benefit often will be irrelevant to potential suppliers.¹³⁶ Second, when the rate of return allowed by regulators is below the cost of capital, utilities will avoid capital outlays whenever possible in order to avoid reducing the returns earned by existing stockholders and diluting their equity. This means that in today's economic climate, whenever it is possible to *substitute* a transaction in which

¹³⁴Since the Arab oil embargo resulted in skyrocketing fuel costs and an unanticipated decline in the rate of growth of demand for electricity, a number of utilities have been plagued by excess capacity. Moreover, during this same period, because allowed rates of return have been below the cost of capital, it has been difficult for investor-owned utilities to continue financing even those plants already under construction. Under these (presumably temporary) conditions, a number of utilities have been able to purchase entitlements in existing or partially constructed units on either a short- or long-term basis.

¹³⁵As discussed in note 134 above, given the industry's present excess capacity and capital shortage, short-term arrangements are being made. However, we view this as a temporary situation and not as a valid basis for discerning the types of transactions that could be expected in a normal competitive market.

¹³⁶For example, the 20 largest investor-owned operating systems in 1979 accounted for 49 percent of total investor-owned capacity. The smallest of these, Union Electric Company, had an annual peak demand of 5,557 megawatts. Even if its load growth were only 3 percent a year, it will need to meet a load increase of 2,366 megawatts by 1991. With that level of growth over the period over which a base load unit would be planned and constructed, there is clearly no need to solicit participation of other utilities. Derived from information contained in "The Top 100 Electric Utilities' 1979 Operating Performance," *Electric Light and Power*, Vol. 58, No. 8, August 1980, at 13; *Statistical Year Book*, supra note 5, 1976, at 6.

the buyer provides capital (that is, an ownership entitlement) for an obligation to furnish capacity using the supplier's own capital, the supplier will have an economic incentive to do this.

It is important to stress that the benefit to the supplier is in reducing its capital investment responsibility. The supplier will gain nothing merely by selling unit power to customers it did not previously have. Let us see what this means. Suppose the allowed rate of return is below the cost of capital but that, in order to meet its public service obligation to its retail and wholesale customers, the supplier is planning to construct a 500 megawatt unit at a cost of \$500 million. If the existing wholesale customers offer instead to make a \$50 million capital contribution and take a 10 percent ownership entitlement in the planned unit, the supplier will minimize harm to its stockholders by making the deal. On the other hand, the supplier will have no apparent incentive to seek additional participants so that, say, a 700 megawatt unit can be built with others contributing \$250 million. (The supplier's investment is \$450 million in either case.) In short, the capital-squeezed supplier will only have an economic incentive to convert *existing* obligations into ownership entitlements; it will have no economic incentive to compete to attract additional buyers.

At first glance, it might appear that the builder of a generating unit at worst would be indifferent to expanding planned units in order to accommodate the ownership entitlement demands of additional buyers. However, this is unlikely to be true. Rather, it is more likely that the supplier will have a clear *disincentive* to accommodate any such preferences. Transactions costs arising from dealing with a number of relatively small co-owners clearly will be higher.¹³⁷ Beyond that, taking on additional loads will contribute to the exhaustion of favorable generating sites, sources of fuel supply, environmental resources (clean air and water), and transmission corridors in the supplier's area.¹³⁸

Consider now the supplier's incentives to make unit power sales. First, as is true of ownership participation, it is possible that selling unit power will enable the supplier to construct units of a more economical size. The limited applicability of this incentive previously has been noted. Second, if the allowed rate of return exceeded the cost of capital, the supplier would have the normal profit-motivated incentive to make such sales, assuming that the costs of exhausted sites, favorable fuel sources, environmental resources and transmission corridors were not viewed as overwhelming. If the allowed rate of return is below the cost of capital, however, suppliers will have a major disincentive to seek out unit power buyers. Every buyer attracted will increase the utility's capital need and thus further depress stockholders' earnings and dilute their equity.¹³⁹

¹³⁷Additional risks to the primary owner may also be created by multiple ownership, particularly of nuclear units. Small owners may not have the financial strength to meet their share of the large outlays that could be required in the event of an accident.

¹³⁸In addition, the seller may have to assume obligation for emergency support, wheeling and other short-term services.

¹³⁹There would also be an incentive for the supplier to sell unit power when it would derive more revenue than it would under its wholesale tariff (i.e., it would convert an average cost customer into a marginal cost customer). However, it is unlikely that the buyer would be willing to accept an arrangement under which he would pay more. As long as the unit power sale is made to a full requirements customer, it is essentially a zero sum game. One utility's gains are the other's losses. Under these circumstances, such transactions are unlikely.

In sum, we conclude that suppliers ordinarily will have no incentive to *seek out* takers of ownership entitlements or unit power under current and prospective economic conditions. As long as the allowed rate of return is below the cost of capital, suppliers will have an incentive to *convert* other actual or perceived obligations to serve into capital-yielding entitlements, but no incentive will exist to seek out new loads.

Assuming that suppliers would be willing to vie to make available ownership entitlements or unit power, or could be forced to make such options available, could buyers be expected to make economically efficient decisions? Given the institutional arrangements presently characterizing the electric utility industry, we have serious doubts. Efficient decisionmaking will be thwarted by incorrect price signals and by the difficulty of obtaining reliable price and performance information regarding planned units. Consider first the price distortion point. If buyers have a choice of obtaining their bulk power supply by purchasing wholesale power based on average cost, ownership entitlements or unit power, they will lean either toward purchasing wholesale power (that during an inflationary period is generally priced below the cost of power from new units) or toward ownership entitlements that permit them to take advantage of subsidies. As explained in the subsection above, there is no linkage between economic efficiency and power purchase decisions based on average embedded cost rates. The availability of a wholesale rate not reflecting current costs will distort any choices made in a bulk power market. The second distorting influence is the subsidy received by municipally owned and cooperative utilities. Whenever there exists a choice, such buyers will prefer ownership entitlements. If entitlements are offered in some units but not others, biased decisions clearly will be made. Beyond this, even if ownership entitlements were available in all planned units, since the subsidy received by municipals and cooperatives is entirely capital related, such systems will prefer technologies that are overly capital intensive from an economic efficiency viewpoint.

If such price distortion did not exist, individual systems could, *in theory*, spur efficiency by buying from the units offering the best combination of cost, operating characteristics and planned in-service date. Such purchases would enhance the real economic efficiency of the industry by directing demand to the lowest cost, best performing suppliers that would then construct larger units or a greater number of units. Thus, theoretically, an increasing portion of the responsibility for the industry's capacity would be shifted to efficient suppliers. In practice, however, there are significant impediments to such a smoothly performing market.

In order to have any hope of making efficient decisions regarding participation in planned generating units, buyers or their agents will have to make in-depth analyses of available generating unit technologies, the availability and prices of fuels expected over the next 50 years, and the cost effects of current as well as prospective changes in site, environmental, safety and other regulations. The transactions costs associated with making such analyses clearly would be burdensome to the average-sized municipal or cooperative distributor. Even the best estimates of such cost parameters made at the time of announcement have often proven highly unreliable. Beyond this,

whether the unit will be built at all is open to question, since unit power or participation contracts generally give the constructing utility the right to cancel or delay the unit at its option. Given these facts, the prudent purchaser would desire to diversify both financial and electrical reliability risks by participating in a large number of units constructed by several different utilities. This would reduce the risk of participation but at the same time would greatly increase transactions costs and limit the effective range of choice available in the market. If each buyer purchased an equal share in each new plant constructed in its area, it would reduce its risks. However, it would, by definition, have a portfolio of ownership interests or entitlements which would insure it only average price, average reliability and average in-service experience for the total capacity added.

Since prospective purchasers of unit participation would have difficulty assessing the relative desirability of future units, one might argue that they could make decisions by comparing the past records of alternative builders of capacity. If one company had a better record than others for designing, constructing and operating generating plant, the future units of that utility could be selected over those of others for participation. To the extent that past efficiency turned out to be associated with future efficiency, and to the degree that buyers could meaningfully analyze past performance, an efficient market could develop.

As previously discussed, the long period required for the construction of new units, and the slower growth in electric demand which leads to fewer new units being constructed, means that the individuals who were instrumental in designing and building present capacity are unlikely to be those involved in newly announced units. Changes in technology and fuel types, the addition of emission control equipment, and changes in scale mean that few utilities build units identical to those for which they have specific construction and operating experience. Thus, looking to the past as a guide to future performance does not seem especially promising. It seems fair to say that despite considerable past efforts to develop statistical efficiency measures or performance audit procedures upon which managers and regulators can rely, it is generally agreed today that objective measures of relative utility efficiency do not exist. If neither the utilities themselves nor the regulators have been able to devise such measures, it seems clearly unrealistic to expect individual bulk power customers to do so.

In sum, under anything like the existing regulatory environment and structure of the electric utility industry, it is difficult to envision the operation of an efficient long-term bulk power supply market. The prospect of buyers shopping for power, some of which is artificially underpriced and all of which may or may not be available at anticipated future dates, based on relative costs which are burdensome to assess, and furnished by sellers who have no particular motivation to compete for business, is not at all appealing. There is no reason to expect such a "market" to develop or to function in ways so as to promote an efficient allocation of resources.

Trends in public policy, however, seem to be at odds with our assessment of the underlying economics. In proceedings before the NRC, a great deal of emphasis has been placed on providing *ownership* access for municipal and

cooperative utilities in nuclear and, in some cases, other base load generation.¹⁴⁰ The NRC has required specifically that ownership shares (in addition to unit power purchase options) must be made available to allow municipal and cooperative utilities to exploit their subsidies. Yet the NRC has nowhere analyzed the efficiency effects of its decisions. Instead, it seems to have been preoccupied with creating additional "competitors" (owners of generating units) rather than with stimulating the competitive process. As a result it has mandated the most distorting types of transactions. We are aware of no evidence that its decisions have done anything but substitute ownership entitlements for wholesale transactions. Since such substitutions have no effect on the actual construction or operation of the generating units, they distort relative price signals with no efficiency gain. It is also clear that the NRC did not engage in any "second best" balancing to determine a special need for ownership entitlements. In both the Consumers Power (Midland) and Alabama Power (Farley) proceedings, it was demonstrated that the intervenors already had lower retail rates, lower bulk power supply costs, and the prospects of a widening advantage over their competitive supplier.

Let us digress at this point to examine one possible method for promoting long-term bulk power supply competition. Promotion of competition in bulk power markets requires that appropriate price signals be available. One approach that would assist in achieving this would be to gradually phase out wholesale rates based on embedded costs and allow each utility to shop for its additional power and energy at prices reflecting its incremental costs. We believe that this is feasible and, while subject to some of the difficulties raised above, is likely to promote a more efficient allocation of resources.

Specifically, we propose that existing wholesale customers having viable power supply alternatives be limited in the amount of electricity they may purchase at embedded cost based rates. Their proportionate share of electricity produced from their suppliers' present facilities could be made available to them at average cost, while requiring that any additional requirements be obtained in the market. While a detailed description of exactly how this would work is beyond the scope of this paper, some elaboration is useful to show how such a policy would help remedy the deficiencies of the present arrangement.

Under this plan, the wholesale supplier would file a tariff limiting its wholesale obligation to the present requirements of its customers and the growth of those requirements over a reasonable planning period (i.e., 5 to 10 years depending on the circumstances). Thereafter the amount available would be proportionate to the output of the suppliers' generation capacity existing as of the end of the planning period. The cost of the wholesale power would be based on the average embedded costs of these units (i.e., the costs of generation units put into service after this date would be excluded). As units are retired, or their output is cut back as more efficient units are added to the suppliers' system, the amount of embedded cost power available to the cus-

¹⁴⁰While some unit ownership participations appear to result directly from license conditions, other such arrangements have come about due to the difficulties investor-owned utilities have had in financing their construction programs.

tomers would be reduced. A notice period for such reductions would be required.

The wholesale supplier would provide its customers with the opportunity to purchase unit power from generation it is constructing and would make available the usual array of support services to allow economic participation (i.e., emergency support). The supplier would likewise make wheeling available over its transmission lines to allow the customer to shop for its incremental power requirements from other utilities. The wheeling option would, of course, be dependent upon the supplier's having adequate transmission capacity to accommodate the transaction or being given adequate notice to provide the necessary capacity.

This policy suggestion has a number of advantages: (1) it would promote competition among alternatives to the extent such competition is practical; (2) it would eventually eliminate embedded cost wholesale regulation as existing facilities are retired; (3) it would require each supplier to face the marginal cost of expanding sales, and thereby give wholesale customers the incentive to adopt appropriate price and load management policies; (4) it would gradually eliminate price squeeze as a policy issue; and (5) it would put wholesale customers and suppliers on a plane of equality in controlling their power supply costs.

C. Short-Term Capacity and Energy Competition

In this subsection, we consider the prospects for introducing competition into the buying and selling of short-term capacity and energy. In particular, the focus is on transactions involving emergency power, economy power and short-term (one week to several years) capacity and energy. In the discussion below, it will be important to distinguish three alternative scenarios for participating in such transactions: (1) Gaining access to existing arrangements designed to facilitate short-term transactions. Such arrangements are the result of cooperative rather than competitive efforts by the utilities involved and are subject to FERC approval of prices as well as terms and conditions; (2) Substituting competition for cooperation and regulatory oversight as the means for establishing the terms and conditions under which buyers and sellers will execute short-term transactions; and (3) Substituting competition on a transaction-by-transaction basis for purchases and sales that now take place under terms and conditions dictated by long-term agreements. We focus first on economy power arrangements and then discuss in turn emergency and other short-term transactions.

The vast majority of electric generating capacity in the United States today is owned by utilities that participate in central dispatch or economy power arrangements. The objective of either arrangement is to satisfy the combined electric loads during each hour of operation of all the participating utilities at the lowest total operating cost. The economic significance of such arrangements has increased greatly in the past decade as disruptions in fuel markets have lead in some cases to marked differences in operating costs among utilities located in the same region. In greatly oversimplified terms, the process works as follows: Assume that three utilities enter into a central dis-

patch arrangement. Utility A has a 100 megawatt generating plant that produces kilowatt-hours at a marginal cost of 1 cent each. Utility B's 100 megawatt unit has a 1.5 cents per kilowatt-hour marginal cost. Utility C's equal-sized unit produces at a marginal cost of 2 cents per kilowatt-hour. Under a central dispatch arrangement, the operation of all three units would be under unified control. If at midnight, each of the three utilities has a 30 megawatt load, the central dispatcher would operate only the 1 cent per kilowatt-hour, 100 megawatt unit, thus satisfying the total 90 megawatt load at the lowest cost.¹⁴¹ If each utility's load rose to, say, 50 megawatts at 8:00 a.m., the central dispatcher would place the 1.5 cents per kilowatt-hour generating unit in service. At that point, 100 megawatts would be supplied by the 1 cent unit, and 50 megawatts would be supplied by the 1.5 cent unit. If by 2:00 p.m. each utility's load rose to 80 megawatts, the central dispatcher would operate units one and two at full capacity and would start up unit three (the 2 cent unit) to supply the last 40 megawatts. In all cases, the combined load would be met at the lowest total cost. As long as individual utilities are assumed to purchase fuel, labor and other operating inputs efficiently, the central dispatch arrangement maximizes economic efficiency in the short run—that is, no rearrangement of short-term transactions or changes in their prices will produce a more efficient result.

An economy power arrangement is designed to accomplish the same end, although less mechanistically. Under such an arrangement, while the three utilities would dispatch their units separately, they would agree to buy and sell economy power among themselves, perhaps in 15-minute intervals, on a split-the-savings basis.¹⁴² If economy sales and purchases are pursued diligently, short-term efficiency is maximized.

As the above discussion makes clear, as long as generating utilities have access to regional central dispatch or economy power arrangements, then *given* the input prices paid by those utilities and the demands they face, efficiency will be maximized. Injecting competition into such transactions will improve efficiency only if it spurs an improvement in the efficiency with which operating inputs (fuel and labor) are purchased by individual utilities or if it results in more efficient pricing of electricity to ultimate consumers and only if those benefits were not outweighed by increased transactions costs or disruptions to unit dispatch on an incremental cost basis.

As discussed above, economy sales now routinely take place both within and among groups of utilities on a split-the-savings basis. To introduce “com-

¹⁴¹ Again, recall that we are oversimplifying. In reality, on any electrical network, multiple units always would be operated in order to maintain reliability and regulate voltage.

¹⁴² This means that at midnight, when each utility has a 30 megawatt load, Utility A would operate its 1 cent per kilowatt-hour unit to satisfy its own needs, would sell 30 megawatts to Utility B at a price of 1.25 cents per kilowatt-hour and would sell 30 megawatts to Utility C at a price of 1.5 cents per kilowatt-hour. When each utility's load rose to 50 megawatts, Utility A would serve its own needs and sell 50 megawatts of power to Utility C at a 1.5 cents per kilowatt-hour price. Utility B would meet its own 50 megawatt need with its 1.5 cents per kilowatt-hour unit. Again, the most efficient combination of units would be serving the combined 150 megawatt load. Finally, when the combined loads rose to 240 megawatts, Utility A would meet its own requirement and sell 20 megawatts to Utility C at a 1.5 cents per kilowatt-hour price, Utility B would meet its own requirement and sell its 20 megawatt excess to Utility C at a 1.75 cents per kilowatt-hour price, and Utility C would operate its own unit to satisfy the remaining 40 megawatts of load.

It is worth noting that in reality, the lowest cost units are seldom involved in economy transactions. Ideally, a utility installs base load generating units with low operating costs on its system only up to the point where, given its load pattern, those units will be operated 70 percent or more of the time to meet its own load. By definition, this means that such low-cost units are available to furnish kilowatt-hours to other systems only a small portion of the time.

petition" into economy power transactions presumably means to permit individual systems to bid for limited supplies of economy power on other than a split-the-savings basis. If such direct rivalry were permitted, however, the traditional economy power arrangement would seem likely to collapse. Some members could hardly be expected to adhere to a shared-power, split-the-savings arrangement while others freely bid against such an arrangement.

The question then arises: How might the market work if the existing cooperative split-the-savings arrangements were replaced with competitively determined arrangements? In a competitive market, sellers would seek out the highest price available for any energy and buyers would search for the lowest price. The price at which any particular transaction would take place would be determined by the interaction of supply and demand. The price would not be lower than the seller's incremental cost or higher than the buyer's decremental cost. But, within this range, the price that would prevail would depend upon each system's bargaining power and upon its knowledge of other systems' costs. Each buyer and seller would have an incentive to keep its alternatives, and perhaps its own costs, secret so as to gain the best bargaining position. The transactions costs associated with bargaining on a continuous basis without the benefit of complete and accurate information could be significant. Moreover, the likelihood that less efficient transactions would take place would be great. Due to buyer and seller ignorance, a buyer with 2 cent alternative costs might well outbid a buyer with 2.2 cent costs. This would be in contrast to the smoothly working efficient mechanism for exchanging economy power now generally in place in the industry.

Some observers have pointed to the Florida Energy Broker System as a form of continuous competition in the exchange of economy power. This system provides that each participating utility quotes hourly a price at which it is willing to purchase and sell energy. These quotes are supposed to reflect the short-term marginal cost of additional production (for sales) or the short-term savings of reducing generation from the highest cost unit currently operating (for purchases). The broker matches the highest bidding price with the lowest asking price and continues to arrange such trades as long as there are net savings to be achieved. Savings from each trade are split evenly between buyer and seller.

As long as buyers and sellers actually do bid their incremental and decremental costs (rather than "gaming" the system by concealing the true extent of their savings) and wholesale customers are prohibited from offering for sale their average embedded cost purchases, this arrangement functions very much like an economy exchange. We do not view this arrangement as an example of competition, although it may achieve the efficiencies available from short-term trades.

Even without continuous bargaining, competitive determination of a formula which sets the price at which two or more utilities would exchange economy power would seem to be feasible. A utility having particularly low operating costs might bargain to obtain 70 percent of the savings accruing from each transaction.¹⁴³ In this situation, as would be true under continuous

¹⁴³Ironically, a very high-cost utility also would have an attractive bargaining position. Because its high costs would tend to result in large savings from economy transactions, it could bargain for a disproportionate share of the savings and the seller still would find the deal very profitable.

bargaining, individual utilities clearly would have an incentive to keep their alternatives secret, and perhaps as well, to obscure their cost information. More significantly, unless all economy power in a region were priced according to the same split-the-savings formula—something that seems inconsistent with a competitive scenario—inefficient transactions would take place.¹⁴⁴

In short, the injection of competition into economy power arrangements would almost undoubtedly increase transactions costs and lead to at least some lost opportunities to dispatch efficiently. Consider now the countervailing benefits that might flow from such competition.

It can be argued that the utility's incentive to purchase operating inputs efficiently is muted in those cases when the applicable fuel adjustment clause passes on directly to ratepayers not only fuel cost increases but any savings or "profit" made on economy power transactions as well. In those instances, a utility participating in a central dispatch arrangement holds down its retail and wholesale rates but does not directly increase profits. To heighten incentives to optimize short-run operating efficiency, all that would seem to be required is that regulators systematically permit at least a portion of the savings achieved from short-term transactions to be passed on to stockholders. Competition would change utility incentives only if its introduction served as the excuse for removing or relaxing the profit constraints now imposed on utilities.

Competition also may be looked to as a means of promoting efficient pricing. However, as will be discussed in later subsections of this paper, electric rates to ultimate customers generally are set on the basis of systemwide average costs and vary little, if at all, by time of use.¹⁴⁵ Short-run marginal costs are not translated into rates. Therefore, even if competition were to result in short-term bulk power being traded at prices closer to marginal cost, there is no reason to expect more efficient ratemaking to result. Finally, it is worth noting that the marginal costs of short-term bulk power transactions now are known so that if regulators wish to reflect such costs in rates, that can be done.

In sum, the conclusion must be that the existing central dispatch or economy power arrangements provide adequate means for optimizing the short-run operating efficiency of the industry. The creation of profit incentives to insure that efficient transactions are pursued diligently clearly is feasible within the present regulated framework. Economic efficiency does require that all generating utilities have access to economy power arrangements.¹⁴⁶ To the extent that access to such arrangements is not available,

¹⁴⁴Assume power were available at a given point in time having an incremental cost of 1.5 cents. A prospective buyer with a cost of 6 cents, but with a negotiated arrangement giving him 75 percent of the savings, would offer a profit of 1.125 cents [25 percent \times (6 cents - 1.5 cents)] per kilowatt-hour to the seller. A second buyer with a cost of 5 cents and a negotiated split-the-savings arrangement would offer the seller a profit of 1.75 cents [50 percent \times (5 cents - 1.5 cents)]. Thus, the power would be sold to the second buyer even though it would have been more efficient for the first customer's generation to have been displaced.

¹⁴⁵Time-of-day pricing, while in its infancy, is being explored widely. If such rates are to reflect the economic effects of short-term transactions, they would have to contain *energy charges* that vary by the hour. This would differ from most implemented time-of-day rates that create a fixed on-peak/off-peak differential to reflect varying capacity responsibility and perhaps, at best, variations in average-peak/off-peak energy costs over a season.

¹⁴⁶There may be circumstances under which it is not economically feasible for utilities to participate in such arrangements. For example, if the amount of generation involved is very small or if the operating costs of the two systems are very similar, the transactions costs associated with an economy arrangement could outweigh the benefits.

regulators now have the authority to order the admission of additional systems.¹⁴⁷ In short, there appears to be neither an existing efficiency problem nor any regulatory gap nor burdensome regulatory costs associated with present arrangements. Given this, we see no role for competition to plan.

Consider now emergency power transactions. The typical arrangement is for several utilities to interconnect their systems so that if an emergency occurs on any system, the generating units owned by all the interconnected utilities will respond to meet it. Electrically, this happens instantaneously and automatically regardless of any agreements. Anytime that load exceeds capacity on any part of an interconnected system, generating units throughout the network will respond (to the limits of their capabilities) to match resources to load. Whether emergency power will flow, therefore, is not the issue. Moreover, the typical arrangement is for emergency power to be priced at incremental cost (plus perhaps a 10 to 15 percent sum to cover transactions costs) or for the power to be returned in kind. Therefore, as long as systems are adequately interconnected, emergencies will be met and, typically, at an efficient price. We take it as given that generating utilities today have access to emergency support arrangements. The FERC has the clear authority and demonstrated willingness to mandate such arrangements in the public interest. The policy issue of interest here is what is required to insure that the terms of emergency arrangements do not discriminate among participants.

An interconnection to provide emergency power service typically is predicated upon each party's holding a specified amount of reserve generating capacity that can be called upon by any system in an emergency. Formulas for establishing required reserve margins differ. Each party may be required to hold as reserves a specified equal percentage of its load. A 20 percent equal percentage reserve requirement would mean that each system would have to provide 120 megawatts of generating capacity for every 100 megawatts of its peak load. Alternatively, reserve requirements are related to the relative sizes of the units owned by each party or to more formally calculated measures of each system's reliability.

In framing a policy to promote equal treatment of utilities in reserve sharing it is necessary to consider what it means to provide small systems with nondiscriminatory access to emergency sharing agreements. We have noted above that NRC conditions frequently require that reserves be determined on an equal percentage basis; that is, that a utility having 10 percent of the generation capacity would maintain 10 percent of the level of reserves required to meet the reliability criteria established. In our view such an arrangement is not necessarily nondiscriminatory, nor does it provide the appropriate signals to enhance efficiency. Individual systems may have the incentive to meet their reserve obligations with less reliable (and therefore less costly) capacity if there is no reward or penalty associated with the reliability of their own units. As an analogy, if a firm's workers' compensation payments were not tied directly to its own accident experience but only to the experience of a large group of firms, it seems likely that individual firms would pay less attention to pre-

¹⁴⁷See our discussion of this in Sec. 111-D.

venting accidents. Equal percentage reserve arrangements may in fact discriminate against systems that build high quality, reliable units.

On the other hand, the allocation of reserve burdens based on the calculation of separate reliability measures (e.g., loss of load probabilities) for each participating utility may discriminate against small systems with few units since the likelihood of loss of load will decline with the addition of more units of a given level of reliability. A more balanced approach may be to calculate reserve responsibility on the basis of the relative performance of individual units. Each system's reserve responsibility would be tied to the relative performance of its units compared with other similar units in the pool or throughout the country. Such a method would provide the appropriate efficiency incentives without discriminating between large and small participants.

The remaining class of transactions to consider are those we have labeled short-term sales of capacity and energy. Since load growth generally has fallen short of projections in recent years, many utilities find themselves with capacity in excess of their own needs. Other utilities, with high-cost oil or natural gas generation, may find it economical to make arrangements to purchase the temporary excess capacity of neighboring systems having lower cost units available. Such transactions also may occur due to the need to cover prolonged, unplanned outages of existing generating units, delays in bringing on new units, unanticipated load growth, or to permit the deferral of a new unit. In contrast to the hour-to-hour economy transactions discussed above, short-term capacity sales may be for periods of from a week to several years. Generally speaking, such transactions take place on an *ad hoc* basis at individually negotiated prices. Not infrequently, adjacent systems not having excess capacity to sell will assist the buyer by purchasing capacity from third party systems and passing it on to the ultimate buyer at or near cost plus a transmission fee. Essentially, this market may already be viewed as being competitive and we see no reason why any electric utility *having responsibility to meet part or all of its own capacity requirements* should be denied access to this market. Let us explain the italicized caveat.

Individual systems may meet their capacity requirements by owning their own units, by purchasing a defined block of power from other units or systems, or by transferring all or a portion of their responsibility to a firm wholesale supplier. In the latter case, the wholesale supplier will undertake the obligation to meet the customer's load and will include it in its load and capacity plans. (The wholesale customer's load will be considered a part of the supplier's load responsibility by any pool of which the supplier is a member.) Given the lead times required to adjust capacity plans efficiently, if the wholesale customer has the option of purchasing capacity and energy from other suppliers on a short-run basis, it will be able to impose excess capacity costs on its existing wholesale supplier by transferring its purchase elsewhere. Of more significance, in many cases, such a customer shift would contribute nothing to economic efficiency. If the two suppliers involved are part of a central dispatch or economy power arrangement, shifting a wholesale customer between them will in no way change the way in which the generating units are operated—precisely the same total load will be served at every instant in time

by the same set of generators operating at the same levels as before. The customer shift in the short run can result only in a financial shift, with the customer and perhaps the new supplier gaining and the old supplier, who undertook the obligation to meet the customer's load, losing.

In light of this, we can see no justification for permitting firm wholesale customers to shop for short-term capacity and energy while leaving the wholesale supplier with the cost burden of the capacity installed to provide service. Such shopping would only increase the financial risks associated with being a wholesale supplier, without creating any corresponding opportunity for enhancing economic efficiency. The wholesale customer would be placed in the position of having his cake and eating it too—that is, the supplier would carry the obligation to meet its capacity requirements, while at the same time the wholesale customer would retain the right to meet those requirements elsewhere.

In summary, it seems clear that the achievement of short-run economic efficiency requires that every utility owning generation have access to emergency and economy power arrangements.¹⁴⁸ If suppliers were required by regulators to interconnect with systems in their area and to make available their transmission facilities, where feasible, at a regulated rate to accommodate such arrangements among nonadjacent systems, competition might be able to play some role in shaping the terms and conditions under which economy power is exchanged. While such alterations could redistribute benefits among utilities, it seems likely that economic efficiency would suffer rather than be enhanced. Benefits can be redistributed toward smaller systems, if that is desired, without disturbing the efficiency produced by existing arrangements if regulators simply assure that all generating utilities have access to the present cooperatively negotiated emergency and economy power arrangements. With respect to other short-term capacity and energy transactions, we see no reason why all utilities not already served by firm wholesale suppliers should not be permitted to shop for such power, assuming that the transmission system can accommodate such shopping and that transactions costs do not outweigh benefits.

We thus are in general agreement with the drift of policy toward encouraging access to short-term power supply arrangements by all generating utilities, and with the absence of any discernable move toward substituting competition for cooperation as the determinant of the prices at which such transactions take place.¹⁴⁹ However, there is more that could be done in this area to promote efficiency. Under present arrangements, there is often no direct profit motive for a utility to make economy energy or short-term capacity sales. All of the differences between costs and revenues from these transactions may be passed forward through fuel adjustment clauses to the utility's customers. Under this circumstance the incentive for firms to participate aggressively in short-term transactions may be limited (particularly if capital outlays, recoverable only after a regulatory lag, are required to facili-

¹⁴⁸With the exception cited in note 146 above.

¹⁴⁹See our discussion of this policy in Sec. V-C.

tate such transactions). We propose that efficiency in short-run transactions be spurred by adopting a policy of allowing utilities participating in such transactions to flow at least a portion of the resulting savings through to their stockholders as profit.

D. *Direct Duplicative Competition*

Direct duplicative competition involves rivalry between two or more electric utilities to serve existing retail customers within a given area. For such competition to take place, there must exist at least two sets of wires and poles running down each street. Competition of this sort is strongly discouraged by state and local legislative and regulatory policy. Direct duplicative competition takes place to a significant degree in no more than several dozen communities in the United States. This reflects a widespread and long-standing recognition that the distribution of electricity is a local natural monopoly.¹⁵⁰

There are a number of interrelated characteristics that result in electricity distribution being a natural monopoly. (1) A direct physical connection is required between each supplier and each customer. If two rival systems are to be in a position to supply service to a customer, two duplicating sets of facilities must be built. (2) The amount of capital required to construct even the minimum physical connection is very substantial, both in absolute and relative terms. On average, for privately owned utilities nationwide, there is invested \$825 in electric distribution facilities for every residential customer served.¹⁵¹ Thus, the facilities required to serve a community of 100,000 population might amount to perhaps \$30 million. (3) The required connection is extremely long-lived (30-40 years) and once installed is basically immobile. Given this, electric distribution facilities idled by direct competition represent a virtually complete loss both to investors and to society. Moreover, raising at reasonable costs the large amounts of capital required for electric distribution facilities requires providing some assurance to investors that their investment

¹⁵⁰See our discussion of the literature in this regard in Sec. IV. In recent years, only one economist has reported statistical findings which question the local natural monopoly character of the electric industry. In two articles, Walter Primeaux has argued that while electric utilities may be local natural monopolies in theory, direct duplicative competition creates such pressures for efficient performance that, up to a point, the total costs actually achieved are lower in the face of such competition. Primeaux's work, which is based on data for the years 1964-1968, indicates that municipal systems facing direct duplicative competition achieved lower costs than those not facing competition as long as those systems had annual sales of 222 million kilowatt-hours or less. Approximately 92 percent of all publicly owned systems were in this size range and, according to the author, could be expected to achieve lower costs if direct competition were introduced. It should be noted that Primeaux's statistical results also suggest that the lowest possible costs are achieved by having monopoly service provided by firms selling over approximately 300 million kilowatt-hours per year. However, rather than urging that small firms be merged into larger firms in order to minimize cost, the author chooses to argue that direct duplicative competition among small firms should be fostered.

Primeaux's statistical study appears seriously flawed. Among the major problems are: (1) his study apparently examines only total operating costs, capital costs are ignored [Note that it is primarily capital expenses that one would expect to see increased by duplicative competition. These expenses appear not to be included in the Primeaux study.]; (2) the fuel cost variable used is based upon statewide average fuel costs for the state in which the municipality is located; (3) the cost of purchased power is measured only by the proportion of total power requirements purchased; and (4) market density is measured by the number of customers divided by the total square miles of the city, without regard to whether the municipal system operates throughout the city. For these and other reasons, Primeaux's study presents no credible argument to refute the local natural monopoly character of electric distribution. Walter J. Primeaux, Jr., "Some Problems With Natural Monopoly," *The Antitrust Bulletin*, Vol. XXIV, No. 1, Spring 1979, at 63-85; and *Id.*, "A Reexamination of the Monopoly Market Structure for Electric Utilities," Almarin Phillips, ed., *Promoting Competition in Regulated Markets* (Washington, D.C.: The Brookings Institution, 1975), at 175-200.

¹⁵¹U.S. Department of Energy, *Statistics of Privately Owned Electric Utilities in the United States*, 1979, at 34, 40.

will not be jeopardized by the introduction of direct competition. (4) The distribution of electricity is subject both to substantial economies of scale and economies of market saturation. To a large extent, both of these types of economies grow out of the fact that a significant portion of the total cost of distributing electricity is an "area coverage" cost. Such costs include those associated with distribution poles, conductors of the minimum standard size and strength, minimum-sized transformers, service drops to the customers' premises and meters. Since this large block of facilities and their associated cost is unrelated to the amount of electricity a customer takes, and only partially related to the number of customers served, it is obvious that for a single system to serve all of each customer's needs, as well as all customers in a given area, will result in substantial economies. Finally, electric distribution facilities impose substantial aesthetic and other costs on the community in which they are found. Because of these very substantial costs which are not borne directly by the electric utility, society rationally may choose to limit direct duplicative competition even if rival utilities were willing to engage in such competition. These characteristics all are shared in large measure by such businesses as natural gas distribution, water, sewer, local telephone and cable television systems, which also generally are deemed to be local natural monopolies.

Because the distribution of electric power has long been deemed to be a local natural monopoly, direct duplicative competition has been almost universally prohibited. An examination of the present characteristics of electricity distribution, as well as more recent theoretical literature addressing the conditions necessary for natural monopoly to exist, suggests no reason why the traditional view should be changed. Direct duplicative competition has no role to play in this industry.

E. Fringe Area Competition

Competition between utilities for the right to serve areas or customers located on the borders between systems is possible and, in a limited number of areas, may take place consistent with applicable state legislation and regulations. By fringe area competition, we refer to competition to serve customers located in areas where they can be served by the electric distribution facilities of two or more utilities. We distinguish this from the intentional creation of duplicative facilities to provide options to customers within a distribution area—that we consider to be direct duplicative competition. The significance of fringe area competition varies from area to area. However, it seems fair to say that such competition plays a minor role in the electric utility industry today.¹⁵² Even in those states where the boundaries of service territories are not fixed, regulations often exist to assign new customers to the utility with the nearest lines in order to eliminate duplication of facilities and minimize the investment required to provide service.

¹⁵²*Energy User News*, supra note 117.

The fringe area competition that exists, or may be feasible, seems unlikely to have a significant positive effect on economic efficiency for several reasons. First, and of major importance, as is true of wholesale rates, retail electric rates in the aggregate generally are based on systemwide average embedded costs. Such rates bear no necessary relationship to the efficiency with which a given supplier can serve new loads. Moreover, differences between retail electric rates to individual customer classes may reflect to an important degree, political and social objectives, in addition to systemwide costs. For example, an explicit public policy may be to set residential rates below average costs and recover the revenue deficiency through higher commercial and industrial rates. Given this, fringe competition would be influenced by utility size and customer characteristics as well as by differences in costs. A utility serving a relatively large amount of commerce and industry will have a broader base over which to spread the residential revenue deficiency and thus will offer lower commercial-industrial rates than a utility serving very little industry. Customers along the borders can be expected to seek service from the electric system with the lowest rates for their customer class, but there is no assurance that the efficient supplier will be the low-rate supplier.

If there is any benefit to fringe competition it is that it sometimes may force commissions to readdress whether maintaining noncost-justified rate differentials among classes is appropriate. As economists, we would prefer moving toward rates that more closely reflect marginal costs. If states are willing to let rates fully reflect marginal costs, the objections we raise to fringe area competition above would obviously no longer apply.

Fringe area competition cannot be expected to offer much of an incentive to suppliers to improve performance (even if reasonable rates of return are permitted). Typically, customers locating in the fringe area represent only an extremely small portion of the existing or prospective load served by a utility. Thus, there is not much at stake. Also, electric utilities generally are required to charge uniform rates throughout their service territory. This means that the only way the utility can offer more attractive rates to the relatively few customers in the fringe area is by reducing costs and rates across the board. That a utility would ever find it profitable to hold down rates throughout its territory in order to have a marginal influence on a small number of prospective fringe area customers seems unlikely.

Finally, as previously discussed, the electric utility industry for most of the past decade has been unable to obtain from regulatory commissions allowed rates of return as high as the cost of capital. Under those circumstances, there exists an active disincentive to take on new customers and raise the capital required to serve them.

On the other hand, it must be recognized that some fringe loads may be very attractive financially to municipal or cooperative systems. In the first instance, this may occur because when such systems purchase their requirements at wholesale, their perceived marginal cost of obtaining power to serve new loads will be equal to the embedded cost based wholesale rate. Second, when their rates are not regulated by state authorities, it may be possible for such

systems to engage in price discrimination to attract individual fringe area customers. It remains true, however, that unless prices reflect marginal costs there will be no systematic efficiency gain from fringe competition. Moreover, when the municipal or cooperative system obtains its wholesale power from the alternative server, there is little prospect of any efficiency gain.

In sum, the promotion of fringe area competition would seem, on balance, to offer no benefits. Efficient supplier choices are not likely to be made. Moreover, suppliers cannot be expected to strive for fringe area customers. On balance, the rule so often now applied to determine who serves in fringe areas — that is, the supplier with the closest facilities gets the customer — appears to represent the more reasonable course.

On the whole, public policy has been consistent with our economic assessment of the value of fringe competition. States generally have discouraged this type of competition. We are aware of no instance in which the promotion of fringe competition was the specific focus of a regulatory or judicial decision. However, in its price squeeze rulings, the FERC has elected to presume that this form of competition among others exists and is worthy of preservation. In our view, the better course would be to assign little or no value to fringe area competition in determining or implementing public policy.

F. Industrial Location Competition

In addressing industrial location competition, it is important at the outset to define clearly what such competition involves. Electric utilities traditionally have cooperated with various state and local industrial development agencies, banks, railroads, chambers of commerce and the like in efforts to attract new industry to the areas they serve. In so doing, in one sense of the word, they certainly have "competed" with utilities and other development groups in other parts of the country to attract customers. Such competition focuses on convincing industrial prospects that the area under consideration offers the firm and its employees the most attractive combination of economic and social amenities, including among other things, the best site, tax treatment, labor force availability and attitude, financing, transportation resources, natural gas availability, climate, school system and recreational facilities. If it goes no further than this, this is *not* the kind of competition we are concerned with because it relates in no significant way to electric utility performance. The competition we focus on is primarily price competition.¹⁵³

Price competition among electric utilities to attract industrial customers will be both feasible and desirable only if three things are true. First, customer site selection must be sensitive to the price of electricity. Second, the customer must be faced with prices which reflect the relative efficiency of various suppliers. Finally, utilities must have an incentive to compete for new loads. In most cases, as discussed below, none of these conditions hold.

¹⁵³Although reliability and adequacy of supply are valid concerns of prospective industrial customers, to the extent that electric utilities are interconnected to large grids that tend to equalize reliability and the availability of resources to all utilities in the area, these factors are less likely to play a significant competitive role.

With the exception of a few electric-power-intensive industries, prospective industrial customers generally will be relatively insensitive to electricity rates when making locational decisions.¹⁵⁴ This follows from the fact that electricity costs represent a very small part of the typical manufacturing firm's cost and to change the electric supplier by selecting a different location almost inevitably means changing other more significant cost determinants. In short, the supplier considering alternative locations does not have the luxury of minimizing electricity costs. He must seek to minimize total costs and, in this calculation, electricity is likely to play an insignificant role. As of 1978, for all manufacturing industries, purchased electricity costs amounted to only 1 percent of the value of shipments (that is, total costs).¹⁵⁵ For all industries other than chemicals and allied products (where the electricity/value of shipment ratio is strongly biased by the inclusion in the data of the government's three gaseous diffusion plants) and the primary metals industry, purchased electricity costs represented only 0.82 percent of value of shipments.¹⁵⁶ This means that even if the typical industry could realize, say, a 20 percent savings in electricity costs by choosing a different location, the resulting saving generally would amount to less than one-sixth of 1 percent of its total cost. Beyond this, a locational commitment is typically a long-term matter. It is the expected relative costs at alternative locations over a period of years which will govern such a decision. The difficulty in projecting the extent of long-term differentials further diminishes whatever effect on location there might be from electric rate differences.

It has been argued that despite the relatively small portion of business costs typically accounted for by electricity, if all other important location factors were equal in a given area, firms would take differences in electric costs into account in making locational decisions. As a theoretical proposition, this is, of course, undeniable. *If* all other locational factors were equal in the region, electric cost differences (if they were expected to persist over a long period) would become significant. Stated differently, if all else were equal, minimizing electric costs would be equivalent to minimizing total costs. However, studies we have conducted for a number of states show that, in fact, other things are never equal.¹⁵⁷ Indeed, other factors such as wage rates, property taxes and land costs generally vary to a greater degree within any given state or even within a given metropolitan area than do electricity prices.

¹⁵⁴These customers may be very concerned with the availability of sufficient electric power and energy to meet their needs and with the reliability of electric service, but see our discussion at note 153 above. It must be emphasized that studies showing that industrial electricity demand is sensitive to its price *do not* imply that firms move or choose location based on relative electric rates. "Competition" from conservation and from alternative fuels causes electric usage to be sensitive to price (elastic) whether the consumer is making a locational decision or not. The similarity among the measured elasticities of residential, commercial and industrial customers is consistent with our view that industrial elasticities are not evidence of locational competition. We are not aware of anyone who has seriously argued that residential customers make locational choices based on electric rates.

¹⁵⁵Derived from data in U.S. Department of Commerce, Bureau of the Census, "Fuels and Electric Energy Consumed," "Statistics for Industry Groups and Industries," *Annual Survey of Manufacturers*, 1978, M78(AS)-1, M78(AS)-4.1, Tables 2, 3.

¹⁵⁶*Id.*, supra note 155.

¹⁵⁷Such studies have focused on Indiana, Michigan, Wisconsin, Vermont, New York, Missouri and Texas.

In sum, we see no evidence to suggest that locational decisions will be particularly sensitive to electricity rates.¹⁵⁸ This remains true despite the fact that the real price of electricity has been rising. Certainly, in recent years, firms have focused increased attention on energy matters and therefore have sought out new ways to conserve electricity or alter the character of use so as to obtain more favorable rate treatment. But as long as electricity costs remain a small portion of total costs, firms are unlikely to pay much heed to such rates in making locational decisions.¹⁵⁹ If customer locational decisions are not sensitive to electric rates, there can be no rational basis for price competition among electric utilities.

Even if a substantial number of prospective industrial customers were sensitive to the price of electricity in making their locational choices, economic efficiency would be enhanced by competition for such customers only if their choices were based on correct price signals—that is, on prices that reflect the relative efficiencies of various suppliers in serving new loads attracted. As previously discussed, retail electric rates usually are based upon systemwide average costs and thus convey no information regarding the current or prospective efficiency of utilities in different areas. In addition, industrial rates increasingly reflect explicit regulatory commission decisions regarding the extent to which residential customers should be subsidized and which rate classes should bear the burden of financing the subsidy. If a government-owned or cooperative utility is involved in the competition, its industrial electric rates will reflect the subsidies made available to such entities, as well as their policies regarding cross-subsidization among customer classes. In the face of such price distortions, even if customer locational decisions were influenced significantly by applicable electric rates, there would be no basis for expecting loads to shift toward better performing utilities and thus spur an improvement in economic efficiency.

Finally, as has been shown earlier in this paper, when the marginal cost of supplying service exceeds embedded costs, the taking on of new loads at average cost based rates will create a need for new, higher cost capacity, thus driving up systemwide average costs and, after regulatory lag, all retail and wholesale rates. In order to minimize the rate of increase of electricity prices and to encourage conservation, some state regulatory commissions discourage utilities from engaging in activities designed to attract new industry.

¹⁵⁸Several studies conducted for the specific purpose of identifying factors that influence industrial location decisions have not found electric rates to be significant. For example, a September 1977 *Fortune* market research survey, "Facility Location Decisions," reported the results of 577 responses to a questionnaire aimed at covering factors which influence industrial locational decisions. All of the respondents were among the 1,000 largest U.S. industrial corporations. The cost of electricity was not even included as a factor in the final survey because preliminary results showed it to be insignificant. The important factors identified by the study were the presence of efficient transportation facilities, availability and productivity of labor and the availability of adequate energy supplies. A similar study conducted in 1977 for the *Wall Street Journal* entitled "Business On The Move," reached virtually identical conclusions. This study, which was based on some 2,000 responses to questionnaires, revealed as important factors the availability of labor, the availability of energy/fuel and the presence of highway transportation facilities. Again, electric utility rates were not even mentioned.

Beyond this, our own statistical studies examining a large sample of Standard Metropolitan Statistical Areas have revealed no significant relationship between industrial growth and the price of electricity.

¹⁵⁹Even if industrial electricity rates were to grow at a compound 20 percent a year rate for a decade, while other costs increased at only 10 percent annual rate, electricity costs would rise from 1.0 percent to only 2.4 percent of the typical firm's cost.

Even without such regulatory restrictions, electric utilities have disincentives to engage in price competition for new industry. First, since uniform rates generally must be offered to all customers of a given type throughout the utility's service area, in order to offer relatively attractive rates to prospective customers, rates to all existing and prospective customers in the same class would have to be held down.¹⁶⁰ It is unlikely that a utility would find it profitable to cut rates to 100 existing customers in order to attract one new customer. Second, as long as allowed rates of return are less than the cost of capital, utilities will strive to avoid expanding load, rather than seeking out new customers.

In sum, the prospects either for stimulating industrial location competition among electric utilities or for achieving a beneficial economic effect thereby are bleak indeed. As long as retail rates continue to be based on embedded average costs, publicly owned and cooperative systems continue to be subsidized, incremental costs remain above average embedded costs and regulatory commissions continue to allow below-market returns on capital, there is no prospect that rational utilities will compete for new business, or that choices made by customers among passive suppliers will promote economic efficiency. To the extent that industrial firms move in response to low electric rates, the main effect will be to redistribute benefits among customers as the new industrial customer gets a share of the embedded benefits enjoyed by existing customers in the new area, or to shift burdens among taxpayers if the industry is attracted by subsidized power rates.

In our discussion of public policy we noted that much of the FERC emphasis in "price squeeze" cases has been on differentials between wholesale and industrial rates and that this policy is predicated, at least in part, on a presumption that industrial location competition exists and should be protected. We believe this emphasis is misguided in view of the general insignificance of this form of competition. While we have no quarrel with the general concern of the FERC and the courts with discrimination between wholesale and retail electric customers, we see no virtue in focusing on the industrial rate as the specific center of inquiry.

In addition to the general insignificance of industrial location competition, there is also considerable doubt whether competition for large industrial loads between a wholesale supplier and its full-requirements distributor customer can serve any economic function. When a large industrial customer is taking its power and energy requirements at the same voltage as the distributor, the distributor's economic contribution is limited to providing a meter and perhaps a length of transmission line linking the firm with the wholesale supplier. Under these circumstances economic efficiency will not be advanced, and will more likely be reduced, by the imposition of the distributor as a useless middleman between the power supplier and the industrial load. Efficiency will be reduced to the extent that coordination and price signals between

¹⁶⁰Historically, electric utilities sometimes were permitted to have very narrow rate classes—such as a textile mill or primary metals class. Also, special contracts with very large or desirable customers were not uncommon. This reflected the desire of both utilities and regulators to expand load when incremental costs were below average. In recent years, however, there has been a strong trend toward consolidating rate classes and eliminating special contracts.

power supplier and ultimate customer are impeded by the presence of an intervening party.¹⁶¹ In short, large industrial customers should be viewed directly as bulk power supply customers operating on the same level as wholesale customers.

If industrial location competition is to play any economically meaningful role in this industry, at a minimum it will be necessary to give industrial customers proper price signals to use in their location and energy utilization decisions. One possible way to accomplish this would be to deregulate industrial rates for large *new* industrial facilities (i.e., those with demands in excess of 5,000 kilowatts) and require that utilities agree to wheel power to these customers (assuming that adequate transmission capacity is available and that the wheeling rate is compensatory). By limiting such competition to new customers there would be no disruption in the utility planning process and, if wheeling were made available, such customers could contract for long- or short-run power supply on the same basis as other bulk power market participants.¹⁶² The absence of regulation and a contractually limited service obligation should, with the exceptions noted below, result in power supply being offered at rates close to true marginal costs. This type of competition could be accomplished without a major structural change if state commissions agreed to deregulate rates to these large new customers in return for the wheeling offer.

For a competitive market for new industrial service to evolve, there would have to be some assurance that all potential suppliers would offer terms based on marginal costs. It would defeat the purpose, for example, if municipal and cooperative suppliers were allowed to offer lower rates only by virtue of their subsidies, the exercise of their preference rights to low-cost hydroelectric power, or based on the embedded cost wholesale rate of their supplier. Allowing "competition" on these bases would distort the allocation of resources by transferring the real cost of meeting the new load to others. Similarly, there would have to be some assurance that state and local authorities would not pressure utilities to offer terms below marginal cost in order to promote industrial development in their areas.

There would, in addition, be other drawbacks to promoting this limited form of competition. Industrial firms might be reluctant to change locations, even when the change was otherwise economic, if they would thereby lose their right to electricity at embedded cost rates. Limiting competition to new customers also would result in rate discrimination between old and new customers in the same industry that could affect the competitive balance within electric-intensive industries. A newly constructed aluminum plant, for example, would face electric costs considerably above those of established facilities.

We are unsure whether, on balance, such a policy change would be worthwhile but we do think it merits serious study. This is one of the few areas

¹⁶¹Coordination of the type and configuration of equipment installed and the timing of large electric motor loads can reduce costs and enhance reliability. Time-of-use pricing to industrial customers may likewise encourage efficiency and reduce overall costs. An intervening wholesale customer may not have the incentive or the knowledge to provide such coordination as efficiently as the wholesale power supplier.

¹⁶²Given adequate notice, it may be feasible to treat existing large industrial customers in a similar manner. However, this may create serious transitional problems for firms that would face marginal costs and whose location-specific investments limit mobility.

in which there is an arguable prospect that competition may be workable and in which it may be possible with "relative" ease to overcome major impediments which would disrupt its efficiency benefits.

G. Franchise Competition

Franchise competition refers to actual or potential competition between the utility presently possessing the right to own and operate the distribution system in a given community and other existing or potential utilities that may seek to take over the franchise. If, as is true in most communities, an investor-owned system presently provides service, there generally exists a way for the local government to condemn or fail to renew the utility's franchise. A municipally owned utility then could be created to take over service. Alternatively, a new franchise might be issued to a cooperative utility or to another investor-owned utility.¹⁶³ If a municipal utility presently provides service, it can be voted out of existence and an investor-owned or cooperative utility can be brought in to provide service.¹⁶⁴ If the voters in any given community could validly judge the relative performance of various actual and potential power distributors and if they had an effective means of changing distributors when the majority of the voters wished to do so, then, in theory, economic efficiency could be promoted by franchise competition. In the language of recent economic literature, if a natural monopoly market can be made realistically "contestable" by others who also seek to be the natural monopolist, then competitive performance can be achieved.¹⁶⁵ Indeed, if a sufficient degree of contestability exists, there is no need to regulate the natural monopolist. However, it must be recognized that making franchise markets contestable can impose significant costs if it disrupts bulk power supply planning. For reasons discussed elsewhere in this paper, the economics of this industry dictate long-term planning and coordination of power supply.

Franchise competition historically played an important role in the electric utility industry and in certain areas of the country, such as the Pacific Northwest, such rivalry is now active. It is undeniable that utilities threatened with the loss of their business, or a significant portion of it, are stimulated by the threat. If franchise competition were meaningfully related to the relative efficiency of the alternative servers, it would be economically desirable and worthy of protection. Our discussion of public policy toward competition indicated that the courts and regulatory commissions recognize this form of competition and have adopted policies toward retail/wholesale rate relationships and bulk power supply arrangements aimed at protecting it. However, serious

¹⁶³Whether a municipality could condemn the franchise and properties of one utility and then convey it to another seems questionable. However, when the first utility's franchise expired, presumably there would be no obstacle to enfranchising another private utility.

¹⁶⁴Cooperative utilities are limited to serving communities of 2,500 population or less.

¹⁶⁵Elizabeth Bailey, "Contestability and the Design of Regulatory Antitrust Policy," *American Economic Review*, May 1981, at 178-183. See also: W. J. Baumol and R. D. Willig, "Fixed Costs, Sunk Costs, Entry Barriers, Public Goods, and Sustainability of Monopoly," William J. Baumol, et al., eds., *Contestable Markets, Industry Structure, and the Theory of Value*, forthcoming; H. Demsetz, "Why Regulate Utilities?" *The Journal of Law and Economics*, April 1968, Vol. 11, at 55-65; and J. C. Panzar and R. D. Willig, "Free Entry and the Sustainability of Natural Monopoly," *The Bell Journal of Economics*, Spring 1977, Vol. 8, No. 1, at 1-22.

questions must be raised regarding both the pervasiveness of this form of competition and its value in the industry as it is presently structured.

It is axiomatic that rivalry to become or remain the natural monopolist serving an area at retail is economically beneficial only to the extent that it turns on the efficiency with which alternative franchise holders can provide service. For a number of reasons, given the present structure and institutional characteristics of the electric utility industry, we do not believe that franchise competition can or does generally operate to improve economic efficiency. The history of franchise shifts in the last several decades is consistent with this view.

Franchise competition cannot be expected to promote efficiency because numerous significant price distortions affect any franchise decision. Such distortions mean that there is little relationship between the costs of taking service from various suppliers as seen by the customer-voters of a community and the true relative costs of service. The first source of distorting price signals is the *apparent* cost advantage of municipal distribution utilities. The legal power to issue tax-exempt bonds, plus the savings flowing from the exemption of the municipally owned distribution entity from income taxes and from state and local property taxes, may provide a monetary incentive to create a municipal distribution system when the real economies of such a system are absent.

A second and more significant price distortion arises from the preferential access of municipal and cooperative systems to low-cost power produced by federal or state authorities. Historically, such power has been priced at extremely low rates due to the fact that the federal or state agencies need not bear any tax burden, that they have had preferential access to favorable hydro-electric sites and that a portion of the costs of their facilities can be allocated to flood control and irrigation, rather than being recovered through electricity rates. The fact that such power generally can be obtained only if the community has a municipally owned distribution system injects an extraneous distorting influence into the franchise decisionmaking process.

Third, the existing distributor's rates reflect its systemwide embedded costs rather than the marginal cost of service to the specific community. This means that when a franchise shift to a municipal distributor is considered, the economic comparison will contrast the present supplier's systemwide embedded costs with the costs of a new supplier acquiring the facilities in the particular community, at a price which may be as high as the reproduction cost of the facilities, and financing this investment at current interest rates. Alternatively, if a shift to an investor-owned utility is under consideration, what will be compared is the municipal system's existing rates based on the average cost of facilities in the community and the investor-owned utility's rates based on its systemwide average cost. Such comparisons will fail to reveal current or prospective efficiency both because they are based on embedded costs and because the investor-owned utility's rates will generally reflect the average cost of performing the distribution function in a number of communities throughout its service area.

Promoting competition among alternative franchise holders on the basis of the efficiency with which they can provide distribution service to a community

would require that, among other things, horizontally integrated utilities move away from systemwide uniform retail rates to a series of separate rates reflecting the distribution costs of service to each community. As long as rates are kept uniform throughout a utility's service area, there will be an uneconomic incentive for those communities where distribution costs are below the average to form separate utility systems. It seems unlikely that separate rates reflecting community-specific costs would be politically acceptable and such rates would certainly raise regulatory costs by greatly complicating rate proceedings.

Beyond this, given the institutional framework that exists today, there are substantial legal barriers to changing the holder of a franchise. The legal and transactions costs of effecting a change can be substantial. Condemnation proceedings, public hearings, votes of the citizens, and state and federal regulatory approval are frequently required. Indeed, regulators may oppose franchise shifts even when all the parties directly involved favor the change. All of these institution barriers impose costs and delays which may offset any potential efficiency benefits to be derived from changing servers.

To add to the difficulty of making a meaningful franchise decision, it must be recognized that, practically speaking, franchise decisions historically have been made on a once-and-for-all, all-or-nothing basis. No shifting back and forth among alternative distributors has taken place. This means that in order to make a rational decision, what must be weighed is the true expected costs of being served by various potential distributors over, say, the next 30 years. The difficulty of weighing such long-term costs and benefits, combined with the certainty of incurring large transactions costs in any effort to change distributors, suggest that franchise shifts will occur rarely and only when there is a clearly observable, long-term financial benefit associated with changing suppliers. History bears this out.

Within the last several decades, franchise shifts such as those described above rarely have occurred. Since 1960, only 35 new municipal systems have been created to take over the electric distribution service in a given community from another supplier. Of the 35 systems, 22 were created in communities previously served by integrated investor-owned utilities, two involved takeovers of small private utility companies operating only within the town, three were takeovers of facilities previously owned by private corporations, the remaining eight involved acquisition of United States Government, municipal or cooperative property.¹⁶⁶ Most important, in virtually every case, newly formed municipal systems were created explicitly to take advantage of low-cost federal preference power made available only to municipal or cooperative systems. In these cases, a clear long-term power supply benefit was identifiable and available only if a municipal system was formed to take over service. In short, there is absolutely no evidence to suggest that municipal systems have been formed in the last 20 years to take over service because the voters were convinced that the municipality could perform the distributive function more efficiently.

¹⁶⁶Edison Electric Institute, *Government Power*, 1977, at 35-36; American Public Power Association, *The People's Right to Choose*, April 1978, at 3.

During the period 1960 to 1978, 92 municipal systems were acquired by investor-owned utilities. Since 1970, however, only 25 such acquisitions have taken place.¹⁶⁷ The reasons underlying such acquisitions are not always clear. However, lack of scale economies appear to be a significant factor since almost all acquired systems served communities of 10,000 population or less; indeed, well over half of the systems acquired operated in communities of under 2,500 population. Beyond this, in at least a number of instances, the municipal electric utility historically had been used as a taxing device, with the result that funds that should have been used for repair and replacement of electric facilities had been siphoned away for other local government uses. Such municipal systems then tend to be offered for sale in a state of disrepair at a time when it is politically difficult to raise funds.¹⁶⁸ Thus, recent experience is that franchise shifts seldom occur and when they do, it is often for reasons unrelated to the efficiency with which the distribution function is performed.

Even if it were possible to eliminate the price distortions affecting franchise decisions and to minimize the transactions costs associated with attempts to change distributors, because of the nature of the distribution function, it is questionable whether significant efficiency gains would be possible. Distribution costs are largely fixed costs incurred in connection with financing distribution system investments in very long-lived and immobile capital facilities. Under these circumstances, a change in franchise will entail only a change of ownership of existing distribution physical plant. Since the physical distribution assets remain unchanged, it is only in operation and maintenance that a new server could make meaningful resource savings in the short-term.¹⁶⁹ Yet since distribution operation and maintenance costs represent only a small percentage of total electric system costs, achieving even a 10 percent reduction in operation and maintenance expenses typically would lead to a reduction in the cost of electricity of well under 1 percent. Thus, except in the very long run, the gains in real resource efficiency that could be expected to result, even if effective franchise competition were feasible, would be small.

In conclusion, given the present institutional characteristics prevailing in the electric utility industry, it seems clear that franchise competition takes place only in special and, until now, rather limited circumstances. When such rivalry does occur, the outcome bears no particular relationship to the achievement of greater economic efficiency. Franchises held by investor-owned utilities are realistically contestable only when the alternative is obtaining access to large-scale, subsidized bulk power sources available only (or preferentially) to municipal systems. In that circumstance, the franchise decision is wholly unrelated to the efficiency of electric power distribution. Municipal franchises are realistically contestable only when the municipal system is so small as to be unable to achieve distribution economies of scale or when the

¹⁶⁷*Id.*

¹⁶⁸It is worth noting that acquisitions of cooperative electric utilities by investor-owned systems are very rare, despite the small size of many cooperatives. A likely explanation is that the cooperatives' business is confined to the electric utility industry. Moreover, cooperative accounting is regulated by the Rural Electrification Administration.

¹⁶⁹This will, of course, depend to some extent on the rate of growth of the community. In a built-up community characterized by little new growth, distribution system investments will be required only to replace existing equipment as it wears out or to upgrade equipment to handle higher loads within the area. In a 10-year period, perhaps 30-40 percent of the equipment would be replaced. In a rapidly growing community, new equipment installed over a 10-year period could be more significant.

operation of the system is interfered with politically. While the substitution of another supplier could be expected to improve efficiency in that instance, whether or not the substitution will be made is a decision distorted by subsidies and uniform rates based on average costs. Within this setting, it makes no economic sense to weigh franchise competition heavily in determining public policy.

It may even make economic sense to *discourage* franchise competition when its result would be contrary to economic efficiency or another objective of public policy. Promoting the formation of municipal utilities or public power districts for the express purpose of obtaining low-cost preference hydro-electric power which otherwise would be more widely distributed to customers of investor-owned systems, is an excellent example of a policy which may concentrate the benefits of public resources in the hands of a relative few and result in relative prices of electricity that greatly distort its real cost of production. As previously noted, PASNY has recently proposed a change in the preference provision affecting its sales precisely to avoid this inequity and the resulting price distortion.¹⁷⁰

The goal of policy toward franchise competition should be to encourage it when franchise change is likely to promote economic efficiency. The rules of the game should promote fair competition but not a change in franchise for its own sake or for the capture of private benefit.

H. *Yardstick Competition*

The concept of yardstick competition, or competition by comparison, has been widely touted as one method of exerting pressure upon utilities to improve their performance. Yardstick competition can be seen as a supplement to regulation that can be particularly useful by providing an incentive for better dynamic performance over time.

Comparisons are not limited to rates, but can involve the technology or management aspects of performance as well. Basically, this type of "competition" may operate in either of two ways. An electric utility may engage in a self-comparison of its operations with those of other utilities. Alternatively, regulatory bodies and consumers may make such comparisons in an attempt to evaluate the relative performance of utilities. In theory, this provides a stimulus for utility managements to perform well in their functions as system planners, administrators and operators.

The scope for yardstick competition, however, is limited by the difficulties involved in making meaningful yardstick comparisons. Yardstick comparisons require that the measurements contrast systems similar in all respects other than those for which comparisons are desired or that comprehensive statistical adjustments for differences among utilities be made. The usefulness of the yardstick concept is limited when the size of systems, the nature of their service areas, the extent of vertical integration, their customer characteristics, their cost of money, or their access to fuel and transportation differ substantially.

¹⁷⁰PASNY, *A Report to the Governor*, *supra* note 105, at 12-16.

Yardstick competition has traditionally involved comparisons between public and private enterprise. The threat of government enterprise has in some cases been effective in stimulating adjacent investor-owned utilities to explore the elasticity of demand through lower rates. However, rate differentials between public and private power systems reflect such elements as size differences and, more important, subsidies, preferential access to low-cost bulk power, systemwide embedded cost differences and social or political objectives expressed through electric rates. The government yardstick cannot provide an accurate benchmark of what private performance should be as it reflects, in a large part, factors outside of management's control. Thus, comparisons between public and private utilities in particular are of limited usefulness.

The value of yardstick comparisons is questionable if some firms do not have equal access to coordination arrangements and are thus denied some of the benefits of pooling. More widespread access to coordination and pooling thus may increase the number of firms that can be compared. However, coordination undoubtedly diminishes the independent character of the participants. In fact, as common costs increase, much of the basis for comparison will be lost. With close coordination in planning and operation, all firms would enjoy the same reliability and have identical marginal costs except for such differences as are created by subsidies and preference provisions. Thus, closer coordination could make many of the yardsticks presently available less meaningful.

In conclusion, while the benefits of yardstick competition are widely proclaimed, there exists considerable doubt regarding the ability of utility managers or regulators to make meaningful interfirm comparisons. There is no evidence that efficient firms are rewarded or inefficient firms punished as a result of yardstick comparisons. Beyond this, yardstick comparisons may become even less significant as the degree of coordination of planning and operations increases among utilities. Greater coordination means that fewer differences will be observable between the performance of utilities, and utilities' costs and rates will reflect much more than the individual efforts of their managements.

We do not suggest that efforts to compare the relative efficiencies of electric utilities should cease. However, to be meaningful, such analyses must adjust for all factors beyond management's control, including among other things, service area density, nature of terrain, applicable environmental restrictions, overall utility sizes, differences in tax treatment, preferential access to power supplies and to a large extent, the availability and costs of fuels. If such adjustments can be made, utilities in all parts of the country can be compared. Thus, such "competition" will be feasible as long as there are enough utilities throughout the nation to permit valid statistical analyses to be carried out.

The development of public policy appears to recognize the nebulous nature of this type of competition. This is not among the types of competition which the FERC has assumed in its price squeeze decisions, nor have the courts

stressed its importance. We are aware of no public policy decision made solely on the basis of yardstick competition. In our view, this lack of emphasis is justified.

VI. CONCLUSIONS

The prospects for improving the performance of the electric utility industry by adopting a broad-brush policy in favor of injecting more competition into the industry are bleak, unless significant changes take place in the way the industry is structured and regulated. In particular, two pervasive features of the industry act as impediments to the achievement of economically meaningful competition. First, regulators base both wholesale and retail rates on average embedded costs, rather than on marginal costs. This both erodes the incentive of suppliers to compete and provides false price signals to buyers. Second, subsidies and preferences granted to publicly owned and cooperative utilities make it impossible to rely upon the marketplace to recognize and reward efficiency. The end result of promoting widespread rivalry between investor-owned utilities and subsidized entities can only be an expansion of government ownership, without regard to the economic merit of such a change in industry structure.

It is possible, we believe, to achieve some limited benefits of competition without basic changes in the way the industry is structured and regulated, but what is required is a finely honed approach that focuses directly on the efficiency effects of proposed policies, in lieu of a preoccupation with creating "competitors." The implicit or explicit assumption that improved performance will follow in this industry from the availability of more alternatives must be discarded. In particular, our analysis suggests the following as reasonable outlines for public policy within the present industry framework.

A. *Wheeling*

Public policy aimed at promoting widespread wheeling by electric utilities or converting utilities into common carriers is inappropriate as long as the possibility of shopping for average cost-based wholesale power exists and as long as significant subsidies are made available to publicly owned and cooperative utilities. However, given reasonable notice, we see no reason why either short- or long-term (unit) power, as distinguished from ownership entitlements, should not be wheeled to any system requesting it, providing of course that sufficient transmission capacity is available and its use is priced properly.¹⁷¹ The availability of unit power would give small systems access to bulk power on the *same* cost basis as the constructing utility. It would avoid the creation of uneconomic incentives for publicly owned or cooperative

¹⁷¹By reasonable notice we mean, for example, that a wholesale supplier whose sales would be replaced by a unit purchase be notified far enough in advance to adjust capacity plans and that the transmitting utility be given notice sufficient to schedule the transmission without imposing undue costs or impairing reliability. Transmission services should be priced at marginal cost to give systems the appropriate price signals. Measuring marginal transmission costs and charging prices based on them is likely to prove very difficult. Failure to face buyers with the real additional transmission costs of turning to remote power sources or using capacity in congested transmission corridors is likely to create serious distortions.

utilities to construct their own medium or small scale units or to obtain ownership shares in units constructed by others merely to exploit their subsidies further.

Congress has taken the most cautious approach on the wheeling issue. In our view, this caution is warranted. The provisions of PURPA clearly limit the ability of the FERC to order wheeling to displace wholesale sales. In addition, the requirement that mandated wheeling not upset the competitive balance could be construed as a limitation on the use of wheeling for the expansion of subsidized public power at the expense of efficiency. This is a construction of PURPA that we would favor. The final interpretation of these, and other provisions of this legislation rest, of course, with the FERC and the courts.

In our judgment, the NRC has approached the wheeling issue in the least sensitive manner. Mandating that wheeling services be furnished in order to permit municipal and cooperative systems to purchase ownership shares of generating units constructed by others, explicitly to allow those systems to take advantage of the subsidy, is economically indefensible. This is particularly distressing when the NRC rejects as adequate the provision of unit power as an option which conveys access to the same real economies to small systems, without providing the substantial bias of subsidized power.

The courts have no clearly defined position on wheeling. For example, they have never specifically addressed the obligation of an investor-owned system to wheel subsidized power when other alternatives such as unit power or wholesale power are available. *Otter Tail* and subsequent decisions do not appear to us to stand for the general proposition that a specific refusal to wheel from a subsidized power source, where this would convey an uneconomic advantage to an otherwise viable rival, would be found objectionable under the antitrust laws. We would urge the courts to continue to recognize the desirability of safeguarding the competitive process, in lieu of expanding the reach of the subsidy at the expense of competitive balance.

B. *Tariff Availability.*

Thus far, public policy has generally, and in our view correctly, limited the availability of embedded cost wholesale tariffs to wholesale customers in the geographic area of the supplying utility. As long as wholesale rates fail to reflect marginal costs, and thereby convey incorrect price signals, this is an appropriate policy. As this issue emerges, public policy should come out strongly and clearly against the promotion of bulk power shopping based on embedded cost wholesale tariffs. Utilities should not be required to extend the availability of such rates to supply extraterritorial loads or to replace self-generation. Indeed, in our judgment, the bulk power market could be made more competitive by *phasing out* embedded cost wholesale rates over a period of years and allowing all firms to shop freely to meet their additional and replacement capacity requirements. This might be accomplished by limiting the rights of wholesale customers to a share of the output of the embedded cost facilities of their present supplier and requiring them to contract for additional needs from any interconnected utility at prices reflecting the marginal

costs of these systems.¹⁷² We condition this recommendation, however, with the caveat that such shopping not be used to expand the subsidies of municipal and cooperative utilities by mandating ownership participation.

C. *Price Squeeze*

While we share the concern of the courts with wholesale/retail discrimination, the evolving implementation of this concern at the FERC makes little sense in two respects: (1) It has excessively concentrated on the industrial tariffs which are seldom the focus of actual competition and in many instances are quite irrelevant to wholesale customers whose actual and prospective loads are predominantly residential and small commercial; and (2) It has presumed competition and anticompetitive effect even when no actual or probable competition or competitive effect can be demonstrated. In our view, wholesale rates should be based on the costs of providing service and not modified for "competitive" reasons unless there is a clear demonstration that there actually is competitive harm or that the wholesale supplier has evidenced an intention to harm its customers. Our suggestion to move toward a free bulk power market by freezing the availability of embedded cost wholesale tariffs and providing free access to alternatives at the margin at prices reflecting marginal costs (discussed in more detail at VI-B above) would put wholesale customers and their suppliers on a plane of equality and thus mitigate price squeeze concerns.

D. *Pooling*

The emphasis of Congress and the courts on voluntary interconnections and pooling is appropriate. We share the view, frequently expressed in the literature, that access to coordination by small systems is needed to increase efficiency. In general, all generating utilities should have the right to enter pools with which they are interconnected on nondiscriminating terms or to obtain equivalent services. There are, however, some necessary caveats. Transactions costs should be considered in determining the form of membership. It may well be desirable for small systems to be admitted as a group, rather than individually, to keep the administration of pools manageable. In addition, we see no useful purpose in a policy of converting small wholesale customers into pool members primarily to provide them with the opportunity to obtain ownership participations which merely provide the ability to exploit their subsidies. The goal should be to achieve real efficiency and not artificially to lower the dollar costs of municipal and cooperative systems. For reasons discussed above, we believe that reserve requirements based on the relative reliability of the plants actually constructed are more likely to promote efficiency and equity than is the equal percentage reserve formula mandated in some NRC nuclear license conditions or the calculation of separate loss of load probabilities for each participant.

¹⁷²For a more detailed exposition of this proposal see the testimony of Joe D. Pace in Central Maine Power Company, Docket No. ER81-188 (December 10, 1981).

E. Access to Specific Facilities

Preference provisions which give publicly owned and cooperative utilities access to low-cost sources of power and energy that are denied to investor-owned utilities warp relative costs and rates and undermine the normal workings of the market. On this topic, some recent policy trends are encouraging while others threaten to exacerbate the problem. On the positive side, PASNY has questioned the wisdom of a policy which provides the great bulk of the benefits of low-cost hydroelectric power to customers in communities with municipal and cooperative utilities, when such utilities serve only 2 percent of New York State's rural and residential consumers.¹⁷³ To remove this imbalance, PASNY has proposed the creation of a state agency to purchase hydroelectric power from the Authority and make it available to all rural and residential users throughout the state, without regard to the form of utility ownership. Congress has likewise recognized the need to deal with the distorting influence of the preference provisions by including in the Pacific Northwest Electric Power Planning and Conservation Act provisions which will spread the benefits of low-cost federally produced hydroelectric power to residential and rural customers, whether served by investor-owned, municipal or cooperative systems. A complete phase-out of preference provisions would greatly enhance the prospects of economic efficiency and fair competition.

In contrast, the FERC's recent ruling that the Federal Power Act gives preference to publicly owned and cooperative utilities in the relicensing of hydroelectric facilities threatens a major shift toward government ownership and destruction of competitive balance in substantial segments of the industry. In this area, a legislative resolution may be required.

Another issue concerns provision of access by municipal and cooperative utilities to existing low-cost facilities owned by investor-owned systems. We believe the emphasis in such decisions should be on not interfering with the *process* of competition. A general policy of providing access to existing low-cost facilities merely because, after the fact, they have turned out to be low cost is wholly without merit. Such access represents a pure income transfer from the utilities that made correct choices (and their customers) to those that did not. It harms the competitive process and reduces the incentive for innovations and risk taking. If we adopt a policy of preserving utilities that made wrong choices (or whose choices through no fault of their own turned out to be wrong) this should be done through an explicit government subsidy rather than through appropriation of the facilities of utilities whose investments turned out well.

Whether small utilities that lack viable independent alternatives should be given the right to participate in newly constructed units on a nondiscriminatory basis is less clear cut. By nondiscriminatory we mean at prices which reflect the real costs of alternatives and which specifically do not operate through subsidies or preferences to give some participants lower costs than others. If such systems request participation while a unit is being planned (so that it can be sized to accommodate their needs) and if they are sold unit power (so their decisions and ultimate costs are not biased by artificial capital raising and tax advantages), their participation would be consistent with sound

¹⁷³PASNY, *A Report to the Governor*, supra note 105, at 13.

economic principles. Such participation would represent only another way of selling bulk power to small systems. Providing access to new facilities at prices reflecting their actual costs, together with phasing out embedded cost wholesale sales, as discussed above, would be consistent with a market in which each entity would face the correct price signals and could make bulk power decisions on a plane of relative equality.¹⁷⁴

F. Subsidies: What Can Be Done

We have explained at several points in our discussion that the subsidies available to publicly owned and cooperative utilities are a serious obstacle to the efficient operation of the bulk power markets. Treating all electric utilities equally in taxation would greatly increase the prospects for efficient decisionmaking and might also serve to encourage greater cooperation among the diverse elements of the industry. Achieving this equality has not been given the emphasis in the literature warranted by its economic importance. While we are neither legal scholars nor experts in tax law, we have given some thought to this issue and describe below a tentative proposal to achieve relative tax equality among electric utilities.

Rather than attempting the difficult, if not impossible, task of imposing taxes on cooperatives and public agencies, it may be more feasible to grant parallel tax-exempt status to private electric utilities. Specifically, this would involve exempting investor-owned utilities from federal corporate income taxes and exempting the interest and dividends they pay (as well as the interest paid by federally owned and cooperative utilities) from taxation as well. In itself, such a program would substitute one distortion for another. It would end the tax discrimination among electric utilities while extending the tax subsidy to the whole industry. Simply stated, electricity would be underpriced relative to other goods and services by the amount of the industry's tax advantage. Such tax exemptions would also result in a substantial reduction in federal revenue. We suggest, therefore, that the lost tax revenues be recouped through the imposition of a uniform national excise tax on electricity sales to ultimate customers. This tax would be imposed on sales to customers of *all* electric utilities whether the seller was federal, state, local, cooperative or investor-owned. If state and local governments were willing to grant similar exemptions from state and local taxes, the size of the excise tax would be increased to provide the funds necessary to compensate them for their lost revenue.

There are additional potential benefits of such a program beyond ending the distortions caused by the subsidies. The excise tax could be used to increase the cost of electricity to a level closer to its true marginal cost, thus promoting the conservation of energy resources and providing additional tax revenue. In addition, the tax-exempt status of interest and dividend payments could assist the financially troubled industry in raising needed capital.

¹⁷⁴There is one aspect of this proposal that continues to bother us, as economists. There would still be no profit motive to inspire firms to design lower cost and more efficient generation units. The "reward" for the utility that succeeded in attracting many participants in its units would be more partners to deal with. As long as unit power compensation is limited to proportionate sharing of unit costs, it is doubtful that such competition would result in enhanced incentives for constructing utilities. Perhaps, if there were enough sellers, compensation from unit power sales could be deregulated so that firms whose units were in demand could charge a premium over costs to reward them for the perceived efficiency advantages they would be sharing.