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COMPETITION AND INSTITUTIONAL CHANGE IN U.S. ELECTRIC POWER REGULATION

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Introduction and Overview

This essay describes the historical background and evolution of the electric power sector in the U.S. and explores alternative proposals to promote competition and to introduce incentives in rate design. The possibilities for change are most clear in the wholesale segment of the industry and are explored in some depth.

The discussion is organized in the following fashion. Part 1 gives the historical background and characterizes the current status of the electricity industry. Part 2 focuses on the development of a relatively unregulated wholesale power market based on competitive bidding mechanisms. Part 3 outlines alternative regulatory futures, the problems they pose and the constraints facing reform.

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Part 1. Historical Background and Evolution of the U.S. Electric Power Sector

I. Brief history of the origins of the system

The U.S. electricity system has been, and continues to be, a patchwork of state and federal regulations in a system with both private, municipal, and other government ownership. In this section we give a brief survey of the origin and early history of the public and private sector activities.

A. Private sector activities

The nineteenth century origins of the U.S. electricity system involved substantial technological rivalry between incompatible systems (Hughes, 1983). The technical configuration first promoted by Edison and his associates and used in the famous Pearl Street Station (1882) was based on direct current (d.c.). Westinghouse and others, starting later and with less financial backing, promoted alternating current (a.c.) primarily to achieve longer transmission and distribution distances. The technical advantage of a.c. was due to the comparative ease of transforming voltage to high enough levels that resistance losses from transmission were small. The d.c. technology was not able to achieve high voltage transformation for decades. Therefore, in the early development of the electricity industry, each technology had natural market niches. The d.c. systems prevailed in dense urban areas where they supplied lighting and power for electric railways (traction); the a.c. systems dominated smaller cities and towns, where their advantage in transmission over longer distances was clear.

By the early 1890s, an interface technology, the rotary converter, made it possible to blend the two technologies into a single coherent system. Eventually a.c. systems dominated because of their advantage in transmission. In the shorter run, hybrid systems could be operated using the interface technology, and therefore scale economies associated with mergers became possible (David and Bunn, 1988).

The system economies of large scale transmission began to be exploited in the period just before World War I. A significant step in this direction was taken with the experiments of Samuel Insull, former secretary to Edison and builder of the Commonwealth Edison Company, in Northern Illinois during 1910-1912 (McDonald, 1962). By linking together separate systems, load diversity improved the efficiency with which power could be produced. Small plants could be shut down and only the most productive equipment used. This saved fuel and maintenance cost, which more than offset the extra costs of transmission lines. Thus, geographic economies allowed for both lower rates and increased profits compared to more isolated operations. This example of pervasive network economies drove the early growth of the large scale electric utility beyond the confines of major metropolitan areas.

Scale economies could only be exploited systematically in a political regime that was stable enough to make raising capital feasible. The early history of competition in electricity was frequently destructive. Many private firms failed financially and were taken over by government entities. These seldom realized the scale economies that the larger private firms demonstrated. But the private firms faced a constant threat of franchise revocation by local political authorities. The political structure of state regulation with well-defined long term franchises began with the first commissions established in Wisconsin in 1906 and New York in 1907. By the 1920s over half the states had adopted this framework. Therefore, natural monopoly conditions could be exploited without undue political disruption.

With favorable conditions for growth, financing expansion became a key constraint. Electricity is a very capital intensive industry. Retained earnings as a source of finance were insufficient for the expanding demand of the market, and the need for external finance became critical. Insull was an innovator in this area as well as in technology. He pioneered the mass sale of common stock to customers during the 1920s and the broadening of debt markets beyond the New York financial community (McDonald, 1962). At the same time equipment vendors also acquired a significant quantity of securities from utilities as payment for goods and services. Utilities proliferated securities through holding companies, some of which were controlled by vendors such as General Electric.

B. Government ownership

Throughout the history of the U.S. electricity system there has been competition among various forms of ownership. The investor-ownership model became predominant, but not without several different kinds of government ownership achieving niche roles. We begin this section by characterizing these different government roles.

The federal government has played a significant, but always limited, role in electric power. Federal authority functions principally at the wholesale level. Constitutional authority over interstate commerce evolved into an apparatus of federal regulation covering most wholesale transactions, including those occurring between parties strictly located within one single state. Moreover, the federal government has ownership rights over most hydroelectric resources. The

Federal Water Power Act of 1920 (P.L. 66-280) codified federal powers. This act established the Federal Power Commission (FPC) to issue licenses for non-federal hydroelectric development, and to regulate prices for wholesale transactions. It also embodied the principle of preferential allocation of surplus federal power sales to municipalities.

In the 1930s the federal government encouraged the growth of rural electricity service by subsidizing the formation of rural electric co-operatives. The Rural Electrification Administration (REA) provides loans, federal power preference and tax exemption to electric power organizations in rural areas and small towns. REA co-ops are also exempt from state and federal regulation. This initiative contributed to growth in the proportion of farm homes with electricity, which rose to 35% in 1941 from a level less than one-third of this in 1932 (Census).

The value of the federal power preference grew with the expansion of Bureau of Reclamation dams in the western states. In 1936, the Hoover Dam began generating. Grand Coulee, the largest dam in the U.S. was completed in 1941. The U.S. Army Corps of Engineers build flood control dams producing additional power for preference customers. Under the Tennessee Valley Authority Act of 1933 (P.L. 73-17), the federal government supplied power to municipalities and rural co-operatives in the region. Hydroelectric construction by the federal government continued during World War II, and only slowed during the 1950s with a change in public policy and a lack of new major sites.

Municipal ownership of utilities seldom evolved into large systems. As cities grew they typically gravitated into the domain of the investor-owned sector. Two prominent exceptions are Seattle and Los Angeles. In both cases, the early growth of the system was facilitated by the development of regional hydroelectric resources either under direct municipal control, or later as preference customers of federal projects. Municipal ownership had long provided a competitive constraint on the prices of private utilities. This constraint was limited by the municipality's opportunities to realize scale economies, which were largely determined by its geographical boundaries.

II. Regulatory Institutions

A. Origin and Evolution of the Investor-Owned Model

The regulatory structure governing the investor-owned segment of the U.S. electricity system involves three basic features: (1) geographically distinct franchise monopolies operated by vertically integrated firms, (2) price regulation intended to limit monopoly profits, and (3) the obligation to serve customers. Administrative agencies of state government typically determine franchise boundaries, control prices and enforce service conditions.

There is considerable ambiguity about the origins of regulation. Was its fundamental purpose the control of monopoly power or was it a mechanism to facilitate raising capital? What evidence there is points more to the latter than to the former. The system of state regulatory agencies was promoted by investor-owned firms as a reform of the political corruption which dominated the purely local franchising process. The resulting system benefitted the investor-owned utilities and their shareholders as much or more than the consumers in whose name these reforms were nominally adopted (Jarrell, 1978). Clearly the sale of securities to finance electric power system expansion grew substantially in parallel with the growth of regulation. While regulated prices did show a decline during the 1920s, the rate was slower than corresponding decreases for electric utilities in states without regulation (Twentieth Century Fund, 1948).

Throughout the first decades of regulation, most administrative issues involved accounting and service standards, and the issuing of securities. Growth in demand and capacity was financed by sales of common stock and bonds. Frequently, firms were assembled into holding companies which could be controlled by rather small percentages of stock. The holding companies were able to generate significant revenues from the operating companies through services contracts of various kinds. With the financial collapse of the 1930s this system came under severe stress. Revenue from the operating companies for services declined significantly, and holding company stock prices fell considerably. The system of holding companies was re-organized under federal legislation which rationalized the structure, but made subsequent consolidation of the industry more difficult.

The price deflation of the 1930s stimulated reductions in utility prices at the instigation of state commissions. Previously, utilities initiated the rate review process and determined the timing and magnitude of price reductions that were justified by productivity increases. When state agencies initiated the price reduction process, it was motivated by the perception that there were substantial excess profits (Wainwright, 1961). This shift in political initiative raised the question of defining the appropriate profit standard which was only resolved by federal adjudication. The Hope Natural Gas and Bluefield cases set the standard of "just and reasonable" profits as the norm for regulated industries (see Bonbright, 1961).

B. Balance Between Public and Private Sectors

Throughout the post-war period the struggle between government ownership and the investor-owned segment continued. The issue reached the level of national political debate in the presidential election of 1940, when the Republican party nominated Wendell Wilkie, a vigorous opponent of government ownership, whose business career was associated with a large multi-state holding company. The defeat of Wilkie did not end the debate. The election of Eisenhower in 1952 signalled the end of expansion of the federal system. Projects started previously were completed in the 1950s, and subsequent development stopped in the following decade. The public and co-operative segment continued to expand. The configuration of ownership structure in 1989 is illustrated in Table 1. This shows the dominant role of investor-owned firms. The small size of municipal and co-operative utilities is evident from either the average level of sales or capacity per utility. In terms of capacity, the average investor-owned firm in 1989 had 1973 MW, compared to 36 MW per publicly-owned utility and 26 MW per co-operative. A similar disproportion is evident by comparing average sales.

The magnitude of the federal hydroelectric subsidy to publicly-owned and co-operative firms can also be estimated from these data. The total generation of these two sectors is 369 billion Kwh, and their total combined sales is 562 billion Kwh. The gap must be made up by purchases either from low-cost federal generation or higher cost wholesale supply from investor-owned firms. The federal sector shows an excess of production over retail sales of 171 billion Kwh. This power is sold at an average cost of 1.6 cents/Kwh to the publicly-owned and co-operative segments (EIA, 1991a). This is at least 4 cents/kWh less than the open market cost for long term firm power supply. Therefore the transfer payment is about $7 billion, or roughly 20% of the combined revenue of the publicly-owned and co-operative segments.

Table 1. Structure of the U.S.Electricity Industry, 1989

	Retail Sales (Thousand GWh)	Generation (Thousand GWh)	Surplus (Deficit) (Thousand GWh)	Number of Utilities	Capacity (GW)
Investor-owned	2032	2192	160	265	523
Publicly-owned	372	246	(126)	1994	71
Co-operative	190	123	(67)	956	25
Federal	53	224	171	10	65

III. Description of the Electricity System since WWII

A. Fuel Use

The dominant fuel used for power generation in the U.S. is coal. Limited hydroelectric resources and growing concern about environmental impacts of coal-fired power plants led to an expansion of alternative fuels. The two main alternatives were nuclear and petroleum-based fuels. The first sizable contribution from nuclear power occurred in the late 1960s. In the fast growth period of the 1950s and early 1960s, a large fraction of incremental capacity was fired by oil and natural gas. By 1970, before nuclear plants became a significant factor, oil and gas generation represented around 40% of all production (EEI).

The expanded uses of oil and gas fuel for power generation was economic until the oil price shocks of the 1970s. During this decade fuel related costs increased dramatically, making the need for substitutes apparent. Unfortunately, the principal solid fuel technologies, coal and nuclear, encountered substantial siting and construction delays just when they were needed most. By the early 1980s, projects based on these fuels came into operation and substantially reduced the share of oil and gas-fired generation. With the fall in world oil and gas prices starting in 1986, however, the shift to solid fuels may have been excessive. By 1989 only 15% of the fuel mix was oil and gas. The slow adjustment of capacity to changing fuel prices is a serious problem of large-scale power generation technology.

Table 2. Capacity and Generation by Fuel Type, 1989

	Capacity (MW)	Capacity(%)	Generation (GWh)	Generation (%)
Coal	296,614	43.3	1,553,061	55.8
Oil-Steam	50,967	7.4	151,111	5.4
Oil-Turbine	27,018	3.9	7,207	0.3
Gas-Steam	94,150	13.8	245,057	8.8
Gas-Turbine	22,994	3.4	21,542	0.8
Hydroelectric	90,467	13.2	265,063	9.5
Nuclear	98,161	14.3	529,355	19.0
Other	4,248	0.6	11,309	0.4
Total	684,619	100.0	2,784,304	100.0

B. Technological Change

Throughout most of the post WWII period there was substantial technological improvement in the electricity system. The size and efficiency of generating units increased. The capacity of transmission lines increased; higher voltages reduced losses and allowed longer lines. All of these trends marked continuation of previous experience. The broad outlines of these developments are summarized in Joskow (1987). We briefly highlight particular details below. In the post-war period, coal-fired steam turbines experienced falling capacity costs and increasing operating efficiencies until about 1965. In the post-1965 period, the real cost of capacity approximately doubled and operating efficiency did not change. The capacity cost increases were due largely to more stringent environmental regulation, but declining construction productivity and increased construction time also played a role. The data also show that utilities with more experience in building complex coal plants achieved lower costs, which suggests that overall efficiency would have been better if a small number of more experienced firms had a more dominant role. Finally, Joskow argues that the pursuit of scale economies "overshot" in coal generation, particularly regarding the "super-critical" boiler technology. These plants ended up having higher unit costs of production than smaller scale "sub-critical" boilers, principally because of poor operating reliability.

Commercial nuclear power was introduced to the electric power industry after substantial intervention by the federal government. The federal role supported private development of this technology under the Atomic Energy Act of 1954 (P.L. 83-703). The Price-Anderson Act (P.L.85-256) limited private liability in the event of catastrophic accident, thereby facilitating private investment. The federal government continued to support the nuclear industry with a substantial R&D effort throughout the post-war period. The economic promise of nuclear power did not materialize despite these efforts. Construction costs exceeded estimates by substantial amounts, although again there was a large variance. A few firms performed particularly well with regard to cost; several smaller utilities had disastrous experiences managing such complex projects.

Important technological developments occurred in the gas turbine segment of the industry (Williams and Larson, 1989). The traditional use of this technology was for peaking operation where its low capital costs and high operating costs made it ideal for limited service. With the emergence of the private power market in the 1980s, a new generation of more efficient turbines began to be used in baseload cogeneration applications. Further improvements led to highly efficient combined cycle plants that have both modest capital costs and relatively low operating costs. Due to the efficiency of combustion and the use of natural gas, these plants have relatively limited environmental impacts. Another advantage of the new gas turbine technology was its greater flexibility with respect to planning. Construction and installation times are much shorter than for solid-fuel generation, and the units come in smaller sizes (25-200 MW) compared to the 1000 MW size that was typical in the 1970s for coal and nuclear plants. Both of these features make it easier to adjust capacity to changes in expectations with regard to demand and relative fuel cost.

C. Retail Rate Structures

C.1. Administrative Procedures

Prices for electricity are set through a process that is designed to collect the revenues determined in an administrative hearing to be necessary to cover total costs. It is common for this revenue requirement to be determined by two separate kind of hearings, one oriented to fuel costs and one oriented to all non-fuel costs. This distinction originated in the 1970s as a response to the price shocks in the world oil market, and what is generally known as "fuel cost adjustment" hearings have remained a permanent feature of the administrative process. The fuel adjustment hearings involves a substantially lighter evidentiary burden than the adjudication involving all other costs. The rationale for this difference is that fuel costs are largely out of the utility's control. Issues in a fuel adjustment proceeding involve the utility's efforts to minimize operating costs by efficient fuel contracting and maximizing the opportunities for wholesale purchase. We discuss the wholesale markets further in Section D below.

The non-fuel portion of electricity revenue requirements includes overhead and administrative costs, certain kinds of operation and maintenance costs and the fixed costs of capital investment. Once issues associated with determining the appropriate level of these costs have been resolved, the rate-making process involves several steps designed to allocate them to customer classes and collect the allocated costs through tariff design. The institutional practice of ratemaking has traditionally been oriented to accounting issues, and relatively little attention has been devoted to marginal costs. Occasionally, economists are appointed to regulatory commissions, and then more emphasis on marginal cost may occur. An interesting account of such a case is given in Anderson (1981), which describes the tenure of Alfred Kahn on the New York Public Service Commission.

The main function of marginal costs in rate-making lies in defining time-of-use rates for large commercial and industrial customers. A time-of-use rate is an approximate representation of systematic variations in short-run marginal cost. Usually these rates have two or three diurnal time periods, and two seasonal components that result in four or six different prices for energy during the year. The goal is to embody the peak/off-peak distinction into prices for those customers whose consumption is large enough to justify the extra metering cost. Usually such customers are also large enough so that they also have demand-metering. The resulting tariffs will have a demand component and time-of-use energy charges.

C.2. Historical Results

Before turning to the current structure of prices, it is useful to review the long term historical trends. These are summarized in Table 3, which shows average nominal prices per kWh for residential customers and for all customers sampled over five year intervals from 1930 to 1990 and the average rate of change of prices between the sample intervals.

Table 3 shows the striking long term decline in electricity prices, reflecting the productivity growth characterizing the industry up until the 1965-1970 time period. The rate of decline was greater for residential rates than for all customers, because, in part, residential prices started at much higher levels. The gap between residential and non-residential rates in the early 1900s is consistent with profit-maximizing behavior, which would have required low prices to induce industrial consumers to switch to electric power. The price increases, starting in the 1970-1975 period, were distributed less to residential customers than to other customer classes. The implications of the price trajectories summarized in Table 3 will be discussed in Section IV below.

Table 3. Average Electricity Prices: 1930-1990

Year	Residential Rate (¢/kWh)	Average Annual % Change	All Customers Rate (¢/Kwh)	Average Annual % Change
1930	6.0		2.7	
1935	5.0	-3.6	2.4	-2.3
1940	3.8	-5.3	2.0	-3.6
1945	3.5	-1.6	1.7	-3.2
1950	2.9	-3.7	1.7	0
1955	2.7	-1.4	1.7	-0.6
1960	2.5	-1.8	1.6	-0.6
1965	2.3	-1.8	1.6	-0.1
1970	2.1	-1.4	1.6	0
1975	3.2	8.9	2.7	11.2
1980	5.1	9.8	4.5	10.7
1985	7.4	7.6	6.5	7.6
1990	7.8	1.1	6.6	0.4

C.3. Current Price Structure

Although the rate making process is supposed to produce prices that are not discriminatory and are based on costs, there are clearly exceptions to these principles. Some states have explicit subsidy policies aimed usually at low-income residential customers, sometimes at all residential customers. More often, subsidies are implicit. Agricultural customers frequently pay low prices that are difficult to justify on a cost basis. Economic development arguments are sometimes used to rationalize low prices to specific industries, or to specific geographic regions. Table 4 below summarizes average electricity costs for 1989 by customer type for the four main ownership structures.

Table 4
Average Revenue (¢ per kWh) by Class of Ownership and by Sector, 1989

	Residential	Commercial	Industrial	Average
Investor-Owned	8.0	7.3	4.7	6.6
Publicly-Owned	6.3	6.4	4.7	5.8
Co-operative	7.4	7.2	5.0	6.9
Federal	5.5	5.7	4.0	3.6
Average	7.6	7.2	4.7	6.5

This table shows the different rate policies and average costs of the investor-owned segment, the publicly-owned segment, co-operatives and the federal government. Because government-owned utilities pay no taxes and have no equity capital their rates can be expected to be lower than investor-owned firms. There are also significant operating subsidies from the federal sector to the municipal and co-operative segments. As Table 1 indicated, federal power sales to ultimate customers are small. The bulk of federal sales are wholesale transactions based on the preferential allocation of hydroelectric generation at very low cost. This explains why the average rate for federal power is lower than all rates to end-use customer classes.

Table 4 also indicates a tendency toward price discrimination against commercial customers. In the case of both publicly-owned and federal rates these customers pay the highest prices. For investor-owned and co-operative firms residential rates are somewhat higher than commercial. The differentials, however, are too small to be based entirely on cost. The typically higher voltages and higher load density of commercial as opposed to residential customers would suggest bigger price spreads. In all likelihood, the commercial customers rates are more determined by their relative bargaining weakness compared to the political power of residential customers and the economic power of industrial customers.

D. Wholesale Markets

There is a substantial amount of wholesale trade among electric utilities. It is organized into two kinds of markets, one for firm power and one for short-term economy exchanges. Firm power transactions are usually between adjacent utilities where transmission interconnections are direct. The term "firm" means that the seller has an obligation to deliver that can only be breached under a limited set of circumstances, usually involving the reliability of his system, and not including opportunity costs. The buyer of firm power treats it operationally as if it were his own unit. It contributes toward his reliability objectives in the short and intermediate term, and is part of his resource plan. At the other extreme, economy exchanges are often contracted only on an hourly basis. They imply no commitment from the seller, and cannot be relied upon by the buyer to meet reliability goals.

In practice, there is considerable gradation between these two extreme types of transactions. Some economy transactions may go on for weeks or even months at a time. Some firm exchanges may only last for one year, as opposed to five or ten year periods. A common pricing distinction involves the payment of fixed capacity or demand charges. When these are paid they usually imply the no-interruptibility condition, and therefore define a "firm" relationship. As a practical matter, however, when there is excess supply, interruptibility is moot and economy transactions may essentially be equivalent to firm. One additional reason why economy transactions may not qualify as firm is that delivery from seller to buyer may require transmission service from an intervening utility (called "wheeling"). There are only limited wheeling obligations among utilities, and in most cases such arrangements are interruptible. Under such circumstances, the energy transaction cannot be firm.

All wholesale transactions are regulated, in principle, by the Federal Energy Regulatory Commission (FERC), which is the successor to the FPC. In practice, FERC exempts transactions conducted under formal arrangements known as power pools because the terms and conditions of trade in these cases are defined by rules that are reviewed by FERC. The term "power pool" covers a variety of institutional arrangements. Essentially a power pool is an organized exchange where trade is either directed (in the most centralized case) or at least coordinated among the members. Pools commonly use standard pricing rules, the most common of which are "split-savings" or "cost plus mark-up."

Statistics on the magnitude of wholesale markets and their composition are complex. Accounting practices are not standardized. Estimates of the size of "economy energy" transactions range from roughly 10% of sales in the New York Power Pool, to about 1% of sales for the Western Systems Power Pool (Strategic Decisions Group, 1991). At the other extreme, the total amount of purchased power (or alternatively, "Sales for Resale") reported by EIA at the national level is 35-37% of all production (EIA, 1991a). The larger figure includes the full spectrum of transactions including sales from private producers to utilities (about 3.5% of production), wholesale firm sales from investor-owned utilities to government -owned utilities, wholesale firm sales from government entities to public and private utilities (at least 6% of production), and the whole range of firm and non-firm trade among investor-owned firms. The most detailed breakdown of the "Sales for Resale" data is for the year 1986 (EIA, 1990).

E. Investment Behavior

Mismatches between supply and demand were particularly severe during the 1970s and 1980s as the size of generating units grew and construction lead time lengthened. At first, the issue was potential capacity deficiencies. During the 1970s, the requirements for environmental review of power plant construction became much greater than they had been previously. The Supreme Court ruled in 1971 that nuclear power plant proposals had to file environmental impact reports before they could receive construction permits. This caused considerable delay between planning and construction. Repeated changes in safety requirements, particularly following the accident at Three Mile Island in 1979, lengthened construction and added to its cost. The oil price shock of 1973-74 had the effect of improving the economics of coal and nuclear power projects, but the contemporaneous rate increases also reduced demand growth. By the late 1970s, short-run marginal costs were high, reserve margins were low, and the backlog of large-scale construction projects was substantial.

This process began to reverse itself in the 1980s. Oil prices began a gradual decline. Demand growth stagnated due in large part to a severe economic recession. Utilities began to cancel plans for capacity expansion. In the 1972-1974 period utilities ordered 107 nuclear plants. Between 1975 and 1978, 38 were canceled and another 48 were canceled in the 1979-1982 period (EIA, 1983). Despite these efforts to bring supply plans in line with reduced demand, there was considerable excess capacity during the mid-1980s. The cost disallowances described briefly in Section IV were based in part upon excess capacity considerations. This experience had a considerable effect upon the incentives of utility management.

Table 5 shows the capacity balance for the period 1966-1990. Reserve margin is used as the best single summary statistic measuring the adequacy of capacity relative to demand. A conventional industry rule of thumb for reserve margin (measured as the percentage of capacity above peak demand) is 20%. This is often related to some probabilistic measure of outage risk, but the appropriate outage risk level is usually specified by convention, rather than by economic criteria. The Table 5 data are at the aggregate national level. The non-coincident peak means just the sum of the highest demands, regardless of when during the year it occurred. As such, these data conceal regional variations, and probably understate effective reserves, due to potential capacity sharing when peak loads occur at different times. Table 5 clearly shows the excess capacity period from 1974-1989.

Table 5. Aggregate Capacity, Peak Demand and Reserve Margins

Year	Capability (million kW)	Non-Coincident Peak	Reserve Margin (%)
1966	241	204	18.1
1967	259	214	21.0
1968	280	239	17.2
1969	301	258	16.7
1970	328	275	19.3
1971	354	293	20.8
1972	383	320	19.7
1973	417	345	20.9
1974	444	349	27.2
1975	479	356	34.6
1976	499	371	34.5
1977	517	395	30.9
1978	546	408	33.8
1979	557	409	36.2
1980	570	437	30.4
1981	595	439	35.5
1982	593	420	41.2
1983	596	447	33.3
1984	615	459	34.0
1985	645	470	37.2
1986	649	480	35.2
1987	648	497	30.4
1988	675	529	27.6
1989	681	523	30.2
1990	685	558	22.7

For most of its history, the electric utility industry had among the largest demand for investment capital of any industry in the U.S. The tendency to invest large sums of capital has been attributed to the form of regulation, which provides earnings in proportion to investment cost. A formal argument that this form of regulation led to an inefficient use of capital was the classic paper of Averch and Johnson (1962). These authors argued that when the regulator sets the allowed rate-of-return above the cost of capital that the utility will utilize more capital than if it were unregulated, and will choose an inefficiently high capital/labor ratio for its level of output. Most tests of the Averch-Johnson hypothesis, based on data before 1973, have demonstrated a bias toward capital (see, for example, Courville (1974)). However, this could be explained by factors other than rate-of-return regulation, such as risk-averse behavior by managers.

In the period following 1973 there is considerably more ambiguity both about the applicability of the assumptions of the Averch-Johnson analysis and about the behavior of the utilities. In the period between 1973 and the mid-1980s, electric utilities may well have earned less than the cost of capital. Yet the inertia of their investment program was so substantial, that their demand for capital (even net of canceled projects) remained at historically high levels. During the period when the bulk of the 1970s generation of power projects were complete, and cost disallowances began to occur, utility management began to adopt a "capital aversion" strategy. While excess capacity eliminated the need for new investment in many areas, this was not universally true. Thus, in some segments of the industry the opposite of the Averch-Johnson behavior seems to have occurred in recent years, with only the most minimal capital investment taking place. This consists of either a decision to purchase capacity from others, or investment in low-cost combustion turbines rather than more capital-intensive baseload facilities. It is unclear whether this is a long-term phenomenon or only a transient phase. For the most part, the financial condition of investor-owned utilities has improved. The allowed return may now be higher than the cost of capital (the necessary condition for Averch-Johnson behavior). This would argue for a return to more standard behavior.

Table 6 gives aggregate data on the capital expenditures of the investor-owned segment from 1973-1990. The tremendous inertia of the commitment to nuclear power is indicated by comparing this data with Table 5. At the very time when price induced declines in demand were increasing excess capacity, the capital budget of the industry was escalating substantially. The data in Table 6 are given in nominal dollars, so the real level of these effects is less, but still substantial.

The Table 6 data are also interesting in the more recent period. The rapid decline in generation sector investment explains most of the decline in total construction. The only off-setting effect is an increase in distribution system investment, which increases by 50% from 1985 to 1990. These data suggest that while the vertically integrated firms are losing control of the generation segment (see Part 3), they are relatively free to shift investment attention to the distribution segment, which is free from competitive pressures. There is no incentive to increase transmission investment because it would inevitably end up strengthening the competitive position of independent generators seeking wider markets.

Table 6. Construction Expenses of Investor-Owned Utilities

Year	Total Construction	Generation	Transmission	Distribution
1990	22.6	8.8	2.4	9.1
1989	23.1	9.9	2.5	8.7
1988	21.8	9.9	1.9	8.2
1987	25.5	14.4	2.1	7.4
1986	29.3	18.5	1.7	7.2
1985	31.1	21.4	1.8	6.6
1984	33.4	23.9	2.2	5.9
1983	38.8	24.9	2.3	5.0
1982	35.3	25.3	2.2	4.8
1981	30.7	20.9	2.3	4.6
1980	28.3	19.2	2.3	4.5
1979	26.8	18.3	2.1	4.3
1978	24.0	16.1	1.7	3.9
1977	21.3	14.4	1.7	3.4
1976	18.2	11.9	1.8	2.9
1975	16.2	10.1	1.8	3.1
1974	17.2	10.1	2.1	3.6
1973	15.3	8.6	1.9	3.6

IV. Political Economy of Regulation

A. Dominance of the Investor-Owned Model

There has always been, and continues to be, a great variety of organizational forms in the U.S. electric utility industry. Within this variety, however, the investor-owned firm, subject to state regulation, emerged as the dominant model, and remains so today. Unlike most other industrial countries, the U.S. electricity industry was never nationalized. It is not entirely clear why this is the case. Two hypotheses suggest themselves, however; these are (1) geographical diffusion (the "wide-open spaces" theory), and (2) the relative lack of devastating destruction (the "no land wars" theory).

The geographical argument has both a technological and an institutional dimension. A nationalized industry will be operated in some sense as a single system. Whether this means "single area dispatch" or a national grid in some literal sense is unclear. But a nationalized system will have a central locus of decision-making that can be expected to be in the political capital of the nation state. The determination of standards and practices will emanate from such a center, with relatively little input from provincial interests. The U.S. history of localism in political decision-making is not consistent with a national scale model. Political struggles over the balance of power in the federal system are endemic in U.S. history.

Typically, it is national crises which have accelerated the gathering of political power in the national government. Indeed, the economic problems of the 1930s did have this effect to a certain degree in the U.S. The federal role in hydroelectric power development grew to be an important force starting in the 1930s, as indicated earlier. But even these activities had a distinctly regional flavor to them. Where federal agencies were created for power development and marketing, they were dedicated to regional economic development mandates. The municipal preference for federal power helped improve the competitive position of public utilities vis a vis investor-owned firms. But by propping up these small entities, the federal government was curtailing the consolidation of the industry into larger and larger units.

Consolidation was feasible in the investor-owned segment, and it did occur to a considerable degree. Table 7 shows the number of firms operating in certain individual states during the period 1938-1968, as well as national totals.

Table 7. Number of Investor-Owned Firms

State	1938	1948	1958	1968
California	8	7	5	3
Illinois	16	16	9	8
Massachusetts	43	36	25	16
New Jersey	5	7	6	5
New York	22	19	14	8
Ohio	15	13	11	8
Pennsylvania	22	21	18	12
National Total	412	321	265	236

Table 7 shows a moderate amount of consolidation over the time period. Only New Jersey and Michigan are exceptions to this trend. The former because it had reached its current configuration by 1935; the latter because fringe entry by small firms occurred in less populated regions. The more common occurrence is the absorption of small regional firms by larger utilities based in the principal metropolitan areas. In California, both Pacific Gas and Electric and Southern California Edison absorbed regional firms with large service territories but small populations. Consolidated Edison in New York city was formed by the merger of five local firms. Several of the utilities operating in Ohio are part of the American Electric Power system, which is a holding company operating in other states as well.

Given the substantial competitive assistance that the federal government offered to municipal and co-operative systems from the 1930s onward, it is possible that consolidation helped the investor-owned segment maintain its market share by lowering cost. Nonetheless, the average size of U.S. electric utilities is still comparatively small, since merger activity slowed substantially by 1960.

B. Productivity Stagnation and Its Consequences

The U.S. regulatory system functioned smoothly during the post-WWII period as long as productivity increases continued. When these stagnated and began to reverse themselves in the 1970s and early 1980s, the system came under strain. The regulatory response to these conditions was a variety of experiments. We give a brief overview of these experiments, some of which will be examined in more detail below.

The locus of productivity problems in electricity was in new generating capacity. Initially the problem had its origin in the increased stringency of environmental regulation. The Clean Air Act and the requirements of the National Environmental Policy Act raised the cost of new power plants by requiring extensive review of the impact of new facilities and imposing mitigation costs. The effects of these changes were most pronounced in the case of nuclear power. Changes in safety requirements following the Three Mile Island accident of 1979 required considerable extra work on a large number of plants under construction. The high interest rates during this period, declining rates of demand growth, and management inefficiency also had negative impacts on construction costs. When plants entered commercial operation in the early 1980s, their nominal dollar costs were frequently 5 to 10 times higher than original estimates.

Regulatory practice in the U.S. commonly delays the recognition of new plant costs in rates until these plants operate. At the time of commercial operation, their costs are placed into "rate base" and become part of the total cost of service that must be recovered through rate design. A crucial step in this process is the determination that the costs were prudently incurred and that the projects are "used and useful." The experience of nuclear power plant construction elevated these questions considerably compared to their previous treatment. Many state commissions determined that not all costs were prudent. Disallowances in the range of 10-40% became frequent during the 1983-1987 period. The total disallowance has been estimated at $10 billion (ORNL, 1987, 1989). In some cases the rationale for these actions was based on prudence; in some cases it was based on excess capacity. Usually in the latter case, the utility would eventually recover some of the costs as demand increased. In any event, the experience of disallowances (which was not confined entirely to nuclear plants) created strong incentive effects. Utilities that were punished financially had a disincentive for investment. Regulators, disappointed with the performance of firms, developed a more activist stance regarding alternative resource strategies.

One strategy adopted in a number of state jurisdictions regarding baseload power plants was the implementation of performance incentive schemes. In their survey of incentive mechanisms in the U.S. electric utility industry, Joskow and Schmalensee (1986) found that most were addressed to the operation of new large coal and nuclear plants. The productivity of these capital intensive facilities depends considerably on their level of production. The incentive schemes devised by regulatory commissions were intended to encourage a high level of operation through a system of rewards and penalties. The effect of these incentives is doubtful. Berg and Jeong (1991) studied incentive regulation of electric utilities. They construct a predictive model of the regulatory agency's tendency to adopt such mechanisms. The basic predictive variable is a measure of cost inefficiency for the firm as a whole. They find that this variable is a good predictor of the agency's behavior. Unfortunately, they find that firm inefficiency does not decline after these mechanisms are adopted. Presumably such results, if correct, occur because the incentive is limited to only part of the firms' behavior and not all of it.

C. The Search for Alternatives

More substantial discipline can be imposed on the firm through various forms of competition. There has always been a certain amount of interfuel competition, but it is usually limited to certain demand segments. The residential space heating and water heating market has involved competition between heating oil, natural gas, and electricity. Industrial processes are also an area where electricity competes with other fuels. In many precision applications, electricity is winning market share. These forms of competition usually involve pricing strategies that push prices closer to marginal costs. The regulatory rationale for these prices, however, seldom invokes economic efficiency arguments, but instead focuses on the desirability of retaining customers to contribute to system overhead costs.

Yardstick and franchise competition among regulated utilities play even more limited roles. There are cases where utilities compete for customers where franchise boundaries are loose or indistinct. Commonly this competition is based upon price. Similarly, government-owned utilities of various kinds compete with investor-owned firms also by offering lower costs to their customers. The economic performance of government-owned utilities is quite variable. Where they are well-managed and/or endowed with low cost resources, they can offer distinct advantages. In other cases, poor management and inefficiencies have led to their eventual absorption by investor-owned utilities.

By far the greatest competitive pressure comes from bypass, in its various forms, and from private power generation. These two forms of competition have several points of overlap and some distinct differences. The main form of bypass is self-generation by industrial firms. This usually takes advantage of opportunities that are not available to the utility. The two primary sources of efficiency are the use of waste fuels and cogeneration; i.e., useful application of industrial process heat produced jointly with electric power. Bypass also can occur if a customer can get delivery over the transmission network of power produced by someone other than the franchised utility. Transmission service of this kind is generally unavailable for ultimate customers, but can be obtained by publicly-owned utilities. Thus, municipalities may bypass investor-owned firms and get their former supplier to transmit the power supplied by a competing firm.

Frequently, industrial firms that seek the self-generation alternative find it economic to invest in facilities that have substantially greater capacity than the on-site requirements. In this case, the extra capacity is sold to the franchised utility under the PURPA rules. The economic opportunity depends critically on the prices and other terms offered for wholesale power, which are strongly influenced by the regulatory commission. By making the terms attractive, the regulator can encourage alternate, competitive suppliers that will take some of the native supply market away from the franchised utility.

Regulation also can affect the market position of the utility by mandating demand-side policies. These interventions, primarily emphasizing conservation and load management technologies, became increasingly common in the latter half of the 1980s under the general heading of "least-cost utility planning." The basic perception here was that conservation represented the least social cost approach to meeting the demand for electricity services, but that market failures were limiting its role. Therefore, utility regulation should intervene to address this concern (Krause and Eto, 1988).

Demand-side interventions come in a wide variety of forms and with a multiplicity of objectives. Load management is typically a set of activities directed at reducing consumption for relatively brief periods of time when systemwide demand is at or near its peak levels. This can be done using hardware devices aimed at specific end-uses, or more broadly with rate incentives to customers who select their own curtailment procedures. Conservation programs have potentially larger impacts on the utility because they affect a bigger fraction of sales. It is not in the utility's financial interest to pursue conservation activities unless the avoided cost of reduced sales exceeds the lost revenue. Although this may occur near times of peak load (thus making load management attractive), it is less likely for the broad spectrum of conservation opportunities. Thus regulators need to motivate utilities to pursue conservation though incentive mechanisms if these policies are to be pursued.

Evaluating particular utility interventions on the demand-side can be extremely difficult. In some cases, they have been shown to be economic (Train and Ignelzi, 1987), but in other cases the costs of conservation have greatly exceeded the cost of supply (Quigley, 1991, Joskow and Marron, 1993). As the range and scope of these efforts increases and becomes more varied (see Nadel, 1991), it will be more difficult to assess meaningfully the claims made on behalf of these efforts.

V. Appraisal of Economic Performance

Because retail rates deviate from marginal costs, the electricity system in the U.S. is less efficient than it could be given its existing capital stock. Gilbert and Henly (1991) have estimated the welfare losses from inefficient pricing for Northern California. They find that annual losses amount to about 7% of costs for the conditions that they examine. If these results were scaled up to the level of the U.S. industry as a whole then welfare losses would be about $12 billion annually.

It is interesting to compare the magnitude of this efficiency loss to productive inefficiencies in the firm. These can be measured in a variety of ways. One approach would be to focus on excessive employment. It is widely believed that utilities in developing countries use an excessive amount of unproductive labor. Similar assertions have been made about the situation in industrialized countries. As a rough approximation, we can estimate that the amount of employment in the U.S. electricity industry could be reduced by as much as 20% with no decline in service quality. Total employment in the industry is approximately 600,000 (EEI). We estimate that the total wage bill is approximately $30 billion. Therefore, efficiency gains from streamlined labor practices would be about $6 billion annually.

A third area where economic performance might improve is in the efficiency of investment. Experience with competitive bidding for electric generating capacity suggests that cost efficiencies are possible in that segment. Estimates of cost reductions compared to the behavior of regulated firms indicate benefits of 10-15% (Kahn, 1991). For a steady-state capital requirement of about $30 billion per year for generation, the potential efficiencies from competition in the new capacity segment of electricity generation are about $3-4.5 billion annually.

Part 2. Competitive Bidding and Independent Power

I. Introduction

The creation of an unregulated independent power industry in the U.S. began incrementally, and without explicit central policy design, as a result of a number of separate legal, regulatory and economic changes. The major watershed event was the passage of the Public Utilities Regulatory Policies Act (PURPA) of 1978. PURPA created a class of private suppliers, called Qualifying Facilities (QFs) that were exempt from profit regulation and entitled to sell their output to franchised utilities. In some states, the terms of purchase were so attractive that development of QF capacity overwhelmed expectations. In response, utilities and regulators began to seek mechanisms that would ration the supply efficiently. The mechanism which arose to achieve this was competitive bidding for long term power sales contracts. This mechanism has proved to be sufficiently flexible and attractive to both buyers and sellers, that it has been broadened to include a new classes of suppliers; first, Independent Power Producers (IPPs), more recently Exempt Wholesale Generators (EWGs). While these new entrants have not usurped the market for new generation capacity, they are expected to sustain a significant share of the market. In this part we describe the background and development of the private power industry, characterize its current state, and examine the economics of enhanced competition in wholesale generation.

II. Legal and Regulatory History

It is natural to divide this discussion into those issues arising directly from PURPA, and the issues associated with Independent Power Producers (IPPs). IPPs are a class of unregulated private suppliers that lack the special status granted to QFs by PURPA. Under PURPA, a QF is a facility with a electricity production capacity of less than 50 Megawatts, or any electric power facility that uses either renewable fuels or cogeneration, the combined production of useful heat and power in a single process. The distinction between QFs and IPPs reflects an evolution from a federal initiative to encourage entry of alternative sources of electricity to a recognition at both the state and federal levels that non-utility generators are a viable source of electric power. In Section A we concentrate on how the states implemented the PURPA rules. A great deal of experimentation occurred, many aspects of which were not anticipated. When the QF market had eventually developed far beyond the expectations of PURPA's original assumptions, the Federal Energy Regulatory Commission (FERC) re-asserted itself, and the policy dialogue shifted again to the federal level. In Section B we review those issues raised at FERC and the federal level more broadly.

A. PURPA Implementation

The PURPA legislation was designed to set a general framework for QF development, but to delegate implementation of principles to state regulatory commissions. FERC was mandated to write rules that state commissions had to follow in their deliberations. The resulting FERC regulations were broadly permissive, rather than narrowly prescriptive. The two irreducible requirements of the legislation and FERC rules, however, were the obligation placed upon utilities to purchase QF output, and the avoided cost concept as the guide to determining the purchase price. PURPA also defined the class of Qualifying Facilities (QFs) on technological grounds. In this section we review all three issues, obligation to purchase, avoided cost concepts, and QF definition in light of subsequent developments.

A.1. Obligation to Purchase: Contract vs.Tariff

The primary obligation PURPA placed on utilities was the requirement to purchase QF output. In the absence of such an obligation, private suppliers had little or no bargaining power with the utility. Prior to PURPA, some utilities did purchase a small amount of power, principally from industrial self-generators selling excess production, but this was a minor phenomenon. Total industrial generating capacity has been estimated to be less than 3% of all U.S. electricity capacity in 1980 (USOTA, 1983). This includes both self-generation and excess sales. Since most industrial generation went to meet internal demand, the amount sold to utilities was therefore quite small. PURPA required that all utilities create a tariff under which they would purchase from QFs (tariffs were also required for back-up service from the utility and related services). The FERC rules also allowed for long term contracts for purchase between utilities and QFs, but did not require these.

In practice, the difference between tariff and contract turned out to be decisive. Private investors were reluctant to support projects whose revenue was based on revisable tariffs. Because many projects were financed on a "stand-alone" basis, long term pricing certainty was necessary to support the project's credit (Kahn, Ch.6, 1988). In states where regulators were sympathetic to QF development, utilities were encouraged or required to make available long term contracts. These contracts typically had standard language which defined mutual relationships explicitly, or at least substantially narrowed the room for negotiation. The availability of standard contracts frequently made all the difference with regard to development. For example, the staff of the New Jersey Board of Public Utilities found that when tariffs only were offered, the response was minimal. When long term contracts were offered, the response was substantial (NJBPU, 1986).

The need for long term contracts to stimulate investment in private power is probably due to the considerable immobility of capital in this market. The obligation to purchase is limited to the utility serving the region in which the QF is located. Transmission access has been quite limited, so QFs have very little ability to seek other buyers. Wholesale transactions are generally limited to inter-utility exchanges. Therefore, since the utility is a monopsony buyer, and can limit or manipulate the purchase price for QF output, the seller needs a long term contract with fixed prices to limit opportunism.

A.2. Avoided Cost Concepts

PURPA defined the pricing rule in both the long and short run using the notion of avoided cost. The fundamental idea underlying the avoided cost concept was that ratepayers should be indifferent to QF purchases. This meant that any economic rent accruing from QF efficiency would flow to the private producers, not utility ratepayers. State implementation of the avoided cost concept focused on the substantial practical problems of estimating what constituted ratepayer indifference.

The distinction between avoided energy and avoided capacity costs is basic. The former is appropriately measured considering the operations and dispatch of the power system (see, for example, Jabbour, 1986). The latter is essentially a reliability issue; capacity costs are incurred to reduce the probability that shortages will occur. Where utilities had excess capacity, avoided costs were predominantly associated with energy. In cases where utilities had capacity requirements, both terms had to be considered, commonly in a framework that examined a wide range of generation technology options. Utilities and state commissions in practice negotiated estimates of avoided cost. The boundaries of these negotiations could be broad, requiring compromises between precision and ease of estimations.

Gradually, avoided cost concepts began to find their way into other aspects of utility planning and regulatory discourse. Avoided cost projections tended to become ubiquitous standards of the value of all resources. Hence, they were used to evaluate whether demand-side programs were cost-effective, or even whether new utility plant was "used and useful." The whole process had its cumbersome and arbitrary side, because avoided cost is itself very difficult in practice to estimate. Over time, however, greater understanding of its components began to emerge.

Seen more broadly, the avoided cost dialogue is part of the "cost unbundling process" in which the underlying cost structure of the firm gets studied with greater and greater sophistication and depth. The "cost unbundling" trend is a common phenomenon in all regulated industries under competitive pressure (Bailey, 1986). What is different in this case is that a competitive fringe of firms audits the costs of the incumbent by litigating these costs in regulatory proceedings. The advantage of this arrangement is that the regulatory process can compel disclosure that otherwise would not occur. The disadvantage is that the competitors are seeking economic rents in their use of the regulatory process, so their auditing function is not necessarily unbiased.

A.3. QF Definitions: Are PURPA Machines Bad or Good?

PURPA created a class of favored producers, defined in large part on technology characteristics. The most controversial aspect of the technology definitions is the standard for cogeneration. In regions where private power production was encouraged, the value of electricity could greatly exceed the value of thermal energy, even in the best applications. Consequently, developers began pursuing projects where the thermal applications were increasingly peripheral to the power production. The classic case of this kind is a simple greenhouse attached to a large scale power plant. There is no real need for the thermal sink to be an actually profitable business. Its value really lies in the ease of designating a project as a QF. This kind of QF development became called a "PURPA machine," indicating that what was actually being produced was an exemption from regulation. In the 1988 Virginia Power competitive solicitation, three out of 17 winning projects listed "undeveloped greenhouse" as their thermal application.

A policy debate emerged over the PURPA machine phenomenon. Critics of PURPA, largely investor-owned utilities, viewed PURPA machines as an indicator that QF development had become inefficient. The fuel efficiencies claimed for cogeneration were not really representing productive economic activity. Proponents of increased competition in electricity generation interpreted the phenomenon in an entirely different light. They claimed that PURPA experience proved that private production was feasible and efficient for reasons entirely beyond the fuel efficiencies of cogeneration. The profit orientation of QF developers resulted in a more efficient set of investment and operating practices compared to the performance of regulated utilities. The thermal application requirement needed to achieve QF designation for cogenerators was indeed something of a sham. But what was needed was not stricter requirements, but more opportunity for private production.

B. The Emergence of Federal Competition Policy

The PURPA machine debate became part of a much broader dialogue on the role of competition in electricity generation. This dialogue emerged in 1988 when FERC issued three Notices of Proposed Rulemaking (NOPRs) that addressed the commission's perceptions of appropriate reforms of the PURPA framework. Although these did not result in any explicit rule changes, they signalled a new interest in competitive mechanisms.

FERC subsequently approved a number of wholesale transactions involving non-QF suppliers based on market prices. The precise characterization of when a transaction qualifies for such pricing was subject to case law definition (Tenenbaum and Henderson, 1991). FERC activity in merger cases also showed a strong concern for competitive effects. As a condition for approving the merger of Pacific Power and Light with Utah Power and Light, specific transmission access conditions were required for third-party sellers.

In 1992, the policy agenda shifted to the legislative arena. The Energy Policy Act created a new class of private producers as part of a change in federal regulation under the Securities Exchange Commission. The transmission access questions were also addressed in this legislation, but in ways that will take time to assess.

III. Development of the Private Power Industry

The legal and regulatory framework described above only sketches the broadest outline of the private power market. There was substantial regional variation in policy and resource opportunities that contributed to quite different levels and styles of development. In this section we survey market developments to highlight the important trends and issues that will shape the future of this industry. We begin with a brief historical sketch. Section A examines standard offer contracts. Section B describes the role played by tax policy in encouraging certain technologies. Section C gives an overview of the implementation issues associated with the spread of competitive bidding. More general questions indicative of future developments are then raised. In Section D we discuss technological innovation by private developers. This has important implications for the long run viability of competition.

A. Standard Offer Contracts

Initial responses to PURPA were limited. Few projects developed because there was great uncertainty about the terms for power purchases. For this reason, QFs urged regulatory commissions to standardize the form of agreements between utilities and private suppliers and to require long term purchase contracts.

The California standard offers proved to be lucrative for QFs and a very large number were signed. The phenomenon became referred to as a "gold rush," since the perception spread that prices were substantially in excess of value. Of course, the more contracts signed, the more out of line with value they became, since increasing QF supply would reduce marginal or avoided cost. The California regulators were forced to suspend the most lucrative of these offers less than two years after they were first announced.

B. The Role of Tax Policy

The National Energy Act of 1978, contemporaneous with PURPA, authorized 15% investment tax credits for renewable energy technologies. Subsequent changes in the general tax code designed to encourage capital investment by increasing depreciation allowances also benefitted energy projects. Some states, notably California, offered further tax incentives for particular technologies by allowing state income tax credits. The combined effect of these measures was a very strong incentive for the development of private power projects. The technology which benefitted most was wind turbine generation, particularly in California. From essentially no capacity of this type in 1980, California witnessed the installation of 1436 MW of capacity by 1987, and the production of 1700 GWh of electricity in that year.

Cox, Blumstein and Gilbert (1991) give a detailed review of the wind turbine industry experience in California during the 1980s. Large scale development prompted by tax incentives and attractive standard offer contracts resulted in cost reductions and performance improvements over time, however the cost of wind energy throughout the decade was still quite high compared to conventional alternatives.

In 1986, federal tax law changed significantly. Marginal tax rates were lowered, depreciation allowances became less generous and tax credits of all kinds disappeared. These changes radically altered the private costs of all energy projects. Returns on investment dropped significantly for renewable energy projects; the decline was noticeable but not as substantial for cogeneration projects (Kahn and Goldman, 1987). The resulting effect on capital formation was significant. QF projects based on renewable energy technology contracted significantly. Cogeneration projects, however, continued to expand. The market developments confirmed academic estimates of the relative economic viability of the QF technologies.

Under Title XII of the 1992 Energy Policy Act, the U.S. government will pay producers of electricity from renewable resources a "production incentive payment" of 1.5¢/kWh. This subsidy coupled with technological improvement is apt to rekindle the market for renewable electric generation.

C. Competitive Bidding Practices

Competitive bidding for long term contracts, first introduced in Maine, Massachusetts and Virginia, emerged as a successor to the "first-come/first served" rationing mechanism associated with standard offers. The bid evaluation process, however, is complicated by the multi-attribute nature of electricity supply. Proposed projects differ by their fuel type, level of development, location in the transmission network, environmental effects, and operational flexibility. A bid evaluation procedure should take all these factors into account along with price. Since it is difficult to compare all of these attributes with a common metric, it is inevitable that qualitative judgment will play a role in the evaluation process.

Competitive bidding brought product differentiation to the independent power market. Under early PURPA implementation regimes, the obligation to purchase QF power meant that all such production was "must take" in nature. A number of factors, however, led to increasing operational problems on power systems, especially during "off-peak" or low load periods. The fundamental problems was that there was an excess of inflexible generation at these times, relative to demand (Le, et.al, 1991). Thus the demand for more flexible operation became great, and utilities began to emphasize this need in their requests for bids.

There are a variety of ways that utilities structured their requests for bids and the corresponding evaluation system to emphasize operational flexibility. At one extreme, the utility can simply view competitive bidding as equivalent to its own capacity expansion procedure. Bidding will elicit the prices of different generation types, and the standard planning procedures will be used to select the least cost mix. Therefore substantial discretion must be delegated by the regulator to the utility to make value comparisons across among different generation types and to incorporate non-price factors into the analysis. Virginia Power (1988) is the best representative of this approach. The analytic problems posed by this approach are discussed in Kahn, et.al. (1991). The opposite approach involves solicitations for just one type of capacity. This approach has so far usually been applied to peaking technology. The largest solicitation of this kind was Public Service of Indiana (1989).

C.1. Risk Allocation in Contracts

A major motivation for independent power production is to transfer risks previously borne by the regulated firm to private producers, who may be able to handle them more efficiently. This subject is surveyed by Kahn (1991). Although contracts can be structured to allocate risks in different ways, a pattern of risk-bearing has emerged in contract solicitations. Conceptually, we may separate the risks of power production into four categories: (1) construction cost risk, (2) fuel price risk, (3) demand risk, and (4) performance risk. The first of these, construction cost risk, is typically passed from the utility to the private supplier. The transfer of this risk is achieved by fixing a capacity payment formula in the contract at the time of project selection. Any cost-overruns facing the private producer will not be recoverable from the utility. This arrangement is quite different from the standard relations between the utility and the regulator. Utilities are allowed to appeal for recovery of unanticipated costs, although this is subject to litigation, and the outcome is not always very favorable for the firm.

Fuel price risks are not typically borne by the private producers. The variable cost of production is usually set in the contract for the first year of operation. This variable cost consists of a fuel price, a conversion efficiency and perhaps a variable operations and maintenance cost. Over the term of the contract, the private producer is responsible for maintaining the conversion efficiency, but the other components are indexed to some external cost measure for future years. This arrangement passes most macro-economic risks associated with fuel prices through to utility ratepayers. It differs only slightly from the fuel adjustment mechanisms used by the regulated firm to achieve the same risk transfer.

Demand risks involve the need for power. When the regulated firm invests in new capacity it is subject to this risk. Upon completion of new capacity construction projects, the regulator may deem the investment "excess capacity," and prevent recovery of some or even all of its costs. Private power contracts do not typically transfer the demand risk to the private supplier. The contracts commit the utility to purchase power under the price and supply terms specified. These terms may include limitations on purchase, but they are fully agreed upon by the buyer and seller, and not typically subject to regulatory review. By limiting the demand risk facing the private supplier, his cost of capital is lowered, but a risk premium is transferred to the utility (Perl and Luftig, 1990).

Performance risks are borne primarily by the private suppliers. The contracts specify availability targets that must be met and penalties for failure to meet them. Periodic capacity tests, which verify the supplier's ability to produce to contract levels, are also a standard requirements. The performance requirements in independent power contracts are in some ways parallel to the incentive mechanisms adopted by many state commissions regarding new baseload utility power plants (Joskow and Schmalensee, 1986; Brown, Einhorn, and Vogelsang, 1989). Although the incentive mechanisms are supposed to increase the productive efficiency of utilities, evidence to date does not suggest that they work particularly well (Berg and Jeong, 1991). Private producers have considerably less opportunity for organizational slack than regulated firms. Therefore one can expect somewhat better results from performance requirements in their case. Experience is still too limited to conclude with assurance that this will be the case.

C.2. Price Trends

One of the principal motivations for competitive bidding is to lower the cost of power. Although evidence on this is fragmentary, there is reason to believe that prices are coming down. Table 8, from Kahn (1991), shows for a small sample of projects that prices are getting lower over time. These data are not without ambiguity, and require some discussion. Further, there are a variety of non-price terms which affect the overall value of the projects. The non-price terms involve either operational flexibilities or contractual performance requirements. Broadly speaking, the more recent projects offer the utilities more operating freedom and stricter contract terms. A brief explanation of the Table 8 data should make clear the extent to which clear conclusions are possible.

To make price comparisons, it is necessary to select projects selling more or less the same service. Table 8 considers projects that are intended to provide baseload operation. Only one of these is a PURPA "must-take" supplier, that is the Kern River Cogeneration Company (KRCC) project. KRCC is priced on a basis closely modelled on the California standard offer contracts. It uses the "heat rate" pricing formula for variable costs described in Section C.1 above, where the contract heat rate of 9300 Btu/kWh multiplies a natural gas price that includes pipeline demand charges as well as gas commodity costs. The details of natural gas pricing are important for the comparisons in Table 8, because projects involve different approaches to gas pipeline costs.

Hopewell is the project priced most nearly like KRCC; its variable pricing is virtually identical. Operationally, however, Hopewell offers substantially more flexibility than KRCC. KRCC offers only very limited curtailment options to the utility; that is the PURPA obligation to purchase output can only be neglected for about 1000 hours per year. Hopewell is fully dispatchable by the utility. It can be curtailed to about 25% of capacity if desired, or turned off completely. These dispatch decisions are constrained only by engineering limits. In addition to the operating flexibility, Hopewell's capacity price is about 15% less than KRCC in nominal dollars. Since it came into operation five years later, the real cost difference is even greater.

Table 8. Price Trends in the Private Power Market

Baseload Gas	Start Date	Fixed Payment	Variable Payment
KRCC	1985	$143/kW-yr	9300 Btu/kWh * Gas Price with Demand Charges
Doswell	1991	$115/kW-yr[a]	8470 Btu/kWh * Gas Commodity Costs
Hopewell	1990	$121/kW-yr	9300 Btu/kWh * Gas Price with Demand Charges
Turbo	1991	$128/kW-yr	8846 Btu/kWh[b] * Gas Commodity Costs
Baseload Coal			
AES Shady Point	1993	$405/kW-yr[c]	
Vista/Paulsboro	1994	$378/kW-yr	
Indiantown	1996	$361/kW-yr	

[a] plus fixed pipeline demand charges
[b] adjusted for distillate oil premium during four winter months
[c] pricing during 1991 and 1992 estimated at about $300/kW-yr

Both Doswell and Turbo are structured differently. In these cases the contract heat rate used for variable cost pricing multiplies gas commodity costs only. Doswell treats gas pipeline demand charges as a fixed cost. These are in addition to the $115/kW-yr levelized capacity payment listed in Table 8. Including the pipeline demand charges, Doswell's total fixed costs are roughly comparable to KRCC in nominal dollars, but lower in real terms due to the six year difference in starting date. Both the heat rate and the fuel price terms in Doswell variable costs are lower than KRCC. Doswell offers less operating flexibility than Hopewell, but more than KRCC. Turbo is a dual fuel project which uses distillate oil during the peak winter gas demand season, and gas otherwise. The heat rate listed in Table 8 is an estimate of the weighted average effect of premium distillate oil prices.

The coal-fired projects present none of these complexities. The only price comparison offered involves fixed capacity costs, because fuel prices are largely determined by regional factors. The AES Shady Point project is based on avoided cost prices. The capacity payments starting in 1993 are estimated to be $405/kW-yr on a levelized basis. The Vista/Paulsboro projects were winners of the Jersey Central Power and Light competitive solicitation in 1989. The Indiantown project was the result of private negotiations between the developer and Florida Power and Light, which were concluded in 1990. Both of these more recent projects have lower prices in nominal terms and are located in higher cost regions. In addition, the performance requirements in the power purchase contracts are more stringent in these cases than in AES Shady Point.

None of this data is absolutely conclusive. The number of cases reviewed is small. The productivity gains reflected in Table 8 may be generic to the industry, rather than due to the superior performance of the private producers. Even if this latter hypothesis is correct, however, some of the stimulus for these gains can be attributed to competitive pressure.

D. Technology Innovation

Private power production offers incentives for technical innovation that are absent from rate of return regulation. Under the fixed price formulas contained in private power contracts, any cost-reducing technology adopted by the supplier adds to profit. The private producer also takes the risk that the innovation adopted will not perform as expected. Regulated firms, on the other hand, must pass all production economies realized through innovation through to ratepayers. They do not contribute to profit. When the outcome of adopting new technology is not favorable, the regulated firm may also be denied cost recovery by the regulator (Zimmerman, 1988). These incentives may combine to bias the regulated firm away from risky new technology, while leaving the private firm neutral.

There was a significant record of new technology adoption by the private power industry during the 1980s. The first steam-injected gas turbine (STIG) was installed by a California paper mill subject to stringent air pollution control requirements (Kolp and Moeller, 1988). The adoption of circulating fluidized bed (CFB) coal combustion was also substantially more widespread in the private power section than among regulated or government-owned utilities (Grahame, 1990). In the area of renewable energy, the solar thermal technology of Luz International was commercialized through private power contracts.

While none of this evidence conclusively proves that more innovation will occur under private power than under a regime of regulation, it is clearly suggestive.

Part 3. Alternative Regulatory Futures

I. Introduction

In this part we outline the generic options for regulatory policy in light of the political economy in which the electric power sector operates. We distinguish three principal alternative regulatory futures, each of which has a number of variations on the primary theme. The principal axis along which we differentiate is the role and scope of competition.

The *first* option we explore amounts to suppressing the competitive segment in generation and reverting to the traditional structure of vertically integrated franchise monopolies with rate of return regulation. We sketch the diagnosis on which this option is based and assess the forces that are likely to oppose this solution. The *second* option is a continuation of the current regulatory situation which has promoted more competition in generation, but with only minor changes in the vertically integrated utility structure. There are two principal problems facing this alternative. First, the regulator must have a strategy to "manage" the coexistence of competitive suppliers with the traditional regulated firm. A major part of this will involve questions of incremental market share for new capacity and management of the transmission network. The *third* option is a movement toward a more radical restructuring model represented by the privatized British electricity system. The U.S. policy economy poses substantial barriers to such a movement, but it is not impossible, and may represent a potentially more stable configuration than the managed competition alternatives.

II. Option 1: Putting the Competition Genie Back in the Bottle

The competitive segment of the generation market is not viewed favorably by all participants in the U.S. electricity sector. The "unbundling" of generation from transmission and distribution, which has been the main channel for new entry into the industry, is not without cost. Extracting the private information about transmission costs can be very difficult, and may not be worthwhile unless the benefits of competition are sufficiently great (Gilbert and Riordan, 1992; Baldick and Kahn, (to appear)). Critics of deregulated generation assert that the apparent success of private producers was due to special regulatory treatment rather than economic superiority. In many regions of the U.S., the emergence of the private power industry is closely tied with the productivity problems of the vertically integrated firms. If these problems are viewed as transitory and solvable, then the basic traditional structure of franchised monopoly may be salvaged and revived.

The policy focus of this discussion is the role of prudence reviews. The proponents of a revitalized form of vertical integration argue that "rolling review" of utility construction projects can provide both flexibility to changing circumstances and regulatory oversight. The basic idea is that utility construction projects are reviewed periodically during their gestation. Once a certain stage of construction has been approved, there will be no further retrospective review. In this version of the regulatory compact, the firm recovers all costs that have been declared prudent, but may cancel projects deemed uneconomic upon agreement with the regulator (Steinmeier, 1991).

It is hard to imagine such a system working easily. While it would certainly protect the financial interests of the utility, it may not serve the consumer interest. The decision to declare a project uneconomic after substantial sums have been invested is politically difficult. The uncertainties surrounding any such decision are apt to produce a reluctant inertia. Ultimately, there is no competitive test for what defines an economic project.

The rolling review approach to the preservation of vertical integration as a regulated monopoly, also runs into stubborn political and economic realities that threaten its viability. The private power segment has shown an ability to reduce prices to consumers and to promote technological innovation. This industry is also well represented politically, and so is capable of defending its market so long as its economic claims are sustainable. Moreover, the Energy Policy Act of 1992 mandates more open access by independent power producers to transmission markets, and thus essentially bars a return to a less competitive era.

The importance of Option 1 lies in the vertical integration issue. The stark contrast drawn between complete vertical integration and its total absence is considerably overdrawn by proponents of this option. Nonetheless, there are very real questions about the role of utilities in the generation market where a competitive segment also exists. The next two options address these questions more positively.

III. Option 2: "Managed" Competition

The U.S. electricity system is moving *de facto* toward a mixed system where wholesale competition is balanced by some unclearly defined role for the traditional firm. The principal question is how the regulator will handle two structural issues: the market share in generation for the IOUs and how regulation of the distribution segment will be structured.

A. Allocation of Market Share in the Generation Segment

Competitive bidding for long term contracts is the fundamental mechanism through which independent producers are entering the wholesale electricity business. The main regulatory policy question is whether this will result in a slow liquidation of the IOU role in generation. Regulatory policy amounts to deciding if and how IOUs continue to invest in generation. There are two basic alternatives: (1) explicit allocation on a case by case basis, or (2) bidding rules that allow IOU participation in the competitive process. Each of the alternatives for preserving an IOU share in the market for new generation presents its problems.

Explicit allocation may be arbitrary and subject to political manipulation. The case for it depends upon the utility having some unique asset or capability that is unavailable or more costly if acquired from independent producers. The best case of this kind involves the re-powering of old powerplants. There is a substantial stock of aging facilities in the industry's capital stock. These plants frequently have desirable infrastructure features, including access to fuel delivery and favorable location in the transmission network. The incremental costs of adding new generation at these sites can be low compared to construction at new sites.

The case against explicit allocation is a case in favor of a bidding regime in which the utility offers projects that compete with those proposed by private developers. The problem with such a bidding arrangement is that it introduces potential biases in selection criteria. Electricity may be a fairly homogeneous product at the end-use, but power projects are quite differentiated in their features. A bid evaluation system must weigh these features against one another. The greater knowledge of value possessed by the firm makes it difficult for the regulator to know whether the bid evaluation criteria have been slanted to favor the utility project. Whatever might be gained potentially by including utility projects within the universe of bidders can be easily lost by distortion of the evaluation criteria.

For large geographically diverse utilities such as Pacific Gas and Electric Company, Southern California Edison Company and American Electric Power the problems facing private suppliers are limited to negotiating only with the monopsony buyer over the terms for interconnecting with the utility transmission network. Even in this case, problems can arise when system reinforcements are necessary. Given the scale economies that are ubiquitous in transmission capacity, a reinforcement investment will typically be larger than the demands associated with individual project interconnection requirements. In this setting, conflicts over cost allocation are likely. Requiring utilities to make binding estimates of transmission interconnection costs before bidding takes place, as proposed by Pacific Gas and Electric (Shirmohammadi, et.al., 1991), may limit opportunistic bargaining over cost allocation. However, this would not solve the problem that information about utility interconnection and transmission costs are not widely known and that faced with this limited information utilities may earn excessive profits and regulators may cause the industry to move in directions that are not efficient (Gilbert and Riordan, 1992).

The basic regulatory problem in the wholesale segment is that the utility is competing with private suppliers, yet still must act as the agent for consumer interest. These two goals can come into conflict. Frequently the locus of these conflicts lies in management of the transmission system. Monopoly control of transmission can be used to put independent producers at a competitive disadvantage. Access conditions for these producers that are too liberal, however, may harm the distribution system customers by inducing inefficient dispatch. Once again, the regulator must try to manage this conflict in the face of very little information.

B. Distribution System Regulation

The regulatory problems in the retail distribution segment also involve questions of multiple goals. Distribution of electricity is generally assumed to be a natural monopoly and subject to franchise regulation. This raises important issues as to efficiency in the pricing and marketing of electricity, demand-side-management, and investment in the distribution grid. The recent trend toward the promotion of utility DSM programs arises out of a perception that end-use efficiency is a desirable social goal that is under-provided by normal market forces. At the same time, the distribution segment of the business is not subject to much competitive pressure, so may become inefficient. The ability of regulators to encourage efficiency and promote social objectives (e.g.DSM) will be the central challenge of any future regulatory scheme. There are three generic alternatives: (1) traditional rate-of-return regulation, (2) rate of return regulation supplemented with targeted incentives, and (3) some form of comprehensive incentive regulation, such as yardstick mechanisms or price caps. We briefly discuss these alternatives.

B.1. Traditional Rate-of-Return Regulation

The "business as usual" approach to regulation of the distribution segment assumes that there are no serious efficiency problems, nor any social goal agenda such as DSM. If the regulator does perceive such problems and goals, then the traditional approach is unlikely to be very effective.

One can already observe a shift in the investment behavior of investor-owned utilities in response to their declining market share in generation. Table 6 in Part 1 shows a rapid growth in distribution segment investment. While this may be the result of long delayed real needs in that segment, it is also possible that it is just Averch-Johnson type behavior in a protected market.

B.2. Regulation Supplemented with Targeted Incentives

More recent trends in distribution system regulation involve targeted incentives. The principal arena in which this is occurring involves conservation and other DSM activities (Gilbert and Stoft, 1992). If the utility is being forced out of the generation business, and must purchase capacity from independent suppliers, there should be some incentives for efficiency in this activity. There has been discussion of this question, but virtually no concrete activity along these lines.

The main practical issues facing the targeted incentives approach are calibration of the appropriate incentive levels and finding reasonable measures of performance. While it is easy to produce agreement that incentives are useful, it is much harder to find an amount of money that is adequate to induce desirable behavior, but not excessive. Similarly, the measurement of desirable performance can pose challenges. When are good outcomes due to luck or clever manipulation of the incentive scheme, rather than to efficient behavior?

If incentive mechanisms spread over a wide range of utility activity, they may begin to interact with one another. Even if that does not occur, there will still be questions of balance among the various mechanisms. It is questions such as this which motivate a broader approach to incentives, where behavioral targets are replaced by comprehensive measures of performance.

B.3. Comprehensive Incentive Regulation

The logical extension of targeted incentives is a regime based on a comprehensive incentive mechanism. The price cap approach is used widely in Britain to regulate price in the natural gas, telecommunications, water and electricity industries. Price cap regulation uses an external price index adjusted by exogenous estimates reflecting anticipated changes in productivity and other factors (Littlechild and Beesley, 1989).

Applying a price cap approach to electric utilities would fail to account for conservation and DSM activities. These can often raise the price of utility service, while lowering total social costs. Therefore an alternative approach to comprehensive incentive regulation is necessary if DSM is to be incorporated into the mechanism. Suggestions along this line have been made, but as yet this approach has not been implemented.

IV. Option 3: "Radical" Restructuring: British Model Applied in the Piecemeal American Fashion

The privatization of the British electric power system implemented radical changes in regulatory policy. The British system is almost completely vertically de-integrated. Wholesale generators sell to the grid at prices that are determined in a national spot market. Regional electric distribution companies purchase their power requirements from the grid, also at spot prices. Thus all transactions take place through the grid at market-determined prices, although nearly all buyers and sellers hedge these prices by engaging in fixed-price long term contracts.

Forming a centralized transmission/dispatch pooling entity as in the UK would require the aggregation of many systems into a much larger regional entity. It would be plausible to expect that a voluntary association led by large firms or government entities would be the starting point for such developments. Thus the marriage of the transmission assets of Southern California Edison, Bonneville Power Administration and Pacificorp, for example, would be necessary for the creation of a meaningful Pacific Coast Pool. Collecting the individually small transmission assets of a few scattered entities would not create a marketplace for wholesale electric power.

Existing capacity would be transferred from rate-of-return regulation to competitive status. In the absence of large efficiency gains made possible from the transfer, the likely consequences are either that shareholders would be forced to take a loss or that distribution customers would end up paying higher prices for power from assets that they used to own. The former outcome would be resisted by utility management and the latter by regulators. Given the incentives faced by both shareholders and ratepayers, it is reasonable to expect that firms will seek to move assets out of the regulated domain as much for loss minimization as for expectations of realizing large profits.

The re-structuring of the British system was the result of an executive order and was imposed over an extremely short period of time by American regulatory standards. In the U.S., firmly embedded private property rights and a political tradition that encourages stable regulatory policies essentially prohibits the "bang-bang" restructuring approach implemented in England. If major re-structuring were to be achieved in the U.S., it would have to be approximated through slow and partial steps and it would apply incompletely. The highly fragmented industry structure in the U.S. makes full scale rapid change virtually impossible.

V. Transmission -- The Strategic Asset

Private power production will probably remain a significant feature of the generation mix. There is considerable uncertainty, however, over how large a share it may sustain. In a study conducted for the Electric Power Research Institute (EPRI) projections of the market share for private producers in the next decade range from about 30% to 45% (RDC, 1990). Representatives of the private power industry typically forecast a larger share. Much will depend upon the regulatory climate at both the state and federal levels, particularly with regard to the conditions of transmission access. For example, some potential sellers in the 1988 Virginia Power RFP were forced to drop their projects, even after their preliminary selection by the utility, due to lack of transmission from their West Virginia sites.

The alternative regulatory futures characterized above are chiefly distinguished by the extent to which vertical integration remains a feature of the U.S. electricity system, which in turn depends on regulatory policy with respect to the ownership of and access to transmission. Although transmission represents typically only about 10% of the delivered cost of electricity, it is a strategic asset. Wholesale trade occurs through the transmission network. More importantly, transmission access is the key to asset mobility for new generation capacity. The long-term contractual mechanism characteristic of private power development is a product of the limited transmission access regime in which these projects arise. If private producers had better access to the transmission system, and could potentially sell to many customers, perhaps they could attract capital without the necessity of long term contracts.

The principal area for feasible structural change is the wholesale market. The Energy Policy Act of 1992 has opened the door to significant change in wholesale competition by greatly extending the powers of the Federal Energy Commission to mandate transmission access. Prior to this Act, the FERC was prevented from mandating transmission access that interfered with existing competitive relationships. As transmission access is a defining characteristic of wholesale competition, the FERC's power to interfere with state regulation by ordering access was severely constrained. The National Energy Policy Act of 1992 gives the Federal Energy Regulatory Commission the authority to mandate transmission access if

(1) voluntary negotiations have been conducted by the requesting entity and transmission owner for 60 days;
(2) the order would be in the public interest;
(3) reliability of all utility systems affected by the order would be maintained;
(4) third-party wheeling is not subsidized by utility's existing customers.

If the FERC has the objective of promoting wholesale transmission access, it appears that it will now have broad power to do so. The provision against third-party wheeling is likely to limit the FERC's ability to promote competition at the retail level. There is substantial controversy in the U.S. over the issue of competition for end-use customers. Although some erosion of the franchised monopoly in distribution is likely to occur, for the most part there is a resistance to introducing retail competition on a wide scale, as is scheduled to occur in the British electric power market. For these reasons, the scenarios discussed below presume that expanded transmission access will be necessary for wholesale, but not necessarily retail, transactions.

A. Alternative Transmission Proposals

In this section we outline four generic approaches to the organization of transmission transactions. These represent a range from current practices to reform proposals sponsored by government agencies or academics. We match each proposal against the three alternative regulatory futures sketched previously. Not every proposal fits coherently with each of these futures. Finally, we rate these proposals against several threshold conditions that each should satisfy and against certain barriers to implementation.

A.1. Business As Usual

The historic form of transmission access in the U.S. has been to allow the owners of transmission facilities to decide upon terms and conditions without regulatory interference. This policy has not resulted in much third party access to transmission. There has been, however, a fair amount of joint ownership of facilities. Because economies of scale are substantial in transmission capacity, projects built in the past thirty years have had an increasing amount of shared ownership. The pattern of shared ownership in new generating stations has also facilitated sharing in transmission.

In some cases, the voluntary approach has resulted in a reasonable level of trade, at least among franchised utilities. This occurs where many potential participants all have access to a particularly well-situated central location. Once such "marketplace" is the Palo Verde switchyard adjacent to a large nuclear facility in central Arizona. Here buyers (primarily located in Southern California) transact with sellers (from Colorado, Utah, New Mexico and Arizona), primarily for non-firm energy sales at prices that are close to production costs. Such markets are relatively rare, in part because of the widespread presence of reciprocal voluntary arrangements described below.

The system of private ownership gives strong incentives for efficient transactions because utilities are in a position to appropriate benefits. The main exception to this is the "loop flow" externality problem. The electrical properties of the transmission network may result in unintended impacts affecting third parties who are not involved in particular exchanges. This externality is difficult to price, and interferes with arranging transactions. Loop flow also interferes with incentives for investment in new transmission facilities under a system of private ownership, as investment may have uncompensated negative or positive impacts on other parties.

In principle, the "Business As Usual" policy might apply in either Option 1 or 2, since it does not depend upon the utility's share of generation. In practice, however, it is questionable whether this policy can be maintained any longer in the U.S. industry. The Energy Policy Act of 1992 contains provisions that require utilities to provide transmission services to third parties. The new law supersedes previous limitations on regulatory authority that restricted such services if they would have interfered with existing competitive arrangements. Thus, we must conclude that "Business as Usual" in transmission services is no longer feasible for any of the regulatory options.

It is possible that the access provisions of the Energy Policy Act could be eased in geographical regions where the underlying competitive conditions in wholesale markets are quite strong. In these situations a loose form of voluntary access may be sufficient to satisfy the requirements of the new legislation. In most cases, however, voluntary cooperation will need more explicit mechanisms, such as those discussed below.

A.2. Regional Transmission Groups - Reciprocal Voluntary Arrangements

There is a long tradition of reciprocal voluntary transmission arrangements in segments of the U.S. electricity industry. In its most elaborated form, these arrangements underlie the fully integrated power pools that operate principally in the Northeastern region. For a pooling arrangement to work, the members must be able to exchange power freely over the combined network of transmission facilities. Where the pool does central dispatch of the combined generation resources, fully reciprocal use of the combined transmission network occurs.

There are looser pooling arrangements which do not involve central dispatch. In these, some form of reciprocal transmission arrangement is also necessary, but the mutual commitment is less than in the fully integrated case. "Loose" pools commonly operate a kind of brokerage service, where parties post willingness-to-buy and willingness-to-sell offers, but transactions occur through bilateral arrangement. Power pooling institutions in the United States are surveyed in FERC (1981).

The limiting cases of reciprocity are bilateral agreements to exchange transmission services and emergency support involving commitments among many participants in a transmission network. In the latter case, the agreements are only for extraordinary circumstances where reliability is involved. Such arrangements are nearly ubiquitous. Typically the prices charged for emergency support are higher than the prices charged for routine firm and non-firm transmission services.

In principle, reciprocal voluntary arrangements might operate in either Option #1 or #2. The requirements of the Energy Policy Act for offering transmission service might be accommodated within the framework of regional transmission groups (RTGs) which provide for reciprocal arrangements. These arrangements would be voluntary, although it is likely that they would be constrained by a constitution governing the policies of the group. There is considerable uncertainty about how and under what conditions concerning access to facilities such accommodation might or might not be achieved.

One proposal would be for a RTG to develop a cost approach for transmission access that would be based on the avoided-cost principles that govern prices for qualifying facilities. This would require the following elements.

(i) A transmission resource plan (TRP)

The correct cost for transmission access is the incremental cost that a user imposes on a system. This requires an assessment of the impact that a user's demand for access would have on the current cost-minimizing plan for constructing and maintaining adequate transmission capacity to meet the needs of its members. This, in turn, requires the development of a resource plan that is accepted by the RTG members.

(ii) A cost model for the TRP

The preferred TRP would depend on the needs of the Group members, and on the costs of satisfying those needs. This requires the development of a transmission costing model. Such a model would compute the total present-value cost of building and maintaining a desired transmission configuration. Given the economies of scale and interdependencies of transmission costs, it is unlikely that an algorithm could be devised that would choose the optimal plan for the members' needs. Instead, several scenarios would have to be specified and the RTG would have to narrow the search done to those plans that are most cost-effective. Finding the optimal scenario would be an iterative process. Iteration would be necessary to investigate the cost consequences of different plans. An additional complication is that users demands for transmission services depend on their costs. Therefore, the optimal resource plan would have to be an iterated process so that demands are consistent with the cost of the resources that are made available.

(iii) The incremental cost of additional demand for transmission services

If a transmission system has adequate capacity to meet all demand in the foreseeable future, the *economic* cost of transmission is only the cost of line losses and other operating costs that are directly attributable to a user's demands. If the system does not have adequate capacity, the economic cost of transmission includes the present-value of additional investment that must be incurred in order to provide the service. This is the same principle that governs the determination of avoided generation costs. The avoided energy cost is the utility's marginal operating cost. The avoided energy cost is the present-value of the additional investment that the utility would avoid if it had another unit of capacity on the system. The latter depends not only on the cost of capacity, but also on the timing of the investments that would be required to maintain adequate system reliability.

In order to estimate a transmission user's capacity cost, it would be necessary to evaluate the change that the user's demand imposes on the present-value cost of meeting all users' transmission needs. Although the principle is identical to the principle of avoided generation capacity costs, this is a more complicated calculation because the cost is likely to depend on the size and the location of the transmission user's demands. Qualitatively, if $\boldsymbol{T}$ is a vector of all the transmission services that are anticipated in the RTG's optimal resource plan, and if t_{ij} is transmission demand of an individual user, the capacity cost of the transmission service is

$$c(t_{ij}) = C(\boldsymbol{T} + t_{ij}) - C(\boldsymbol{T}),$$

where C(.) is the cost of the optimal resource plan corresponding to the desired services.

(iv) Allocating fixed costs

The above discussion focuses on allocating costs that are incremental to the use of transmission services. Any realistic transmission proposal would have to deal with allocating the fixed costs of transmission as well -- costs that are not sensitive to demand. An RTG could have wide latitude to allocate these costs among its members. There could be a cost for joining the group, a fixed charge for each transmission service (postage stamp pricing), or non-linear charges. These charges are not determined with the objective of allocating scarce transmission resources to their highest-value uses, but rather to spread the fixed costs of the network.

The RTG could use a variety of measures to allocate capacity in the short-run. One possibility is the use of node pricing, as above. Another would be to use the avoided cost-based prices, and to rely on administrative measures to deal with congested paths. However, it is unlikely that pricing would be effective as the primary instrument to allocate transmission access, coordinate its use, and plan for new resources. The bulk power grid is technically complex. It can be reasonably argued that even its current owners do not fully understand apparently simple concepts such as "capacity." Recent studies in the power engineering literature indicate the difficulty of planning in a competitive environment (Adamson, et.al, 1991; McCalley, et.al., 1991). An advantage of the RTG is that it would not be limited solely to prices as a means for allocating transmission resources. The RTG could specify conditions for access, consistent with the provisions of the Energy Policy Act. The extra flexibility to use non-price conditions for access could lead to increased efficiency.

A.3. Centrally-Mandated Prices

Regulatory control of transmission access at the federal level is consistent with Options 2 and 3. It is less relevant to the traditional vertically integrated utility structure of Option 1. The political pressure for mandatory access arises from both the independent power sector and the generation-deficient municipal utilities. A regime of mandatory access would look rather different in each of the options, depending upon how the federal mandate was implemented. The key variable determining the variations is the treatment of opportunity costs in the pricing of mandated transactions.

A centralized determination of the cost of transmission services has the problem that it is difficult to account for individual circumstances. The FERC has recognized that transmission services provided by a utility for third parties have opportunity costs. Moving from the principle of recognizing these costs to the practice of estimating their magnitude for pricing purposes is a substantial step. At one extreme, a liberal view of lost opportunities can result in very high estimates of an appropriate transmission price. The practical result of such estimates may be very little in the way of actual transactions. This kind of approach may result in substantial limits for third party users. Without the ability to have low cost access to the network, market share for the utilities is maintained.

At the opposite extreme, a verifiable standard for identifying opportunity costs may be so strict as to deny their reality in practice. A compromise solution that would recognize opportunity costs, yet allow access, would be to price access at long-run incremental cost (LRIC). Yet LRIC for firm transmission would be too high in many circumstances. The actual cost that a transmission user imposes on a system may be much less than the cost of expanding the system to satisfy that user's demand. In other situations, LRIC may be less than the true cost that a user imposes on the system. For example, LRIC might not account for siting constraints and delays that add to the cost of providing transmission services. LRIC also fails to provide users with the right signals for expansion of the network.

Another approach using centrally mandated-prices would be to set a price cap, perhaps at LRIC, and allow utilities to negotiate lower prices when the market allows (see Einhorn, 1990). Although this would make regulation more flexible, it would not solve the basic problem of asymmetric information about transmission costs. The greatest potential for efficient application of a price-cap approach to the pricing of transmission access would be in geographical regions where there competition is already relatively strong, as evidenced by many buyers and sellers that can access a high-voltage transmission bus. The Palo Verde switchyard in Arizona is an example, but this is more the exception than the rule in the U.S.

Prices that are mandated centrally by the FERC would amount to a de facto open access system with no limits on the parties seeking to make transactions. It is difficult to imagine exactly how such a system would work in the absence of a centralized grid authority that would apply some kind of rationing method through either price or non-price mechanisms.

A.4. Geographical Spot Pricing (Node Pricing)

This proposal is a version of the spot pricing theory of transmission cost pricing developed by Caramanis, Bohn and Schweppe (1986), Schweppe et. al. (1988) and more fully articulated by Hogan (1992). When an electric power network is efficiently dispatched, the marginal value of transmission between any two points in the system is equal to the difference in the cost of generation at those points. The costs of generation at two points in the system may differ because there are line losses in moving power from one point to another or because transmission capacity constraints impose a congestion cost. The generation cost difference is a natural choice for the price of transmission services. At these prices, a generator should supply power to the grid if, and only if, the marginal cost of the generator plus the price of transmission to the destination is less than the marginal cost of generation at the destination.

One of the main virtues of node pricing is that it is able to deal with the troublesome problem of loop flow, also called unintended power flows. In the Hogan proposal, generation is dispatched efficiently conditional on transmission constraints. Implicit prices for transmission between node *i* and node *j* are determined *ex post* and are equal to the differences between the costs of generation at the two nodes, plus line losses. If unintended power flows cause congestion on a transmission path, the implicit transmission price is increased. This occurs either because congestion limits the capacity on the transmission path, so that the difference in nodal generation costs increases, or because congestion leads to increased line losses, or both. Each user of transmission has to pay for the right to send power across a desired path. Provided all users subscribe to the principle of node pricing for transmission, unintended flows are properly priced because the node prices reflect the true cost, including unintended flows, or sending power across any path, whether or not that past is the physical circuit that a generator desires for sending power from one node to another.

The main difference between the Schweppe version of node pricing and the Hogan version involves timing and information. Schweppe envisioned true spot markets. In the case of electricity this could mean a substantial degree of fluctuation and large informational burdens as the relevant spot price would vary from minute to minute. Other commodity markets settle trades over much longer time intervals. In natural gas, for example, the spot interval is one month. Furthermore, because of real-time network interdependencies, the true spot price is in some sense the result of dispatchers decisions that are easier to report ex post than to forecast or communicate instantaneously. Therefore, Hogan proposes that the system be operated in the current fashion by a number of loosely coordinated control centers, and that node prices be computed ex post assuming the dispatch was efficient.

Efficient dispatching is an important element of node pricing. Without efficient dispatch, generation costs at each node would not correspond to the marginal value of power, and the transmission prices would be meaningless as a measure of social value. Efficient dispatch does not mean that prices must be determined in a perfectly competitive market. Monopoly owners of transmission services may dispatch their resources efficiently. If their internal marginal generation costs were public knowledge, they could be used as the basis for transmission prices. Unfortunately, if internal values are private knowledge, a monopolist could misrepresent them in a way that codifies monopolistic pricing.

Consider a transmission monopolist who serves demand at point D, owns a line from point O to point D, and owns a generating resource with a marginal cost m at point O. Suppose the line has no losses or capacity constraints. Let p^m be the monopoly price at point D ($p^m = \dfrac{m}{1 - 1/\eta}$, where η is the magnitude of the elasticity of demand at D). The monopolist's internal marginal value of power is m at both ends of the transmission line. However, suppose the monopolist could misrepresent that the internal value at point D is p^m. Node pricing would result in a cost of transmission equal to p^m - m, which merely would serve to sustain the transmission owner's monopoly. Of course, this inefficiency would be mitigated if the monopolist's power to misrepresent values were limited, perhaps as a result of auditing of actual transmission operations.

A second problem with node pricing is that it does not necessarily provide efficient signals for the expansion of a transmission network. Economies of scale and cost complementarities in a transmission network suggest that local prices may be a poor signal of the most desirable way to expand the network, although this is a subject for further study.

Hogan suggests that his version of node pricing is compatible with the existing institutional structure, and therefore would apply to our Option #2 as a basis for pricing transmission to private producers. There is some reason to question this assertion. Implementing node pricing requires an initial definition and allocation of capacity rights. Where transmission owners have private information about the network and this forms the basis of market power, it is doubtful whether a truly unbiased capacity definition and allocation process would or could occur. It is difficult enough without private information to define capacity in a electricity transmission network. Where private information is ubiquitous, the prospects are dim. Therefore, it is best to think of Hogan's node pricing as applicable primarily to our Option #3, where spot markets are the dominant institution and market power issues are less large a consideration. In this kind of more competitive setting, the assumptions of Hogan's node pricing are more consistent with the institutional structure.

A.5. Summary

Table 9 summarizes the feasibility of each transmission proposal with respect to the regulatory policy/industrial structure options that we have outlined. In the next section we consider how the transmission policy alternatives might perform with respect to important economic criteria.

Table 9. Feasibility of Transmission Policies in Alternative Regulatory Futures

	Transmission Policies			
	Business as Usual	Regional Transmission Groups	Centrally-Mandated Prices	Node Pricing
Option 1: Vertically Integrated IOUs	NA	Y	NA	NA
Option 2: Mixed V.I. and Competition	NA	Y	Y	NA*
Option 3: Spot Markets	NA	NA	Y	Y

* Applicable only with considerable difficulty in assigning capacity rights.

B. Policy Evaluation

The feasibility of a transmission policy in a particular regulatory regime says nothing about its desirability. In this section we examine more closely the performance (or potential performance) of the transmission proposals with respect to important economic criteria. The criteria we consider are: (1) efficient dispatch, (2) reliability, (3) choice of service quality, and (4) incentives for efficient investment.

B.1. Efficient Dispatch

The existing institutions in the U.S. provide for reasonable efficiency in the utilization of generating resources. This is accomplished in the "business as usual" scenario by central dispatching of units within a utility's control area. Regional transmission groups could preserve centralized dispatching, as demonstrated by the operations of existing power pools. Node pricing implicitly assumes centralized dispatching. Without efficient dispatch, node prices are unreliable indicators of transmission costs.

Clumsy regulatory intervention may have more potential to cause harm than improvement in the utilization of existing assets. The mandated access policy carries the greatest risk in this regard. If mandated access results in a pattern of generation that displaces efficient production with inefficient production, then it is not clear whether the net effect is positive.

B.2. Reliability

The existing bulk power system was built with reliability objectives in mind. As wholesale trade has increased, there is a perception among power engineers that the safety margin has declined. To a large degree, reliability in the bulk power system is a coordination problem. The interconnectedness of the network means that many real time actions are required to control or contain disturbances that may originate locally, but propagate throughout the system. While new technology is increasingly available to improve response time and automate coordinated response, this is offset by increasing the number of entities involved in managing or using the network.

The transmission policies are differentiated along this dimension in much the same way as they are with regard to efficient dispatch. Existing institutions, either "Business as usual" or regional transmission groups, are capable of maintaining a high level of reliability. Mandated access could cause some stresses by overloading particular links, or failing to require sufficient emergency co-ordination obligations. Node pricing should result in high levels of reliability because centralized dispatching is assumed.

B.3. Choice of Service Quality

Transmission services can be differentiated according to several characteristics. These include the extent to which the service is "firm," the probability of forced outages, the voltage level (and whether transmission is AC or DC), and the location of the service (is the transmission service point-to-point or area-wide?). Users of transmission services value these characteristics differently, and proposals that allow choice in service qualities are likely to make better use of scarce transmission resources.

Both "business as usual" and regional transmission groups permit the design of pricing alternatives for transmission services with different qualities. In node pricing, each holder of a transmission capacity right is entitled to firm service over a contract path. Thus all services are "notionally firm" in the node pricing methodology. This is a disadvantage of this costing proposal, because it does not allow purchasers of transmission rights to elect different qualities of service.

Centrally-mandated prices are unlikely to provide for choices in service quality. If prices are based on the costs of transmission upgrades, the implied service quality would be firm. Under these conditions, transmission access would be required to be purchased on a firm basis when buyers might prefer a lower cost non-firm service.

B.4. Efficient Investment

This criterion speaks to the long run evolution of the electricity market. Transmission capacity is, by and large, a scarce resource. Any policy must encourage efficient expansion of the system. Existing institutions have been moderately successful at this process, but not enormously. With respect to incentives for new investment, the main difficulty with the "business as usual approach" has been incomplete coordination among transmission owners who are impacted by expansion decisions.

Most of the reform proposal promise to do worse instead of better. Centrally-mandated prices are likely to lead to inefficient investment in the network. If buyers of transmission services have the right to force expansion when service is not available, the result may be too much expansion or expansion at the wrong place or time and in the wrong amount. If transmission owners are not obligated to expand, centrally-determined prices that only allow the owner to break even could result in too little investment. Owners of the assets would not achieve any substantial benefit from such investments and may suffer competitive losses by strengthening the position of others.

Node pricing would promises efficient signals for new investment only if the transmission cost function is well-behaved (i.e. concave). Unfortunately, there is every reason to believe that this is not the case (see, for example, Baldick and Kahn, forthcoming).

The regional transmission group allows a forum for the evaluation of alternative options to expand the network in a cost-efficient manner. Although private interests will attempt to promote a transmission resource plan that minimizes their individual costs, this strategizing can be checked through administrative oversight. While RTGs may encounter strategizing behavior by members that would distort investment decisions, they may improve on "business as usual" by resolving impacts on neighboring transmission systems. Both the costs of strategizing and the ability to internalize transmission impacts depend on the judicious choice of the size of the regional transmission group and on the conditions for membership.

B.5. Summary

We summarize this discussion in Table 10 where we rate the policy alternative by high performance (H), medium (M) or low (L). Consistent with the requirements of the Energy Policy Act of 1992, all of the policy options assume a system of open access to wholesale generators. This is a significant departure for the "business as usual" option. It is included primarily as a bench mark against which the other options may be evaluated.

Table 10. Rating Transmission Proposal on Key Criteria

	Criteria			
	Efficient Dispatch	Reliability	Choice of Service Quality	Efficient Investment
Business as Usual	H	H	H	M
Regional Transmission Groups	H	H	H	M-H
Centrally-Mandated Prices	M	M	L	L
Node Pricing*	H	H	L	L

* Assumes central dispatching

VI. The Economics of Partial De-Integration

The developments surveyed in this chapter raise a number of interesting questions. In this section we look broadly at the value of competition in regulated industries, where the focus of competition policy should lie in this industry, what guidelines the regulator should observe, and what sort of an institution the regulated firm becomes under a regime where competition is mixed with regulation.

A. Value of Competition in Regulated Industries

Recent theory on regulation consistently raises the theme of imperfect information. The "principal-agent" model casts the regulated firm in the role of an "agent" acting on behalf of a social regulatory "principal." The principal is nominally in charge of the agent, but can only monitor the agent's behavior to a limited degree (Baron and Besanko, 1984; Laffont and Tirole, 1986). In such a setting, the competitive fringe can become a valuable auditing tool for the regulator by helping to uncover the true costs of the regulated firm.

This framework is particularly relevant to private power, where the avoided cost concept provides a natural opportunity to observe the cost structure of the regulated firm. Private producers have a strong economic incentive to discover the costs of the regulated firm, since these become the basis on which they will be paid. The complex regulatory litigation over avoided cost, which has reached its acme in California, becomes a setting to pursue more general regulatory goals. Thus the tendency of regulators to use avoided costs for other regulatory functions (such as evaluating demand-side programs) indicates their importance as a cost-revelation process. The intricate computer simulation modelling used in the California regulatory process also facilitates the "unbundling" process, whereby the different aspects of cost of service become more well-defined and measurable. Presumably, it is the profit motive of the private producers which makes them a superior auditor of the regulated firm. By contrast, the regulatory agency itself is weaker, less capable and less motivated than the private producers.

In practice, the audit function will occur in two distinct settings. Private producers being paid on some kind of short-run marginal or avoided cost basis will focus attention primarily on the operational characteristics of the regulated firm. If the regulated firm is operating an "overly constrained" system, then marginal and avoided costs will be low compared to a more optimal configuration. Many operating constraints limit power system flexibility, in particular, the off-peak "minimum load" problem is fairly widespread (Le, et.al., 1991). Private producers being paid avoided cost are in a position to propose changes in operating procedures that will lower total costs and raise their own payments.

The other setting where the private producers may serve the audit function involves long-run capacity acquisition. Here too, the regulated firm must defend either its selection methodology, or its results, or both to the regulatory commission. The private producers have the opportunity to participate in adjudication of this kind, and try to influence the process in a direction beneficial to their interests.

The auditing function of the private producers is not a short-cut which will eliminate all regulatory oversight. The self-interested positions adopted by private producers in adjudication are not necessarily truth-revealing. While they can frequently shed light on inefficient operating practices or planning procedures, positive recommendations will necessarily involve strategic goals. Private producers will always see substantial avoided costs, the demand for more power and the corresponding higher costs of acquiring it, in any situation. Regulatory scrutiny must extend to these claims as well.

The usefulness of the "competitor as auditor" paradigm for understanding the role of private power depends upon the ultimate market share. What if the competitive fringe can expand its control of the market and become the dominant source of supply? Then the audit function will ultimately be replaced by market forces acting to control supplier behavior. This outcome is fairly remote at the current stage of development. Moreover, it will be very difficult to determine for quite some time what the ultimate prospects may be for the fully competitive outcome. These uncertainties motivate our next issue.

B. Can the Wholesale Power Market be Competitive?

If the answer to this question is yes, then regulation of bulk power supplies will ultimately wither away. If the answer is no, then regulators will have to decide whether protecting the independent private power sector is worthwhile to preserve the benefits of the auditing function described above and the increased potential for technological innovation.

A major factor affecting this decision is the role of unregulated utility affiliates. At least forty investor-owned utilities have formed affiliated or subsidiary companies that now participate in the private power market (RDC, 1990). There is a potential for abusive self-dealing under these circumstances which has already been identified. One well-publicized case of this kind involves Southern California Edison (SCE) and its affiliate Mission Energy. Mission Energy is a 50% partner in the Kern River Cogeneration Company (KRCC), a large QF which sells power to SCE. The California Public Utilities Commission (CPUC) found that the contract between KRCC and SCE was over-priced. The difficulty involved contract clauses which essentially allowed non-firm power delivery conditions, while paying prices that were intended for firm capacity. The CPUC disallowed the collection of the difference between the non-firm value and the contract capacity price, which amounted to $48 million with interest (CPUC, 1990).

Concerns similar to the Mission Energy-KRCC-SCE case may follow from an increasingly dominant role of utility affiliates in the private power market. There may be a danger of reciprocal dealing, where the affiliates of two regional utilities and their corresponding regulated cousins agree to collude with one another. Regulated firm A may contract exclusively, or preferentially, with the affiliate of the firm B, and regulated firm B deals exclusively, or preferentially, with the affiliate of A. Other forms of collusion are also possible.

It is useful to inquire about the forces that would produce a private power industry structure dominated by unregulated utility affiliates. There are several trends favoring market domination by affiliated producers. On the cost side, competitive bidding for long-term contracts has effectively raised entry barrier against small firms. Preparing proposals in response to RFPs can involve expensive site acquisition and engineering investments. An interesting empirical study of competitive bidding in Maine showed the utility placing substantial emphasis in its evaluation on "project viability" factors such as site control (Eastman-Perl, 1991). Utility affiliates all appear well capitalized, since they are financed largely by retained earnings from the regulated side. Further the affiliates may be willing to settle for lower returns than other competitors. Finally, utilities as buyers are likely to be better disposed to proposals from utility affiliates because of "cultural affinities." The affiliated firm is likely to "speak the same language" as the purchasing utility. This means using similar terminology, having a reputation for reliability from the parent firm, and possibly relying on subsidized services from the parent firm.

The extent to which utility affiliates dominate the private power market will be limited by new entry from large industrial firms. Oil and chemical companies with an interest in coal gasification technology are one class of potential new entrant. Texaco and Dow Chemical are already active in this area, and Shell Oil is also a participant in a large-scale project in Europe. Another potential class of entrant is the international trading company. Mitsubishi has already sponsored one large IPP, the 600 MW Doswell project in Virginia.

What if new entry does not materialize, and utility affiliates absorb or drive out other firms? Then, the regulator will be faced with the proposition of supporting private power through this channel, or giving up on the experiment in the long run. Further, PUHCA reform may weaken the ability of regulators to monitor unregulated utility affiliates. In that case, we may end up with the worst of all possible worlds, collusive behavior and no real competition. In this setting, the benefits of nominal competition may turn out to be quite illusory.

C. Regulatory Policy in an IPP Regime

It is not at all clear whether the role of regulation in electricity markets will diminish with a growing market share for independent power production. In fact, a case can be made for the opposite development. There is a strong trend toward greater regulation that is motivated largely by interest in demand-side management (DSM) activities. In addition to regulatory emphasis on DSM, there is also a trend in some states towards a greater role for the regulator in planning and managerial decision-making with respect to conventional generation. This function is sometimes called "rolling prudence reviews." In this style of regulation, the capacity expansion plans of the utility are periodically reviewed and subject to pre-approval. Once approved, the utility then proceeds with the plan and recovers the authorized funds necessary to implement the plan. This approach to regulation is best exemplified by the Wisconsin Public Service Commission through its advance planning process. The Nevada Public Service Commission also engages in the exercise of detailed planning. Utilities, as well as regulators, have expressed support for this approach, because it reduces the risk of cost disallowances for new investment.

Even where the regulator explicitly encourages competition and private power production, there can be a dominant role for the regulator. This is the paradigm envisioned by the FERC's "bidding NOPR," which postulated extensive regulatory review of bid evaluation criteria. To date, only California and Massachusetts have shown much enthusiasm for litigating and adjudicating the details of bid evaluation. In other states, the regulator has usually just reviewed the outcome of the competitive process. As an alternative, the regulator can set broad guidelines for bid evaluation, leaving the utility to implement a system of its own design that meets the guidelines. This is the solution adopted in New Jersey.

Regulation in a market with a competitive fringe will inevitably be complicated by conflicts among the objectives which the regulator is trying to achieve. Social cost minimization can lead to very different outcomes than ratepayer cost minimization. These differences are common to DSM programs. They also arise in the private power sector through the definition and use of avoided cost concepts. Jurewitz (1990) points out a number of ways in which ratepayer cost minimization can come into conflict with social cost minimization when avoided costs become endogenous to the regulatory process. For example, in assessing the need for new generating capacity, is it reasonable to count the reduction in avoided cost payments as a benefit of new capacity? Jurewitz argues that since these are transfer payments, they should not be counted. Since the California regulators appear to consider this effect, then social costs may be increased inefficiently by building too much capacity.

Environmental externalities are another important arena where social and ratepayer cost minimization can lead to different decisions. Utility regulators are beginning to grapple with externality costs in planning and operations. There are substantial uncertainties associated with estimating these costs and a variety of ways in which they can be used in the planning and regulatory setting. In addition, there are frequently boundary issues that arise. Should state regulators address externality issues that lie beyond their domain of authority? What, for example, is the value of a renewable energy technology that offsets pollution in another state? Should a bidding system incorporate this effect, or will doing so contribute to an economic disadvantage for the local community?

D. Utility as the Residual Risk-Taker

In a regime where private power plays a substantial role, the regulated utility will still retain its obligation to serve. Planning to meet that obligation, however, may become increasingly difficult. The demand for new capacity facing the utility is likely to become more uncertain. In addition to the ordinary uncertainties associated with end-user demand, the utility will face an resource availability uncertainty. The source of this second uncertainty will be the potential failure of private power projects with which it has contracted. Private projects can fail at the development stage or at the operational stage. The former is probably more likely than the latter, but it is still too early to predict relative or absolute failure rates.

In the event that the utility must fill an unanticipated capacity need, it is likely that it will not be able to select a particularly efficient source of supply. Given the very short lead times facing the utility, about all that would be possible would be to purchase combustion turbines. If this type of capacity was, in fact, needed by the utility, there is no loss. Alternatively, if a neighboring firm could sell excess capacity at a reasonable price, there would be little economic cost. These two possibilities cannot be expected to be generic, so the expected outcome would be some inefficiency. Moreover, contractual remedies do not appear, as yet, to offer much relief. Private power contracts do have liquidated damages provisions that address the premature termination contingency, the amount of money is relatively small. Mostly the damages are about $20/kW (Kahn, 1991), which is only about a third of the annual capacity deficiency charge of a large power pool, for example.

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