Competitive Markets for Electricity Generation

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The Trend toward Competition

This paper discusses the feasibility of replacing regulation or state ownership with market competition in electric power generation. Interest in competitive electricity markets has been stimulated by recent experiences in the United Kingdom and Brazil with privatization, with deregulation in the United States, and with partial reform in Norway. While the Thatcher government policy offers lessons about the process of privatizing a state monopoly enterprise, the American experience becomes relevant to our understanding of how increasingly competitive markets for electricity actually work. The continuing growth of competition in American electricity markets is an unanticipated consequence of the 1978 passage of the Public Utility Regulatory Polices Act. Designed as a conservation measure, PURPA established the right of cogenerators and Independent Power Producers (IPPs) to sell electricity to local regulated Investor-Owned Utilities (IOUs).

Such rights were broadened substantially by the passage of the Energy Policy Act of 1992 which requires transmission line owners to wheel bulk power (Walters and Smith 1993). Thus, under current federal regulations nonutility power producers can sell electricity to any utility on the grid. Furthermore, in April 1994, the California Public Utility Commission adopted a policy establishing complete open access to all power producers. By 1996 independent generators can compete to sell electricity directly to large industrial customers, effectively bypassing traditional utilities. By 2002, the policy permits all electricity consumers, regardless of size, to purchase electricity

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from *any* utility or independent generator on the grid. No longer will the consumer be restricted to buying electricity from the local utility. A competitive market for generation will have been established (Hoffman 1994).

There are further lessons to be learned from the way the natural gas market has developed in the United States following deregulation. Particularly relevant have been the separation of production, pipeline transportation, and distribution into independent operations; the growth of the spot and futures market for gas, and the latter's replacement of the long-term contract in the buying and selling of natural gas (Doane and Spulber 1994). In the United States, the majority of natural gas sales to local distributors are on the spot market (Lyons 1990).

The system evolving in the United States provides increasing competition and diversity among generators. They vary from established utilities, IPPs, and cogenerators to small producers that use renewable fuels and other nonutility generators. In 1983, the NUGs provided 2.5 percent of total United States generating capacity, by 1991 they provided 9 percent of the total and were building over half the new capacity installed in the nation (Michaels 1993). Once the genie was out of the lamp, the benefits of competition insured that more open markets for generation would spread.

The European Community is addressing these same issues and has agreed to draft directives calling for open access in energy markets. As of January 1993, the European Commission seeks to let large users of electricity—those using 100 gigawatts or more of power per annum (aluminum, steel, chemicals, glass, and fertilizer)—to purchase electricity from any supplier in the Community. Energy Commissioner, Antonio Cardos e Cunha (in the *Financial Times* 1992), summarizes the goal,

> Our aim is to transform the energy market in Europe—which is fundamentally national and based on administrative focusing on price—and replace it with a European unit in which cross-border trades could be significant and prices would react according to negotiations between buyer and seller.

The paper is organized as follows. The next section deals with the twin ideas that the generation, transmission, and distribution of electricity is a natural monopoly and involves only technical issues. The following three sections present a model of competitive generation, outline the major advantages of competitive electricity generation, and discuss how electricity would be priced in a competitive market. The next section compares and contrasts how the market addresses the problem of risk with the way it is dealt with under regulation or state ownership. The final section presents a summary and conclusion.

A Change in the Climate of Ideas

The British and American reforms arose in part because two fundamental ideas have been successfully challenged during the last two decades. The first idea is that the electricity industry is a natural monopoly. The second, independent but complementary, idea, particularly influential in Europe, is that the generation, transmission, and distribution of electricity raise purely technical problems to be solved by engineers.

Ideas have consequences. Any discussion of the electricity industry always starts with the observation that the industry is capital intensive and, because power cannot be stored, it must be generated so as to meet instantaneous demand. These characteristics coupled with the natural monopoly argument are said to justify government franchising and regulation or, alternatively, state ownership.[1]

The notion that the provision of electricity presents only technical issues naturally justifies the vertical integration of generation, transmission, and distribution into a state-owned monopoly. It is worthwhile exploring the challenge to these two ideas in greater detail because opening up the debate has created an intellectual climate more conducive to reform.

Natural Monopoly

The traditional economic justification for the regulation or state ownership of electric utilities is that utilities are natural monopolies. Economies of scale and scope, and the economies associated with vertical integration mean that unit costs decline throughout the relevant range of production as output increases. Such economies preclude competition, according to the conventional view, because a single firm could supply the entire service area at lower cost than could two or more firms. Given its cost structure, an established utility could undercut its rivals and drive them from the market. Moreover, attempted entry represents a waste of resources either because of an unnecessary duplication of facilities or because such investment would not be viable in the face of undercutting. Secure from competition, the monopolist would exploit the consumer if not for regulation or state ownership.

[1]The latter never proved popular in the United States except for small municipal distribution companies and two huge Federal power facilities, TVA and Bonneville.

During the last 20 years, a growing body of evidence, primarily from the United States, has undermined the view that electric utilities are natural monopolies (Hammond 1986). Leonard W. Weiss (1975: 136) argues that the postwar technological trend toward building larger generating plants, in the United States, ended in the mid-1960s, "Most important regions could support enough generating plants to permit extensive competition if the plants were under separate ownership and had equal access to transmission and distribution."

In the late 1960s the conventional wisdom in the industry was that new plants burning fossil fuels had to have a generating capacity of from 1,000 to 1,500 megawatts and that the optimal capacity of a nuclear plant might be even larger. As Edward Berlin, Charles J. Cicchetti, and William J. Gillen (1974: 9) observe, thermal efficiency is not the whole story; reliability plays a role:

> The effect of unit size on reserve requirements is a straightforward problem. The contingency to be guarded against is that a particular unit will not be available when needed. If generating capacity consists of a large number of small units, risk is spread over each of the units.... The forced outage rate for fossil-fueled plants over 600 mw is more than twice that of plants below 600 mw.

Within bounds, the implication is clear: smaller plants are more reliable than large-scale plants. When dynamic reliability is played off against static design efficiency (economies of scale and scope), the optimal scale for plants is smaller than originally thought. Finally, a number of studies suggest that economies of scale and scope in the generation of electricity may not be significant enough to undergird natural monopoly.[2]

William J. Baumol, John C. Panzar, and Robert D. Willig (1982) argue, in their seminal work *Contestable Markets and the Theory of Market Structure*, that even if economies of scale and scope are present, they are neither necessary nor sufficient for natural monopoly to exist. Making the critical dynamic distinction between fixed costs (costs that are not zero when output is zero) and sunk costs (capital invested in plant and equipment that has no alternative use or opportunity cost), they observe that only sunk costs give an existing firm the cost advantage necessary to insulate it from competition. Absent significant sunk costs, potential entry undermines monopoly pricing; natural monopoly is not sustainable. Such markets are said to be contestable (Panzar and Willig 1977).

[2]See Christensen and Green 1976, Huettner and Landon 1978, Cowing and Smith 1978, Stewart 1979, and Jaskow and Rose 1985.

While it is not obvious that electric markets can legitimately be classified as contestable, multiproduct production, uncertain demand, risk aversion, and interproduct (interfuel) substitution are all conducive to potential entry (Sharkey 1982). Don Coursey, R. Mark Isaac, and Vernon L. Smith (1984: 111) conclude from their research that

> the most significant result . . . is that the behavioral predictions of the contestable market hypothesis are fundamentally correct. It is simply not true that monopoly pricing is a 'natural' result of a market merely because firms in the market exhibit decreasing costs and demand is sufficient to support no more than a single firm.

Thus this research suggests that competition can be substituted for government regulation and state ownership to assure good performance in, at least, the generation of electricity.

Technological Efficiency

The other intellectual tradition that has been influential in the governance of electric utilities argues that the generation, transmission, and distribution of electricity can be reduced to a set of purely technological problems. Because engineering efficiency should guide the design and development of electric power facilities, this view concludes that engineers should operate such facilities as state enterprises. The reliable provision of electricity is vital to public welfare. The public is best served when a staff of civil servants, trained in engineering, attend to these technical matters.[3]

Yet the generation and distribution of electricity is not primarily, let alone exclusively, a matter of technology. Consider the concept of efficiency. Technological efficiency is always defined as the rate at which an input is converted into an output; a ratio of two quantities. For example, one definition of efficiency is the ratio of work done to energy input. The ratio is less than one, because some energy is dissipated in the form of waste heat during the process that converts energy into work. A process is said to be more efficient than another (see Heyne 1987: chap. 6) if, in the first process, a higher proportion of potential energy is converted into kinetic energy than in the second or, equivalently, if the first process generates less heat loss than the second process.

On that definition, the most technologically efficient means of producing electricity would be the method that converted the highest proportion of the potential energy of its fuel into electrical energy.

[3]In a fascinating discussion, Friedrich A. Hayek (1964) traces the intellectual roots of this approach to policy engineering to the *Ecole Polytechnique* (see his *The Counter-Revolution of Science*, especially Part 1, chap. X, and Part 2, chap. IV.).

By that criterion, nuclear plants are more efficient than coal-fired plants, and coal-fired plants are more efficient than are hydrogenerating stations.

If electricity were the only commodity of economic value, the technological and economic concept of efficiency would come down to the same thing. But of course, literally tens of thousands of goods and services are valuable. The inputs, including fuel, that are necessary to generate electricity are scarce resources in the sense that they have many alternative uses—alternative uses that also satisfy human wants. Thus, the most efficient way to produce electricity, from society's point of view, is the method that maximizes the difference between the value of output and the value of inputs.

The objective data of the engineer (conversion rates) is only one factor in the determination of the subjective values that measure economic efficiency. Hydroelectric power plants, the least technologically efficient plants, may be the most economically efficient means of producing electricity when the value of the resources consumed in production and the environmental consequences of hydropower are taken into account.

Writing 70 years ago, the engineer Otto Goldman (1923: 84), using different terminology, makes the same argument,

> It seems peculiar and indeed is unfortunate that so many authors in their engineering books give little, or very little, consideration to costs in spite of the fact that the primary duty of the engineer is to consider costs in order to obtain real economy—to get the most power, for example, not from the least pounds of steam, but from the least number of dollars and cents: to get the best financial efficiency.

Absent technological change, objective engineering data on energy conversion rates remain constant and provide an unambiguous ranking of the different methods for producing electricity according to technological efficiency. By contrast, the ranking of production methods according to economic efficiency can change as the result of either a technological innovation or a change in the relative value of inputs. An example of the latter would arise if the market valuation of nuclear fuel rose and the price of coal dropped. Under such circumstances, the value of the resources consumed by coal-fired plants might drop below that of nuclear plants, per unit of electricity produced, and coal-fired plants would become more economically efficient than nuclear plants.

A shift in subjective valuation changes the measure of economic efficiency while having no effect on the measure of technological efficiency. The twin measures of efficiency are fundamentally different. In terms of human welfare, the most efficient means of production is always gauged in terms of economic efficiency, the ratio of the subjective value of output to the subjective value of inputs.

The concepts of engineering and economic efficiency diverge for two reasons. First, there are different methods of producing electricity, each of which uses a different combination of inputs. These inputs are scarce; they have alternative uses. Which use is the more valuable depends on subjective assessments revealed only by market exchange. Second, electricity is not a single good but a multiproduct having many characteristics including peak and off-peak timing of production and consumption, and reliability of service. A method of production that is efficient for producing a base load may be inefficient for meeting peak-load demands. Narrow technical efficiency provides no meaningful criterion for ranking production methods when inputs have alternative uses or when production involves complex goods with multiple characteristics. Electricity is just such a good. The higher dimensionality of the concept of economic efficiency and the greater information costs of measuring economic efficiency present a problem that is best solved by voluntary market exchange.

What makes the notion of objective technological efficiency so congenial to the idea of state ownership and operation of this vital industry is that it avoids the necessity of obtaining and acting on information about market valuation. Technological efficiency seems to point to *the way* of generating and distributing electricity. All the information necessary to do so is known by the civil servants acting on behalf of the public interest.

The natural monopoly thesis and the notion that producing electricity is a purely technical matter are powerful ideas that die hard; they have shaped the structure and governance of the electricity industry throughout this century. This paper argues that, to the contrary, the efficient use of resources to produce and distribute electricity requires information about relative valuations that can be generated only by market exchange.

Competitive Generation

Theoretical arguments, statistical evidence, and—of increasing importance—experience favor the viability of competitive markets for the generation of electricity. In general, reform means the substitution of market competition for state ownership or government regulation to ensure good performance. The nature of the particular reform necessary to introduce competition into the electricity industry depends, of course, on the current structure of the industry. If the industry is a state-owned monopoly, as, for example, in the case of

Electricité de France (EDF), then reform means full privatization and the separation of generation from transmission and distribution functions. If the industry consists of investor-owned utilities, subject to government regulation, as in the United States, then deregulation of generation capacity coupled with the separation of generation from transmission and distribution is required.

Elements of Reform

Thoroughgoing reform has four major elements: (1) private ownership of electricity industry facilities; (2) open access for generators to transmission facilities; (3) a minimum of three independently owned generating stations that could potentially compete for consumers within each regional electricity market or service area;[4] and (4) separation of generation from transmission and distribution.[5] More radical reform would be difficult because privatization, restructuring, and complete deregulation of transmission and distribution facilities remain controversial.

By contrast, decentralized, competitive markets at the generation stage are not only conceptually desirable, but are becoming increasingly important in the United States. John Tschirhart (1991: 27) observes, "Entry of new firms into the electric power industry is becoming commonplace. The entrants typically are unregulated firms that compete with regulated electric utilities only in the generation stage of the latter's integrated structure." By 1990, a decade after the reform movement got under way in the United States, cogenerators and unregulated IPPs were building more generating capacity than were traditional utilities. For example, Southern California Edison buys 30 percent of its power from NUGs. The Midland Co-Generation Project in Michigan consists of 12 gas turbines with a generating capacity of 1,343 megawatts. In New York State, construction of new generating capacity is determined by competitive bid with many contracts being awarded to NUGs (Tschirhart 1991). The Alamita Company, in Arizona, is an independent power company that sells electricity to bulk customers, Tucson Electric Power Company, and Southern California Edison (Herriott 1989a).

[4]Producers need not be located within the region, but only interconnected to the market via transmission lines. Independent producers, in some instances, could be created by breaking up existing generating capacity into a (relatively small) number of companies that would compete to sell electricity. Other competitors in a regional market could include IPPs and cogenerators.

[5]One approach is to treat the transmission grid as a regulated common carrier providing access and central dispatch to all power producers. Distribution companies could be regulated as regional (private) monopolies.

Compared with the deregulation of IOUs, privatization of a state-owned monopoly requires a complete and fundamental change in the structure of ownership and property rights in the electricity supply industry in order to obtain the benefits of increased efficiency and innovation. A shift from public to private ownership refocuses the goal of the producer toward profits. Pursuit of the latter provides a strong economic incentive, in a competitive environment, to improve and maintain the quality of customers services, monitor costs more closely, and invest in productivity-enhancing technologies. These incentives are blunted by state ownership. With respect to privatization, the British experience since 1989 seems more germane than does the regulatory reform the United States has been undergoing since 1978.

The Advantages of Competitive Generation

Competitive generation envisions a market within which independent firms compete on the basis of price to sell electricity directly to large industrial customers (bulk wheeling), and to supply electricity, via common carrier transmission, to distributors who in turn sell power to final users (Rozels 1989, Bushnell and Oren 1994). Producers may specialize or diversify by load characteristic. For example, some may prefer to compete for long-term base-load contracts. These firms are likely to own hydro and nuclear power plants. On the other hand, firms with fossil fuel plants might seek to supply base and cycling loads. Finally, producers with gas combustion turbines and cogenerators could compete to meet peak loads. Other firms may diversify and be ready to compete for base, cycling, and peak loads. Peak and off-peak loads are defined by day, week, and season.

Prices charged for each type of service (peak and off-peak load, daily to seasonal) could be established by contract, 24-hour advance notice, and in spot markets. Unit prices could vary by the amount of electricity purchased per period (Wilson 1993). As a result, customers would face more service options and a more complex pricing scheme.

There are a number of advantages to having a variety of types of generators linked to the transmission grid. The first major advantage involves cost savings. At any given moment, power is supplied to the transmission grid by the firm with the lowest marginal costs. Dispatch according to merit (from lowest to highest marginal cost including line loss[6]) saves resources and reduces the cost of generating electricity.

[6]Typical line loss approximates 1 percent per 100 kilometers. Line loss limits the extent of the market, because the loss rate is a nonlinear increasing function of distance.

Because the different plants may have different load characteristics, peak and load duration curves, generating capacity can be more fully utilized and additional capital resources saved.

Moreover, the variety of generating equipment and the larger number of independent producers adds diversity to the system, lowering the probability of widespread equipment failure, and, thereby, reducing the amount of excess capacity required to provide a given level of service reliability. The availability of electricity from alternative suppliers means that generators can coordinate routine plant maintenance. The added flexibility in scheduling repairs lowers plant maintenance costs. These four sources of cost savings mean lower prices to the consumers of electricity (Herriott 1989b).

The second advantage of competitive generation is that a spot market for electricity will develop. The ability to sell electricity on the spot market increases the generator's flexibility in scheduling production. Consider the position of the monopoly producer. The firm must wait for customers to "flip the switch" and demand electricity. In order to meet fluctuating demand, the monopolist must maintain costly "spinning" capacity as a reserve. By contrast, competitive generators can sharply reduce their idle spinning capacity and simply schedule efficient production. They need not wait for customers because they can sell power on the spot market at any time. Efficient scheduling reduces production costs. The dynamism and flexibility of the competitive market is the antithesis of the passive waiting game that the monopolist must play.

Moreover, the presence of a spot market means that less idle capacity must be maintained in order to provide a given level of service reliability. Shortfalls and emergencies can be met by purchasing power on the spot market. Demand and supply are equilibrated by flexible spot prices.

The third advantage of competitive generation is that the market will provide an array of service standards that more closely match the mosaic of consumer preferences (Caves, Herriger, and Kuester 1989). It is a shibboleth of the industry that a utility must stand ready to supply electricity to all demanders at all times. But of course such a standard of reliability is met and maintained only at high cost. Vertically integrated utilities invest in expensive excess (off-line) capacity to ensure a high degree of reliability. For example, gas combustion turbine plants make up much of the spinning standby capacity in the United States.

Not all consumers seek such a high quality of service all of the time. With the option of choosing among competitive generators, distributors have an incentive to discover the level of reliability demanded by different consumers. Consumers could be offered priority service with a schedule of electricity rates increasing with the level of reliability. Customers upon whom infrequent but uncertain service interruptions impose relatively low costs could save (with certainty) by subscribing to lower priced, lower priority service. Conversely, customers for whom interruptions impose high costs would subscribe to higher priced, more reliable service (Smith 1989).

Interruptible service does not mean customers are without service altogether. Rather interruptions involve a reduction in power. Typically in the United States, for example, interruptible residential service means that the consumer's heavy appliances (air conditioner, hot water heater, or space heater) are turned off when the utility sends an electrical impulse that trips a circuit breaker. Full power is restored after the emergency or peak load has passed. In other systems, customers purchase a fuse that guarantees a minimum level of power not subject to curtailment; power use above that level can be interrupted. The higher the minimum level of service chosen by the consumer the higher the price of electricity (Wilson 1989, Woo 1990).

By offering such choices, distributors obtain information about consumer preferences for reliability. With this information distributors know, for instance, how much and at what prices electricity should be purchased on spot markets during peak periods or emergency outages.

In spite of costly excess capacity, outages occur. Unexpected equipment failure or peak demands temporarily greater than generating capacity cause blackouts or rolling brownouts. The resulting random rationing is inefficient because it represents an arbitrary distribution of an unpriced resource—reliable service. By contrast, during an emergency shortage with priority service, consumer service is interrupted in order of ascending priority, from lowest to highest reliability. Because consumers have revealed their preference for service reliability, a priority system reduces the aggregate cost to consumers of interruptions, compared with random rationing.

According to Hung-Po Chao and Robert Wilson (1987), priority service offers significant efficiency gains over random rationing with fixed electricity rates. The authors argue that advances in the microelectronic technologies of metering and control make selective, ordered rationing economically feasible. Similarly, Abraham Grosfeld-Nir and Asher Tishler (1993) found variations in outage costs for a sample of Israeli industries, which suggested to them that there is a potential for large savings if priority service is offered.

Priority service reduces costs in three ways. First, it reduces the excess capacity carried in order to provide the reliability demanded by consumers. Second, when outages occur and service is rationed, priority service minimizes the costs of interruptions borne by consumers. Third, because consumers have revealed their preferences for both the quantity and reliability of electricity service, long-run capital planning is more efficient, hence more cost effective.

Priority service can be fine-tuned by offering rate schedules based on both the frequency and average duration of service interruption, and on whether service would be interrupted only upon prior notification. Those willing to bear the risk of uncertain interruption would pay lower electricity rates. Finally, as Shmuel S. Oren and Joseph A. Doucet (1990) suggest, suppliers can provide interruption insurance with premiums based on the probability of rationing and compensation specified.

A competitive market in electricity generation would offer a much broader array of services than do state monopolies or regulated generators. Perhaps it is not surprising that 70 percent of United States private utilities, facing new competitive pressure at the generation stage, now offer some form of voluntary interruptible service (Strauss and Oren 1993).

Such services are less likely to be offered by either state monopolies or heavily regulated private utilities than by competitive generators precisely because priority service economizes on capital capacity. For a state monopoly, offering priority service would reduce the size of the enterprise and budget, the level of employment, and ultimately power within the bureaucracy. For private utilities operating under cost plus pricing regulation, more capital means higher accounting profits. Moreover, for both state and private monopolists system reliability is a powerful hook on which to hang a request for a larger budget or rate increases. Tailoring service standards to customer demands is the last thing to expect from a state or private monopoly.

The fourth advantage of competitive generation is innovation. Experience in the United States with deregulation of transportation and telecommunication and, on a more limited basis, the electric power industry suggests that competitive pressure tends to make industries more innovative. Competition not only leads firms to be more responsive to consumer demands, monitor costs more closely, and compete on the basis of price, it provides an incentive to be innovative because that may be the only way to get a temporary jump on rivals. Developing a new consumer service, a better method of reducing costs, or a faster way of dealing with problems promises the innovator a competitive edge. Because research and development is risky and offers little reward to state enterprises or utilities with monopoly franchises, evidence suggests that the latter organizations are less innovative.

Competitive Pricing of Electricity

Private producers of electricity seek to earn profits. If their operations are regulated by market competition rather than state regulations governing prices and rates of return, producers will monitor costs more closely at *all margins* and, further, offer electricity at prices determined by marginal costs. Because the cost of generating electricity varies by reliability of service and whether demand falls on a peak or off-peak period, we expect a more elaborate pricing system to emerge under competitive conditions.

Industrial Customers

With competitive generation, industrial customers can purchase electricity from the regional distributor or directly from a generator via bulk wheeling. Industrial users can shop for electricity. Service standards and prices would be negotiable and subject to long-term contract. Unanticipated requirements can be met on spot markets (Schweppe et al. 1988). Retail spot market prices for industrial users would equal wholesale spot prices (determined by competition among generators) plus transmission and distribution charges. The regulatory authority would guarantee open access for generators to the grid, approve transmission and distribution charges, and require that distributors base retail spot prices on prevailing wholesale spot prices.

It may be the case that few, if any, industrial or commercial customers, would want to purchase power on the spot market. Buying and selling electricity at volatile spot prices involves relatively high transaction costs and risk. The point remains that competitive generation makes retail spot markets viable. Also note that with competitive generation, an industrial customer who is buying electricity from a supplier at 11:00 a.m. may be selling electricity to that same supplier at 7:00 p.m. (Rose and McDonald 1991). In competitive markets, the roles of buyer and seller can change periodically.

Residential Consumers

Residential consumers too are in a position to contract with any producer on the network and thus can shop for the most desired type of service and prices. Residential consumers might pay set prices from a menu establishing time-of-day and time-of-year rates, and premiums and discounts based on reliability of service. Prices for interruptible service would vary depending on probability and expected duration of outages and whether or not prior notification is specified. Residential consumers are unlikely to want to purchase power on the spot market. Fluctuating spot prices would generate too much uncertainty for the typical residential user. The vast majority of households are likely to opt for menu prices, based on service characteristics, in part, because such a pricing scheme makes estimating expenditures on electricity easier.

Distribution Companies

With competitive generation, distributors have many options. Indeed, distributors become the most important shoppers for electricity in the system. Depending on the quality of service demanded by their customers, distributors' degree of risk aversion, and their ability to diversify, distribution companies seem likely to purchase their base and expected peak loads by long-term contract with shortfalls and emergency requirements met in the spot market (Doucet 1994). For example, Florida Energy Brokers operate a wholesale spot market for electricity which posts prices hourly.

Transmission Services

An analysis of the pricing of transmission service is beyond the scope of this paper, but a few comments are in order. Private transmission companies would be regulated as common carriers that guarantee open access to all potential suppliers of electricity. The transmission company's role is pivotal as it performs central dispatch. Operating the grid involves establishing network policies and procedures, assigning load to each generating station, maintaining network lines, scheduling energy transfers, and accommodating bulk wheeling.

Transmission rates should be set so that (1) all transmission costs, discussed below, are covered; (2) short-run demand equals the short-run supply of electricity, and (3) price provides guidance for optimal investment in future transmission capacity.

The transmission of electricity is governed by certain physical laws. These should be interpreted as *technical constraints* within which the market determines the quantity and price of electricity supplied at any given time by any given generator. Thermal and voltage limits define transmission capacity (Hogan 1993). Moreover, electricity placed on the grid flows according to Kirchoff's laws—for the purposes of this paper, electricity flows along the path of least resistance. Thus, for example, electricity sold by Generator A to Industrial Customer B may not travel along the "contract path," that is, the shortest line within the network that directly links the buyer and seller. Depending on circumstances, electricity introduced into the network at any point may give rise to "loop flow" affecting all suppliers to the grid. Loop flow can disrupt the quality and reliability of service to everybody taking electricity from the grid at the moment additional power is introduced.

While conceptually loop flow can be a problem, central dispatch is designed to direct traffic so as to avoid problems associated with these technical constraints. Linking a number of independent power producers increases the load diversity of the system and the number of energy transfers per period thus reducing the significance of loop flow (Walters and Smith 1993). As William W. Hogan (1992: 216) argues,

> When loop flow is a small part of power economics then informal swaps can balance out the effects over time, and when all parties are members of the same transmission club, it is reasonable to employ the contract path fiction as a practical accommodation in crafting power contracts.

Network rules would, of course, establish minimum technical standards for putting electricity onto the grid: long-term contracts setting forth transmission rights for each generator, and fees for transmission services. Transmission fees might consist of a two-part tariff: an access charge covering capital costs and a fee set equal to the marginal cost of providing transmission service. Because the latter includes maintenance and congestion costs, fees would vary with the volume and distance power is transferred. When appropriate, a higher congestion fee would be charged short-term users because of the higher transaction costs of arranging dispatch on short notice (Doyle and Maher 1992).

The Market Response to Risk

It is important to understand the market response to the increased risk associated with the introduction of competition into the market for generating electricity. Before discussing this issue, however, it is desirable to outline the sources of risk that are independent of market structure. The production and distribution of electricity is subject to predictable time-of-day and seasonal variations in demand and input prices. In addition, it is subject to stochastic equipment breakdown, unexpected fluctuations in demand that must be accommodated instantaneously, and unexpected changes in input prices, particularly those for fuel.

Typically a vertically integrated state monopoly deals with fluctuations in demand and random equipment failure by carrying excess capacity, including redundant backup capacity. It may also address predictable fluctuations in demand by offering peak-load pricing schemes, although the incentive to do so is weakened by state ownership or regulation. Installing excess capacity is more attractive to the bureaucracy. Peak-load pricing was well understood long before state or franchise monopolies implemented time-of-day service.

Competitive generation produces at least two additional sources of risk: a more complex pricing structure (discussed above), and loop flow problems when independent producers put electricity into the transmission network. But if decentralized markets introduce additional risk, they also provide a broad array of ways of dealing with it. All of these sources of risk potentially influence the quality of service to the final consumer of electricity. In general, the market offers methods to reduce risk and to price risk so that it can be spread or shared optimally.

Fluctuations in electricity prices and interruptions in service generate risk for the buyer and seller. In the case of price variations, the payer finds it more difficult to forecast expenditures and plan accordingly. The seller finds it more difficult to forecast gross receipts. Uncertain interruptions of service complicate consumer and producer planning. The risk borne by a given party depends on the probability of an untoward event (an outage), the magnitude of the event (extent and duration of an outage or the magnitude of an unexpected price change), the costs imposed by the event, and the degree of risk aversion of the affected party. Because reducing risk, transferring risk to parties willing to bear it, and spreading risk among all parties are valuable activities, it is not surprising that the market provides for all three.

Consider how a generator faces the risk of uncertain prices for electricity. First, the producer can sell power by long-term contract to large industrial customers and regional distributors. Contracts specify prices and adjustment clauses. Thus, only a small proportion of its output may even be exposed to unknown price fluctuations (Jaskow 1988). Second, selling on the spot market on a regular basis offers normal returns because prices regress toward the mean over a large number of sales. By selling regularly in the spot market, the producer is reducing risk through diversification. Third, the producer can hedge spot market sales in the futures market.

The futures market for electricity is really a market for future generating capacity, not future electricity. The generator is said to be "long on capacity"; therefore, the firm hedges by selling futures contracts for the amounts and periods corresponding to its desired sales profile. On the other side of the market is a distributor who wishes to hedge against uncertain future prices, so he purchases the futures contract on a take-or-pay basis. (With a take-or-pay contract, the distributor commits himself to purchase a given amount of electricity during specified periods on specified dates; failure to take results in paying the supplier a fee.) Standardized futures contracts reduce transaction costs and are highly liquid. For example, contracts in the United Kingdom's Electricity Forward Agreement Market set quantity at a minimum of one megawatt, duration at weekdays or weekends, delivery in four-hour intervals, and settlement terms (Amundsen and Singh 1992).

Suppose today's future price for one megawatt of electricity delivered in two weeks from 2:00 pm until 6:00 pm is 10.8 cents per kilowatt-hour (kwh). Assume that, in two weeks, the spot price during that period is 10.4 cents. The distributor can either take delivery and pay the agreed upon 10.8 cents or decline delivery and pay the generator four mills per kwh for the amount of power specified in the contract. The distributor can then purchase his power requirements on the spot market at 10.4 cents. In the latter case, the generator receives four mills per kwh from the distributor who declines delivery and 10.4 cents on the spot market for its power. For both the generator and the distributor, there is no uncertainty about the price of electricity for that future period—it is 10.8 cents per kwh. The hedge is exactly the same if the spot price rose to 11.3 cents.

Futures prices are determined hourly in open auctions conducted by brokers for generators, on the one hand, and distributors and industrial users, on the other. The presence of speculators, who never take delivery on take-or-pay futures contracts, only adds bidders and sellers on both sides of the market—which serves to deepen the market and increase its liquidity and efficiency.

Electricity generators already have experience making spot market purchases of fuel, principally natural gas and petroleum, and hedging those purchases in the futures market. The combination of contracting and hedging reduces the risk born by the generator. That, in turn, reduces the risk facing the final consumer of electricity.

Similarly, distributors and large industrial users can mitigate the financial consequences of uncertain electricity price changes by entering into long-term contracts, and by hedging spot market purchases of power. Take-or-pay contracts are ideally suited for such circumstances. Futures markets already exist in Norway and the United Kingdom. New England and Mid-Atlantic power pools, in the United States, are investigating establishing futures markets.

To reduce or spread the risk associated with stochastic equipment failure or unexpected fluctuations in demand, the distributor will have signed contracts with a competitive producer carrying appropriate generating capacity. Moreover, the distributor is in a position to purchase electricity to meet service requirements on the spot market. Because the ability to obtain electricity literally on an instantaneous basis is a major characteristic of service quality, it has a market price. In addition, the distributor has an incentive to discover the final consumer's demand for reliability by offering discounts for interruptible service. The added flexibility of priority service reduces the risk to the distributor that an unexpected spike in demand or equipment failure might otherwise cause.

To reiterate, the ability of a distributor to obtain electricity from a number of suppliers under long-term contract and on spot markets tends to ensure that electricity is made available at lower competitive prices, and that risk-reducing system diversity is enhanced. Intertemporal price risk arising from spot market transactions can be hedged in a futures market for electricity. At present, the development of a futures market for electric power is just beginning, but long-term contracting for electricity, spot market bids and sales, and energy wheeling are a growing part of the market for electricity in the United States.

Conclusion

The technical and economic knowledge exist to permit the substitution of market competition for state ownership or government regulation in the electricity generation industry. The chief advantages of making that substitution include a reduction of costs and lower final user prices, closer alignment between the array of services offered and consumer preferences, and greater incentives for ongoing discovery and innovation.

Generating electricity is capital intensive. Economizing on capacity dedicated to meeting peak-load demand can be a significant source of saving. Potential savings are far greater than those offered by peak-load pricing alone. Competition in generation increases load diversity, thereby reducing the inventory of standby capacity necessary to meet peak loads. The development of spot markets for electricity means that generating capacity can be more fully utilized and less idle reserves need be maintained. In addition, competition provides an incentive to discover the demand for reliability among different customer classifications. Meeting that demand more closely by offering interruptible service saves additional capital resources.

The first principle of competition is marginal cost pricing. Competitive generation provides an incentive for producers to reexamine their cost structure at every margin. Expected cost savings are greater in a competitive environment than are likely to exist under a regime of either state ownership or regulation. Under state ownership, bureaucratic self-interest runs counter to efficient, innovative operation. Regulation entails costly bureaucratic monitoring and political negotiation.

The market is an engine of discovery. Without the information about relative valuations that can only be revealed by market-determined prices, the electricity industry has no meaningful guidance for planning investment, siting plants, deciding on the array of services to offer, or reducing the effects of uncertainty. The structure and governance of the electricity industry today leads to a situation where new plants are built when demand for electricity, at politically determined prices, systematically outstrips capacity and the political will is found to proceed with construction. Siting of plants is reduced to political negotiations. Such negotiations often pay little heed to the implications of market location, fuel transportation costs, and transmission costs. Beyond time-of-day and seasonal rates, little attention is given to the quality of service. Nor is there any surprise in this. Today the industry's stated goal is to offer only the highest standard of reliability for all consumers, whether they want it or not.

Risk management in the electricity industry is synonymous with carrying enough excess capacity to meet any peak load or temporary equipment failure. Whether this approach is economic or not is never addressed. Economic valuations, reflecting consumers' choices registered in open markets, play almost no role in the decisions reached by governments, state-owned electricity facilities, or regulated utilities.

By contrast, the competitive market reduces risk by offering a choice among alternative suppliers of power, by creating spot markets, and increasing load diversification; it allows for the transfer of risk through the creation of futures markets, through prior notification of service interruption, and interruption insurance; and it spreads risk by increasing the number of producers and transactions.

The introduction of nonutility, independent power production 16 years ago in the United States, as part of a larger energy conservation policy, unleashed the forces of competition at the generation stage. The gradual spread of competitive pressures within the industry was not anticipated. Industry spokesmen and academicians have consistently missed the implications of these changes. Many have been far too cautious in estimating the efficacy of competition in enhancing the economic welfare of consumers of electrical power.[7] But perhaps this is not surprising. Market processes are discovery processes. Even informed commentators may not be very good at predicting how the market will solve many of the problems confronting an industry in transition.

[7]An influential example of such reticence is Jaskow and Schmalensee 1983. For a more recent example see Gegax and Nowotny 1993.

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