Expanding Competitive Opportunities in Electricity Generation

Paul L. Joskow

At least since the introduction of state commission regulation in the decade before World War I, followed by the expansion of federal regulation during the 1930s, and continuing to until very recently, the presumption has been that the distribution, transmission, and generation of electricity have economic characteristics that are not conducive to effective competition. As a result, electricity suppliers were given de facto monopoly franchises to provide electricity to retail customers within specific geographical areas. In return for those exclusive franchises, electricity suppliers took on a public utility obligation to stand ready to provide reliable supplies of electricity to all retail customers located within their geographical areas at reasonable rates determined primarily by state regulatory agencies.

Over the past several years several important changes in the structure and regulation of the electric power industry, particularly in the role of competing suppliers of generation, have begun to occur. Probably the most important changes are associated with the growing importance of wholesale power markets, in particular, the development of a competitive independent generating sector made up of power supply entities that sell power to distribution utilities for resale without being subjected to traditional price and entry regulations. Those entities are commonly referred to as independent power producers or nonutility generators.

This article reviews the current status of competitive entry and pricing of electric generating capacity and energy produced by nonutility generators for resale to retail customers and discusses the state and federal regulatory barriers that must be removed to promote the development of efficient competitive markets for electric generation services. The focus is entirely on the generating segment of the electric power industry. It should be recognized, however, that developments affecting the transmission and distribution of electricity have important implications for the evolution of a competitive generation sector and, more important, for electricity costs

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and reliability. Much of the recent discussion in Washington about promoting competition in electricity generation has focused on reforms to the Public Utility Holding Company Act of 1935 (PUHCA). As we shall see, however, PUHCA is only one of several regulatory impediments to the evolution of efficient generation markets.

Traditional Industry Structure and Regulation

In 1990 American consumers spent about $175 billion for electricity. Over 3,000 entities distribute electricity at retail to over 100 million customers. But between 75 and 80 percent of the electricity supplied is provided by over 100 independent private investor-owned utilities. The rest is generated or distributed by nearly 3,000 publicly or cooperatively owned entities that vary widely in size, structure, and ownership form. I focus on the investor-owned utility sector of the industry here.

While investor-owned utilities vary widely in size (no investor-owned utility accounts for more than 5 percent of the nation's generating capacity), they share many common structural and regulatory characteristics. The typical investor-owned utility has traditionally been *vertically integrated* into the generation, transmission, and distribution of electricity. That is, historically, investor-owned utilities typically owned *and* operated all of the generation, transmission, and distribution capacity required to serve the needs of their retail customers or took a joint *ownership* interest in generating facilities operated by another utility.

The retail rates charged by distribution utilities are subject to regulation by *state* regulatory commissions pursuant to state public utility statutes.

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All states rely on similar accounting cost-of-service/rate-of-return regulatory principles to set retail rates. Distribution utilities also take on a legal obligation to provide reliable service at regulated rates to all retail customers located within their service territories.

Investor-owned utilities also make a variety of wholesale transactions. Wholesale transactions are defined as sales by one utility to another utility for resale to retail customers. Those transactions include sales of generating service as well as sales of transmission service. Since the passage of the Federal Power Act in 1935, wholesale transactions have been regulated by the Federal Energy Regulatory Commission (FERC, formerly the Federal Power Commission). Historically, FERC has relied primarily on accounting cost-of-service/rate-of-return regulatory principles to regulate the prices one utility charges another for generation and transmission service. This largely reflected the fact that for many years the bulk of wholesale transactions subject to detailed FERC regulation involved sales by vertically integrated, investor-owned utilities to relatively small, "captive" unintegrated municipal and cooperative distribution utilities over which it was argued integrated utilities could exercise monopoly power. Developments in transmission and coordination technology have also led to increased interconnection between independent investor-owned utilities and to a large increase in wholesale trade in generating capacity and energy between integrated utilities. This has increased the importance of federal (FERC) regulation of wholesale transactions that do not involve "captive" distribution customers and has led to conflicts between state and federal regulatory authorities. Nevertheless, wholesale transactions subject to FERC jurisdiction account for a relatively small fraction of the typical investor-owned utility's costs.

It is important to remember that most operating electric utilities are organized pursuant to state law and are subject primarily to state regulation. As a result, the bulk of a utility's costs are subject to state regulation. The terms and conditions of retail franchises are also determined by state law. A majority of the states also require utilities to obtain certificates of convenience and necessity before building major new generating or transmission capacity, and many states review utility capacity planning procedures and actions.

There is no direct *federal* regulation of entry, supply planning, or facility construction in the electric utility industry. Unlike the case of interstate gas pipelines, FERC has no eminent domain authority or the ability to issue certificates of convenience and necessity to electric power facilities. This is true even if the public utility in question only engages in wholesale transactions. FERC's authority is limited to the regulation of rates and related terms and conditions for interstate wholesale transactions, data-filing requirements, the establishment of a uniform system of accounts, and approvals of mergers between electric utilities. But FERC's ratemaking procedures have important implications for the structure of the industry because they affect the terms and conditions upon which wholesale suppliers of electricity would be able to sell electricity if they found a willing buyer and chose to enter the market.

Many electric utilities are organized within a holding company structure. A holding company may include one or more operating public utility affiliates, as defined under the Federal Power Act, as well as nonutility affiliates. Under the Federal Power Act, any entity that sells power at wholesale for resale to ultimate customers is a public utility whether or not it sells power directly to *retail* customers. PUHCA made public utility holding companies subject to a variety of regulations administered by the Securities and Exchange Commission. PUHCA was passed in response to a variety of financial and regulatory abuses that holding companies were accused of during the 1930s. The act is structured, in conjunction with the Federal Power Act, to fill regulatory "gaps" that may exist when holding companies own operating utilities in more than one state, to guard against beggar-thy-neighbor state policies that may be applied to multistate holding companies, and to limit the formation of multistate holding companies to situations where it can be demonstrated that the holding company promotes the efficient operation of a single, integrated, multistate utility system.

Holding companies owning electric utilities that operate primarily within a single state are typically exempt from the regulatory requirements of PUHCA. These "exempt" holding companies are often subject to state holding company regulations, however, and for our purposes are no different from a "simple" investor-owned utility that is not structured as a holding company. Exempt holding companies account for nearly 50 percent of investor-owned utility generating capacity. Public utility holding companies that own electric utility affiliates in two or more states (multistate or registered holding companies), however, are subject to a variety of onerous restrictions regarding their organizational structure, financing arrangements, affiliate transactions, and the lines of business they can enter. The SEC and FERC typically play a joint role with regard to cost allocation and intracompany transactions for multistate holding companies. There are only nine registered electric utility holding companies subject to PUHCA regulation. They account for roughly 15 percent of the nation's electric generating capacity. They are primarily descendants of pre-PUHCA holding companies that were able to satisfy PUHCA's system integration requirements.

Truly unintegrated wholesale generating companies owning and operating power plants built to serve the needs of independent distribution utilities were virtually nonexistent before the mid-1980s. Neither state nor federal regulatory policies have traditionally contemplated, let alone encouraged, their development until recently.

The PURPA Revolution

In November 1978 Congress enacted the Public Utility Regulatory Policy Act (PURPA). Among other things, PURPA requires utilities to purchase power from qualifying cogeneration and small power production facilities (referred to generally as "qualifying generation facilities") and to provide them with supplemental and backup service at "nondiscriminatory" rates. PURPA exempted qualifying generation facilities from PUHCA and directed FERC to issue rules defining the specific criteria an independent supplier had to meet to be a qualifying generation facility and rules specifying the methods for determining rates at which utilities would be obligated to purchase power from them and to provide backup and supplemental services to them.

The Public Utility Regulatory Policy Act requires utilities to purchase power from qualifying cogeneration and small power production facilities and to provide them with supplemental and backup service at "nondiscriminatory" rates.

In 1980 FERC issued rules specifying how the relevant prices were to be determined. The general principle incorporated in the 1980 rules is that the price a utility is obligated to pay a qualifying generation facility should reflect the *costs that the utility avoids* (the "avoided cost principle") by purchasing from an independent supplier compared with the best alternative available to the utility to meet its load. Thus, qualifying generation facility suppliers are not themselves subject to price, profit, or cost-of-service regulation as they would otherwise

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have been if FERC had applied traditional cost-of-service regulatory principles as it had to other wholesale transactions subject to regulation under the Federal Power Act. Given price and nonprice provisions specified in the contracts, the qualifying generation facility's financial performance depends entirely on its ability to control costs and deliver electricity efficiently. FERC largely left it to the states to specify exactly how they would implement this principle.

While the administration of PURPA by the states has not been without some significant problems, the overall experience has been quite favorable. Roughly 45,000 Mw of nonutility generating capacity (5 percent of the nation's generating capacity, equivalent to forty nuclear power plants) is now operating in the United States. Another 40,000 to 60,000 Mw of nonutility generating capacity, including both capacity that satisfies PURPA's restrictions and independent power producers' capacity that does not, is in various stages of construction and development. Offers made by nonutility generators to individual utilities to supply electricity to them under long-term contracts routinely exceed, by five to ten times, the utility's stated capacity needs. In 1990 additions of nonutility generating capacity exceeded additions of traditional regulated utility generating capacity for the first time. It is possible that nonutility generators can satisfy a large share of the projected 100,000 Mw of new generating capacity the United States will need over the next decade. More than 100 firms have become active as developers, owners, and operators of qualifying generation facilities. Entrants include subsidiaries of electric and gas utilities, manufacturing firms, construction firms, electrical equipment vendors, and independent developers who offer to build generating facilities around the country (and increasingly internationally). Utilities are now expected to look carefully at nonutility generating capacity to meet their incremental generating capacity needs and not simply to assume that they will build or own new generating capacity themselves.

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It is clear that if the price and regulatory conditions are right, third-party suppliers are willing to enter the market to supply electricity to utilities pursuant to long-term contracts that allocate construction costs and operating risks to the sellers rather than to the utilities' customers. Many of these suppliers have been able to supply at a price less than the utility buyer's estimate of its own supply costs. Once operating, cogenerators in particular appear to have excellent availability records. We have also learned that the costs and benefits of encouraging more reliance on third-party independent suppliers depend critically on the regulatory rules and procedures governing the terms and conditions of contracts.

Building on PURPA to Expand Efficiently Competitive Opportunities

Although PURPA was originally passed primarily as an energy conservation initiative, it has served to open the way for competitive entry into the generation and bulk power markets. We can build on the PURPA experience to expand competitive opportunities in generation if we remove regulatory barriers to efficient pricing, procurement, and organizational arrangements for nonutility generators. In what follows I shall refer to two types of nonutility generators: qualifying generation facilities, which are qualifying facilities under PURPA, and independent power producers, which are not qualifying generation facilities and, as a result, are subject to rate regulation under the Federal Power Act.

While the experience with nonutility generators to date is promising, there are still a number of unresolved questions about the future role of competing nonutility generation suppliers and how they can effectively be integrated into the electric power system to provide cheaper power for customers. How can utilities best solicit, evaluate, and contract for power from third parties? How can utility-owned and third-party nonutility generators be effectively compared and integrated from a planning and operating perspective in a way that takes account of differences in the allocation of risks associated with nonutility and utility-owned generating capacity? Can efficient and credible long-term contractual arrangements be developed for fully dispatchable generating facilities? What regulatory barriers to the entry of efficient suppliers of bulk power services exist and how can they best be removed?

The fact that there are still issues to be resolved does not imply that we should not move forward to remove regulatory barriers to the expansion of competitive generation markets. The traditional system has proven to be less than perfect, and the limited experience with independent suppliers, when a suitable regulatory environment is established, has yielded promising results. Even if we make some mistakes on the margin, they need not be fatal and are potentially reversible. We can build on what we have learned from the PURPA experience to move forward to remove barriers to competing nonutility generation suppliers and to develop mechanisms to integrate those suppliers effectively into the system.

Removing State Regulatory Barriers

Although the debate in Washington about the evolution of competition in the electric power industry has focused on reforms to PUHCA and the Federal Power Act, the evolution of competitive generation markets depends much more on what happens at the state level. Reforms to PUHCA and the Federal Power Act, to which I shall turn presently, enhance competitive *opportunities*. But barring a major preemption of state regulatory authority over retail distribution franchise laws and state retail rate regulation, which I believe is very unlikely, in most cases (some multistate utilities are exceptions) it will be up to the states to ensure that the utilities subject to their jurisdiction take advantage of those opportunities as they seek to meet their obligations to serve retail distribution customers economically and reliably.

To expand and exploit competitive opportunities three kinds of changes must be made in the state regulatory environment. First, states must implement rules that require utilities to adopt good competitive generation procurement programs that carefully evaluate all reasonable competitive alternatives by considering pricing provisions, risk allocations, project viability, and reliability. Second, states must adopt competitive generation procurement programs that allow all supply sources,

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qualifying generation facilities, independent power producers, and utility-owned capacity to compete on an equivalent basis to supply a purchasing utility's incremental supply needs. Limiting competitive supply opportunities to qualifying generation facilities is inefficient and anticompetitive. Third, states must replace traditional accounting cost-of-service retail rate regulation, as it relates to the costs of new generating capacity, with market-based incentive regulation mechanisms that encourage purchasing utilities to search out and contract for the best sources of generation without regard to ownership.

Competitive Bidding and Negotiation Systems. As a consequence of PURPA, the states had to develop regulations to govern utilities' acquisitions of generating capacity and energy from qualifying generation facilities. The states have taken two fundamentally different approaches to regulating this procurement. Initially, most states took a price regulation approach to procurement. Basically, they required utilities to make available to all qualifying generation facilities both short- and long-term "standard contracts" or tariffs with commission-approved uniform price and nonprice terms and conditions. This approach proved to be costly and inefficient. It was very difficult to estimate the "right" market-clearing standard contract terms and conditions that were relevant to generating facilities with very different economic and reliability characteristics. This approach was also not sufficiently sensitive to uncertainties about the supply of qualifying generation facilities' capacity and energy and responded too slowly to unanticipated changes in supply and demand conditions. States that relied on the price regulation approach generally ended up forcing utilities to contract for excessive capacity at exorbitant prices. This harmed ultimate customers because the regulatory process rolled those excessive costs into retail electricity prices.

With the approval of their state regulators, most utilities seeking additional generating capacity have rejected the price regulation approach in favor of a competitive bidding or competitive negotiation approach to procuring power from qualifying generation facilities. Under this approach utilities identify their incremental generating capacity needs by using conventional planning criteria and then issue a request for proposals for some or all these needs. Qualifying generation facilities and in some cases other types of suppliers are then free to make their best offers to satisfy a portion of the needed capacity. Rather than try to determine in advance the appropriate market-clearing price and nonprice terms and conditions of standard contracts, utilities and their regulators agree on capacity needs and evaluation criteria and then let the market determine the most attractive supply opportunities available.

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As of mid-1991 over fifty utilities (investor-owned, publicly owned, and cooperative) have issued at least one request for proposals for generating capacity from qualifying generation facilities (and increasingly other sources as well). A few utilities have now gone through two or more rounds of bidding, evaluation, and selection. About twenty states either have established a bidding rule or allow utilities voluntarily to adopt a competitive bidding system to satisfy their obligations under PURPA. Roughly ten additional states are now considering adopting a bidding rule. Only two states have rejected the use of bidding, but roughly eighteen states have done nothing on the competitive procurement front.

The results to date from the bidding programs that have been adopted are quite promising. As noted earlier, offers made in response to requests for proposals typically amount to five to ten times the amount of capacity that the utility is seeking to purchase. A significant fraction of the offers have prices that are lower than the utility's estimates of what it would cost to build and operate the capacity itself. Although gas-fired capacity predominates, a diverse set of generation projects in terms of size, operating characteristics, and fuels have been offered to utilities for sale under long-term contracts. The incentive contracts negotiated between the utility and the qualifying generation facilities typically allocate most construction costs and operating performance risks (though not fuel price risks) to the nonutility generation supplier rather than to the utility's customers.

All competitive bidding programs are not the same, however. It is convenient to distinguish between the "self-scoring procurement systems" that rely strictly on numerical weights mechanically to evaluate bids and to specify the provisions of final contracts and "competitive negotiation systems" that offer the purchasing utility more flexibility in evaluating competing supply opportunities and negotiating contracts. The evidence suggests that the competitive negotiation systems are superior in bringing economical project proposals to fruition as operating generating plants and in effectively integrating efficient dispatchable facilities into the purchasing utility's portfolio of generating facilities.

Good competitive procurement programs must carefully account for the complexities associated with project evaluation, selection, completion, and operation. By and large, nonutility generators offer utilities power from facilities that have not yet been constructed under contracts with durations of twenty to thirty years. The projects and the proposed contractual arrangements have many important relevant characteristics related to price and price adjustment provisions, risk allocation arrangements, project viability, and dispatch. Furthermore, the value of a particular project is not independent of the composition of the portfolio of projects selected. Selecting a project from those offered is just the first step on the way to a viable operating power plant. A contract must be negotiated between the utility and the supplier. The supplier must obtain financing, a variety of permits regarding the site and air and water emissions, and fuel supply contracts. It has become clear that good competitive generation procurement programs cannot rely on simply choosing the apparent lowest bidder or on mechanical numerical formulas for evaluating competing offers. Successful bidding and evaluation procedures require giving the purchasing utility flexibility to evaluate competing offers on the basis of all relevant price and nonprice characteristics and to negotiate contractual arrangements that keep costs low and provide good performance incentives to the nonutility generation supplier.

Thus, the first area of reform is for the states to adopt good competitive generation procurement systems. Exactly where on the spectrum between rigid self-scoring and flexible negotiation the procurement mechanism falls depends heavily on the amount of regulatory supervision required to ensure that the utilities look carefully at the options that are likely to be available to them and choose those that would be the most attractive. Other things equal, the less regulatory intervention in the procurement process, the better.

Who Gets to Bid? The competitive bidding systems that exist today were initially developed as an alternative mechanism for utilities to meet their obligations to purchase power from qualifying generation facilities under PURPA. Originally, only qualifying generation facilities could participate in bidding programs. This meant either that qualifying generation facilities meeting PURPA's technology, fuel, and size restrictions got preference for serving a utility's generation requirements or that subtle allocations among qualifying generation facilities' capacity, utility-owned capacity, or purchases from other utilities in the wholesale market were made on the basis of more informal evaluation of costs and reliability. A few state commissions have now either required or permitted utilities to open up the bidding programs to include nonqualifying generation facilities that are wholesale power producers under the Federal Power Act and to put all of their capacity needs up for bids.

Clearly, it makes little theoretical sense to limit competitive power supply procurement to entities that happen to satisfy PURPA's technology, thermal efficiency, or fuel requirements. All this does is shelter qualifying generation facilities from competition and create incentives for potential suppliers of power using standard generating technology to distort their projects so that they can meet FERC's criteria for becoming a qualifying cogenerator. (These are affectionately known as "PURPA machines.") Thus, the second area where state regulatory reform is needed is with regard to the range of suppliers that are eligible to compete to supply a utility's generating capacity needs. It is essential that states and utilities adopt competitive procurement rules that allow "all sources" to compete, regardless of ownership or technological characteristics, on an equivalent basis. (Equivalent does not mean, however, that every supplier must formally compete simultaneously with every other supplier in a formal bidding process.)

Including projects owned by or affiliated with the purchasing utility as potential competitors naturally creates a potential conflict of interest. The easy way out of this situation is simply to preclude distribution utilities from owning an interest in any new generating capacity they need. The easiest solution is not necessarily the best solution, however. There are compelling economic and reliability considerations that would make it extremely unwise to completely prohibit utilities or their affiliates from owning new generating facilities to meet the needs of their native load customers. Existing utilities may be in a position to supply some or all of their generation needs more economically or reliably than third parties. While we are gaining experience with independent power suppliers, and this experience is reasonably promising, it is still quite limited. In particular, we simply have not had the opportunity to observe how well the contractual arrangements governing independent power producers' supply relationships with utilities will operate over long periods of time, how well alternative competitive procurement systems will work, how the system will respond to economic shocks, whether suppliers will in fact be able to live up to their contractual promises, and whether larger dispatchable facilities can be integrated effectively by contract into the system. Thus, we cannot yet conclude definitively that an electric power system built on long-term contracts linking distribution and transmission utilities with thousands of independent power suppliers will lead to the most efficient outcomes.

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Even if power by contract rather than ownership and operation does eventually prove itself to yield equivalent or superior outcomes on average, there are still good reasons not to preclude utilities from owning and operating any additional generating facilities to meet the needs of their retail customers. First, experience in building and operating generating facilities can be very useful to a utility in soliciting and evaluating competing power supply arrangements offered by third parties. Second, the threat that a utility can build to meet its generating needs if sufficiently attractive offers are not made available to it will help to ensure that the procurement process is in fact competitive and leads to both the lowest cost for consumers and an efficient allocation of resources to generation. Third, utilities may be in a good position to identify existing projects that are failing to perform effectively or proposed ownership changes that threaten effective performance. Providing utilities with the option to purchase such projects could benefit consumers. Finally, a utility that cannot build new generating facilities may find it more difficult to attract, train, and retain the highest quality technical personnel to operate *existing* facilities efficiently and effectively to solicit, evaluate, and monitor power supply opportunities provided by third parties.

Incentive Regulation to Minimize Costs. I have argued that utilities should be encouraged to adopt competitive generation procurement procedures and that the competition to satisfy a utility's resource needs should be open to all potential suppliers of generation, including the utility or its affiliates. I have also argued that flexible procurement systems that give the purchasing utility discretion to evaluate and select projects are likely to be much more cost-effective than programs that rely on extensive state regulatory intervention in the solicitation, evaluation, and contracting process. But to do all of this, it is essential that there be regulatory procedures to remove incentives utilities might have to favor their own projects or to fail to evaluate carefully the merits of competing supply opportunities. Traditional cost-of-service regulation dulls and distorts incentives for least-cost supply procurement and operation. A key part of any strategy to expand the competitive generation sector should include changes in traditional state cost-of-service regulation to provide utilities with better incentives. Therefore, it would be desirable to create regulatory rules for the retail ratemaking treatment of costs associated with new power supplies that provide positive incentives for utilities to evaluate all supply options on an equal footing without regard to ownership. Such a regulatory system ideally would make it possible to maximize the flexibility that utilities have to negotiate bilateral contracts with diverse suppliers and to minimize direct regulatory intervention into the structure of the contracts negotiated between utilities and third-party suppliers.

Changes should be made in traditional state cost-of-service regulation to provide utilities with better incentives for least-cost supply procurement and operation.

There are a variety of specific changes in regulatory procedures that would change incentives in the appropriate way. But the fundamental principle associated with any specific regulatory mechanism is the same: the compensation that the utility receives for providing generation services must be fully or partially decoupled from the actual costs the utility incurs. At the extreme, state commissions could develop benchmark prices for new generating capacity and associated energy, based on data from the wholesale generation market, and base utility compensation entirely on those benchmarks. In this way the compensation a utility receives would be completely independent of whether it adds new capacity that it owns or buys from third parties. Under this type of "market yardstick" regulatory mechanism the purchasing utility would have strong incentives to choose the most economical supply sources, regardless of who happened to own a particular generation source.

Generation markets may not yet be robust enough and the resource needs of individual utilities may be too idiosyncratic to rely entirely on simple price benchmarks drawn from market data. In that case it would make sense to adjust traditional cost-of-service compensation arrangements so that they *partially* decouple compensation from actual costs by adopting an incentive regulatory mechanism that forces the utility to bear a profit penalty or receive a profit reward based on the difference between the actual costs the utility incurs and relevant wholesale market price benchmarks.

State commissions have not recognized that getting utilities to look to third parties and to make good procurement decisions requires changes in the regulatory environment that encourage utilities to pursue the most economical supply alternatives. It is about time that such changes are made.

The Unfortunate Tendency toward Central Planning and Taxation by Regulation. Rather than adopt an incentive regulatory mechanism that will allow utility procurement from all types of competing suppliers to proceed smoothly with a minimum of government regulation, several states have moved in the opposite direction. Ironically, the movement toward competitive generation procurement is being overwhelmed by increasing state utility commission intervention in the planning, solicitation, evaluation, and procurement of new supply sources under the banner of something called "integrated resource management." Several states have required utilities to adopt complex and time-consuming integrated resource management processes that go well beyond what is conceivably necessary to ensure that utilities make least-cost procurement decisions. They often require including subsidies for electricity conservation as if conservation were a "supply source" and increasingly require the application of a variety of "adders" and "subtractors" to different types of projects to reflect real or imagined externalities in the evaluation of new resource options.

Integrated resource management is just a fancy name for central planning by state public utility commissions. For reasons that are difficult to understand, these state central planning initiatives are being encouraged by the Bush administration's Department of Energy. Indeed, the secretary of energy has put his personal stamp of approval on these central planning approaches, apparently learning nothing from the experience in Eastern Europe and the former Soviet Union. Such developments are rapidly turning the competitive procurement process into a feeding trough for special interest groups, which are using the "golden goose" of the regulated distribution utility as a tax and subsidy mechanism for their benefit. They are turning the promise of cheaper power from competition into a cruel hoax through which special interests have been able to capture state regulatory agencies so that competitive generation procurement processes are distorted to make electricity as expensive as possible. This must stop if the consumer benefits that lie at the heart of the movement toward competition are to be realized.

Federal Regulatory Barriers

The most important federal regulatory barriers to the expansion of competitive generation markets are regulatory rules governing the pricing of wholesale power under the Federal Power Act and organizational, ownership, and financing restrictions under PUHCA. FERC has gone a long way toward removing Federal Power Act barriers to competitive pricing for nonutility generators. Further progress can be made without new legislation. Organizational and ownership restrictions mandated by PUHCA can only be removed by new legislation, however.

Price Regulation under the Federal Power Act. Ideally, we would like a utility to be able to turn to the most economical supply sources, whether they are qualifying generation facilities, independent power producers that are not qualifying generation facilities, excess capacity and energy available from other integrated electric utilities, or internal utility production. Any wholesale supplier that is not a qualifying generation facility under PURPA, however, is subject to rate regulation under the Federal Power Act rather than under PURPA. While the Federal Power Act does not appear to mandate cost-of-service/rate-of-return regulation, that is the principle that has guided regulation of long-term wholesale power contracts for the past fifty years. As a result, nonutility generators that are not qualifying generation facilities faced the prospect of ex post accounting cost-of-service regulation by FERC. This regulatory pricing approach is inconsistent with the efficient development of competitive power markets.

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To encourage nonqualifying generation facilities to supply unintegrated or partially integrated utilities under contracts with a wide range of risk/reward characteristics, the Federal Power Act's regulations regarding wholesale power contracts must be reformed. In particular, the terms and conditions of contracts governing the sale of power by independent nonqualifying generation facilities will have to be structured in much the same way as are the contracts that govern utility purchases from qualifying generation facilities. That is, the prices at which those entities sell power to utilities cannot be based on traditional cost-of-service principles, as they would be under traditional FERC ratemaking procedures.

Over the past two or three years FERC has made very significant progress in developing "market-based" pricing rules for nonutility generators that are subject to regulation under the Federal Power Act through a series of rulings on applications by independent power producers for "market-based rates." Pursuant to those rulings, FERC will approve wholesale contracts that do not satisfy traditional cost-of-service criteria in situations where it is unlikely that the seller is in a position to charge prices that are excessive either by exercising conventional market power or by exploiting imperfections in the regulatory process. FERC has also been concerned that independent power producers that are utility affiliates not be able to distort the generation market through cross subsidization of unregulated (nonutility generator) affiliates by improperly allocating nonutility-generator-related costs to the utility affiliate and its customers. Several criteria can be gleaned from FERC's decisions in this area.

It is appropriate to balance the imperfections of markets against the imperfections of regulation to find policies that improve the allocation of resources even if the results are not completely identical to what would emerge in a hypothetical, perfectly competitive market.

- Nonutility generators that are unaffiliated with either the purchasing utility or any other utility can readily get market-based rates approved as long as the buyer can show that it has used a procurement system that makes a reasonable effort to identify and evaluate competitive alternatives and a "sufficient" number of competing supply options are available to it.

- Nonutility generators that are affiliated with a utility but make sales to another utility remote from the location of their utility affiliate can get essentially the same treatment by demonstrating that they have a cost-accounting system in place that precludes cross subsidization of the unregulated nonutility generator subsidiary by the regulated utility subsidiary.

- Nonutility generators that are affiliated with a utility but make sales to another proximate utility must meet all of the above criteria *and* must show that they have not used their control over transmission to restrict competition. As a practical matter, FERC requires such utilities to file acceptable "open access" transmission policies to obtain approval for market-based rates.

- A utility can get market-based pricing treatment for sales made to an *affiliate* only if it can meet stringent criteria demonstrating that it has not charged its affiliate excessive prices. The specific criteria are still evolving, but it appears that market-based pricing will be approved only if the utility can demonstrate that the price meets or beats arm's-length market benchmarks or that other unaffiliated buyers enter into similar contracts with the same supplier.

- FERC has also allowed nonutility generators to cost-justify their contracts by using what can best be described as an expected cost criterion using the terms and conditions of the power supply contracts and information on the nonutility generator's expected construction and operating costs. Although FERC has not formally recognized it, this approach creates a cost-based incentive regulation system that is far superior to traditional ex post accounting cost-of-service regulation. This approach should prove to be especially useful for dealing with affiliate transactions or sales by a utility or utility affiliate to proximate utilities where market power concerns have not been resolved.

FERC has made quite a bit of progress defining ratemaking rules that largely eliminate Federal Power Act regulation as a barrier to entry of independent power producers. It is time for FERC to codify the policies enunciated in individual cases into a set of rules and filing requirements to remove residual uncertainties regarding its policies toward independent power producers. FERC needs to develop clearer rules to govern affiliate transactions and to better harmonize state and federal regulatory responsibilities in this area. FERC has also been excessively cautious about extending market-based pricing to more conventional wholesale transactions between utilities in situations where sellers are unlikely to have significant market power. For reasons that are a complete mystery, FERC has retreated from its very productive efforts in the early 1980s to expand market-based pricing of wholesale power generally. This retreat appears to be based on the erroneous assumption that the mere ownership of transmission lines confers market power in relevant bulk power markets. Rather than assume that all utilities have market power, FERC should apply accepted antitrust principles to measure market power. Furthermore, FERC must recognize that definitive proof of a complete absence of market power is the wrong criterion for evaluating flexible pricing proposals. Instead, it is appropriate to balance the imperfections of markets against the imperfections of regulation to find policies that improve the allocation of resources even if the results are not completely identical to what would emerge in a hypothetical, perfectly competitive market.

Reforming the Public Utility Holding Company Act. The Public Utility Holding Company Act of 1935 creates another federal regulatory barrier to the development of an independent power producers' segment of wholesale power markets. PUHCA became law at the same time as the Federal Power Act. It was passed primarily in response to a variety of regulatory and financial abuses by public utility holding companies that occurred in the 1920s and 1930s.

The provisions of PUHCA are complex, and I shall provide only a cursory summary of its most relevant provisions. Under PUHCA any corporation or trust owning 10 percent or more of the stock of a gas or electric company must register as a public utility holding company under the act and become subject to regulation by the Securities and Exchange Commission. Exemptions have been granted to holding companies that are primarily intrastate in character, holding companies that are predominantly operating public utility companies, and holding companies that are primarily nonutility companies and only incidentally public utility holding companies. PURPA provides an exemption for qualifying generation facility subsidiaries as well.

If a utility holding company cannot obtain an exemption, it becomes subject to a variety of regulatory restrictions administered by the SEC. For example, the utility subsidiaries of an interstate public utility holding company must operate as a single, integrated system (that is, the holding company could not own independent power producers remote from its retail service territories). In addition, the SEC regulates transfers of goods and services between subsidiaries (for example, a fuel or service subsidiary). The SEC generally requires that such transfers be made "at cost." Another restriction limits the holding company to engaging only in activities that are directly related to the provision of electricity. In addition, a public utility holding company cannot own both electric and gas utilities (that is, a gas utility holding company cannot own independent power producers). The SEC must approve all mergers and acquisitions and grants such approval only if the acquisition will tend towards the economic and efficient development of an integrated public utility system. Finally, the SEC must approve the issuance of securities by holding company subsidiaries and regulate the financial structure of the holding company.

PUHCA impedes the entry of many independent power producers as potentially efficient suppliers of generating capacity. The system integration provisions could keep existing registered holding companies from competing to supply nonqualifying facility generating capacity in areas of the country remote from their service territories. Some of those companies have demonstrated superior performance in building and operating generating facilities. They should be encouraged to offer their expertise more widely than in their own service areas. Public utilities that are exempt holding companies under PUHCA (accounting for almost half of U.S. generating capacity) due to the intrastate character of their utility operations, would lose their exemptions if they formed independent power producing subsidiaries that owned generating facilities to provide wholesale power to utilities in a state other than the one in which they currently operate. Once they became registered holding companies, they would be precluded from owning generating facilities that are not part of a single, integrated system, so that they would have to spin off the independent power producing subsidiary that made them subject to registration under the act in the first place (a real catch-22). Nonutilities that are holding companies or that sought to create a wholesale generation subsidiary within a holding company framework

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would become public utility holding companies and might have to spin off their other businesses to conform with the act. Overall, PUHCA represents a formidable, but not insurmountable, constraint on the entry of independent power producers because it requires relying on complex ownership arrangements to avoid triggering the regulatory requirements of the act. Independent power producers' projects have been able to get around the restrictions in PUHCA by relying on complex financial arrangements that limit ownership and control. These arrangements increase costs by constraining the ability of independent power producers' owners to rely on the most efficient ownership, organizational, and financial arrangements.

There is no reason why PUHCA cannot be amended to remove unnecessary barriers to the efficient entry of independent power producers without compromising any necessary regulatory protections that PUHCA still provides. For independent power producers that do not have any gas or electric utility subsidiaries, the obvious solution is simply to exempt such entities from PUHCA. Since such entities have no utility affiliates that would raise concerns about cross subsidization or affiliate transactions, there is no reason for them to be subject to PUHCA at all. Other state and federal securities laws can adequately protect the public from the kinds of fraudulent financial arrangements that partially motivated PUHCA in 1935. The self-interest of utility buyers, combined with state and federal regulatory supervision of generation procurement, can continue to protect utility customers from entering into contracts for power from independent power producers' projects that are not financially sound.

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Removing PUHCA's barriers for independent power producer subsidiaries that are affiliates of utilities at least superficially raises potentially more significant issues related to cross subsidization, abusive affiliate transactions, and the financial stability of holding company structures. But state utility regulations, state laws governing holding companies, and the Federal Power Act provide more than adequate protection to guard against such abuses. FERC has already demonstrated that it will use its authority under the Federal Power Act carefully to scrutinize affiliate transactions and cost allocations between regulated and unregulated affiliates. In the case of exempt holding companies that have utility affiliates primarily in a single state, state laws exist or can be passed to provide for the regulation of cost allocations, financing arrangements, and procurement policies for both the holding company and its utility subsidiaries. All that needs to be done here is to amend PUHCA so that exempt holding companies do not become subject to PUHCA merely because they have a controlling interest in one or more independent power producers outside the state where the utility subsidiary does business. Multistate holding companies can already set up independent power producer subsidiaries and sell power to third parties subject to the regulatory scrutiny of the SEC and FERC. Providing reasonable opportunities for them to compete simply requires relaxing the system integration requirements so that multistate holding companies can have independent power producer subsidiaries remote from their service areas and offering more financing flexibility so that they can compete with other independent power producers.

Thus, "the PUHCA problem" can be solved with relatively simple legislation with the following provisions. Entities that do not have any utility affiliates would simply be exempt from PUHCA. Exempt utility holding companies would not trigger PUHCA regulation merely as a consequence of having ownership interests in independent power producers. State and FERC regulations of costs and rates would apply as they do now. Multistate utilities would not trigger the system integration requirements of PUHCA merely as a consequence of owning independent power producers remote from their service areas. They would also be given additional financial flexibility for independent power producer projects with continuing SEC and FERC supervision of financing arrangements and corporate structures, cost allocation, and rates.

Several bills have been introduced in Congress to amend PUHCA along these lines. While the proposed amendments are controversial, as this is written, broad support appears to be emerging for some type of PUHCA reform. The primary issue is how much additional electricity-related legislation will be appended to the modest PUHCA reforms that are actually necessary to remove unnecessary barriers to competition. Proponents of transmission access and pricing reforms have tied PUHCA reform to new transmission legislation. The debate about PUHCA reform has also triggered debates about a variety of other electricity issues including state versus federal regulatory jurisdiction, regional regulation, and least-cost planning. None of these additional reform proposals is necessary for the kind of surgical PUHCA reform that I have outlined to help to promote competition in generation. Some of the proposed reforms may be desirable in their own right. Others are not. It would be a shame, however, to hold PUHCA reform hostage to other electricity policy issues that can be, and probably should be, addressed separately.

Conclusions

A thriving competitive market for generating service provided by generating companies that are not subject to traditional price and entry regulation has emerged in the United States. Increased competitive opportunities in generation promise to reduce electricity costs and foster reliance on a more diverse set of generating alternatives. The further development of this market requires significant regulatory changes at the state level. It also requires continuing the process of reforming federal rate regulation of wholesale power transactions. Legislation is needed to remove barriers to competition created by PUHCA. Absent a complete set of regulatory and statutory reforms that clearly recognize a state and federal policy commitment to promoting competition where it works well compared with regulation, the evolution of competitive generation markets will be unnecesarily constrained to the disadvantage of consumers and the economy.

Selected Readings

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