ELECTRIFYING CHANGE:

STRATEGIES FOR STRUCTURAL REFORM IN THE ELECTRIC INDUSTRY

Prepared by the
Emerging Operational Issues Committee
of the
Electric Generation Association (EGA)

EGA is a national trade association representing independent power producers (IPPs) and suppliers of goods and services to the competitive wholesale electric generation industry. In every year since 1990, IPPs have accounted for approximately 50 percent or more of all new electric generation capacity brought on line in the United States. The philosophy of EGA member companies is that electric utilities are their customers. EGA's members provide their utility customers, and hence the general public, with safe, reliable, low-cost, and clean electricity.

EGA's Emerging Operational Issues Committee identifies and examines emerging issues affecting the ability of IPPs to provide efficient wholesale power service, including issues related to industry structure reform.

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EXECUTIVE SUMMARY

The Electric Generation Association (EGA) is a national trade association representing independent power producers (IPPs) and suppliers of goods and services to the competitive wholesale electric generation industry. EGA contributes this paper to the debate concerning the current restructuring taking place in the electric industry. Electricity is vital to nearly all sectors of the United States economy, and the evolution of regulatory policy will therefore have an important effect on the nation's economic competitiveness.

The role of independent power in the U.S. electric industry expanded dramatically within the past decade. Competition in wholesale power markets resulted primarily from significant changes in the economics of generation, favoring smaller, shorter lead-time projects than were commonly built by utilities in the 1970s. As of year-end 1993, independent power is approaching ten percent of the nation's installed generating base. Throughout the 1990s, IPPs have accounted for a majority of new generating capacity being added to the nation's electric grid each year.

Changes in the economics of generation have been the driving force behind a series of legislative and regulatory reforms aimed at removing impediments to a more competitive power market. The modern IPP industry effectively came into existence with the passage of the Public Utility Regulatory Policies Act of 1978 ("PURPA"). PURPA represented the first step of structural reform to the vertically-integrated utility industry. It provided, for the first time in the modern era, an alternative to the traditional rate-base, rate-of-return formula for private generation investments. The process of reform was carried forward in the states through a variety of experimental and innovative approaches to implementing PURPA. More recently, many states have converged on the view that new sources of capacity should be selected through some type of competitive procurement process.

Federal legislative reform took a significant step forward with the passage of the Energy Policy Act of 1992 ("EPAct"). This statute explicitly adopts the principle of competition at the wholesale level of generation as the new cornerstone of U.S. electricity policy. This Act represents the most fundamental federal policy development in this area in almost 60 years. The implementation of EPAct will take place over the next several years, and its implications are not yet fully apparent in state-level regulation. Thus, the process of structural reform in the electricity market is incomplete and ongoing.

The role of independent power in the U.S. electric industry expanded dramatically within the past decade.

The electric industry is caught in a difficult transition. Although EPAct endorses competition in wholesale power markets, strong resistance to independent power remains, largely within the investor-owned utility industry. Utilities often criticize independent power on the basis of defects in the implementation of PURPA at its early stages. Although such defects have largely been cured with experience, nevertheless, many utilities view independent power not as a source of cost-effective supply but as a source of competition, and are anxious about incursions into their traditional markets. Some utilities have adopted aggressive regulatory strategies to weaken the position of IPPs on their systems. Power procurement procedures often reflect an apparent bias against independent power, even when it is less costly and subjects ratepayers to less risk than utility-constructed capacity.

The result is a heightened contentiousness and proliferating litigation in the power planning and procurement arena which, if unchecked, will delay and diminish the benefits of vigorous competition to the general public. Decisions with an important bearing on the nation's economic and environmental future are being deferred. Meanwhile, on the other side of the electric meter, large industrial customers are acting on their frustration with the high cost of electric service. Many are beginning to pursue options for obtaining electric service that would bypass the conventional utility rate structure, threatening to unravel the concept of the franchise system.

The solution to these problems requires a rethinking of fundamentals. The difficulty and cost of restructuring is likely to be minimized to the extent that it is guided by consistent principles and not simply a random, balkanized sequence of regulatory decisions and market events. Restructuring will proceed in a more orderly fashion, in other words, if it is guided by a shared vision of the future. This will require that industry stakeholders forge a consensus around certain basic issues. It is impossible, of course, to project the exact form the industry will assume. The mere fact that it will be open to competition suggests that the industry will be in continuous evolution. This vision must be based on broad outlines rather than details so as to accommodate a broad range of directions in which the industry might evolve. At a minimum, in EGA's view, this vision should include the following elements:

- It must reflect the realities of market-based competition in the generation sector within the larger framework of regulation.
- It must be open to a rich variety of service options at competitive cost.
- It should be based on an appropriate allocation of risks and incentives for all.

The current debate, in short, is an effort to revise the "regulatory bargain." To be successful, this process of redefinition must reflect a more discerning approach to the current realities of each segment of the industry than the existing framework, which has survived largely intact from the 1930s.

Many of the conflicts in planning and procurement that are experienced in today's electric industry appear to arise from the conjunction of two factors: the application of cost-of-service principles to utility-constructed generation facilities, and the implicit acceptance of vertical integration of utility operations. The interplay of these factors makes genuine competition among all resource options problematic. One of the most promising and widely-discussed approaches to reform currently under discussion in the industry would entail the functional unbundling of the generation sector. While this term suggests a variety of possible approaches, all would entail the separation of generation from core utility services, at least for cost accounting and ratemaking purposes, if not also from the standpoint of corporate structure and ownership. The term "core utility services" in this redefined context includes services such as transmission and distribution, which would retain the character of a natural monopoly and continue to warrant some form of traditional regulation.

The development of a truly competitive generation market that supplies power to utilities as providers of transmission, distribution and other services, holds the promise of improved efficiency, lower costs to ratepayers, a reduced need for regulatory intervention and oversight and, accordingly, a reduced burden on regulators themselves. Many utilities have begun to restructure their internal operations into wholesale and retail groups, or along functional lines, to promote their viability in the marketplace and in the expectation that this type of regulatory structure will evolve. It is now common in overseas power markets, and EGA expects this type of reform to become more prevalent in the United States in the coming years.

As competition has taken hold in the generation sector, the role of state regulators has evolved, and will continue to evolve. Economic regulation will continue to encompass general oversight of utility assets. In the future, however, a progressively more important component of regulators' responsibilities will be the oversight of competitive market conditions and processes. Through an orderly and progressive separation of generating assets from core utility assets, and the oversight of the development of rates for each distinct component of utility service, regulators will be better able to foster conditions in which all generators are subject to a common discipline. An environment in which all generators abide by a common set of principles will better ensure optimum long-term investment and short-term production decisions. It also will enable utilities and other market participants to identify, plan for and properly price the variety of creative companion services that is expected to emerge as competition unfolds.

Restructuring will proceed in a more orderly fashion ... if it is guided by a shared vision of the future.

The regulatory bargain cannot be updated to respond to modern competitive realities without short-term consequences, potentially benefiting some companies and customers while disadvantaging others. Although the long-term efficiency benefits promised by a transition to a more fully competitive generation sector are compelling, behaviors in the regulatory arena are too often driven by fears of the short-run consequences of moving in this direction. It is essential to acknowledge such concerns and deal equitably with the balance of interests between utilities and other stakeholders. While the pressure for procompetitive reform is significant, EGA believes that certain constraints must be observed in the process:

- **overall societal costs should be minimized** in the transition toward a more fully competitive generation industry and, if possible, should not exceed anticipated costs under the status quo;

- financial burdens should be broadly shared; and

- the reliability of utility service must be safeguarded.

It is time for stakeholders in the electric industry to come to a common understanding of the forces that are changing the industry, and to develop a new regulatory framework that can accommodate those forces. Participants in this process must not take for granted — indeed, should explicitly challenge — the traditional regulatory framework. To promote efficient decisions, the new framework must reflect the current realities of each segment of the industry. To be politically stable in the long run, it must synchronize ratepayer and shareholder interests. The need for such a consensus-building effort is compelling in light of widespread customer dissatisfaction with the status quo. EGA offers this paper in the hope that it will move the consensus-building process forward.

INTRODUCTION

The Electric Generation Association (EGA) is a national trade association representing independent power producers as well as suppliers of goods and services to the competitive wholesale electric generation industry.[1] EGA seeks to advance the perspective of competitive wholesale power generators in an industry undergoing rapid change. Although these generators are commonly referred to as independent power producers or IPPs, the sector encompasses both non-utilities as well as utility-affiliated entities. The common feature of its participants is that they provide electric energy and capacity at wholesale rates pursuant to contracts negotiated within the discipline of the marketplace, rather than according to the traditional rate-base model of regulation.

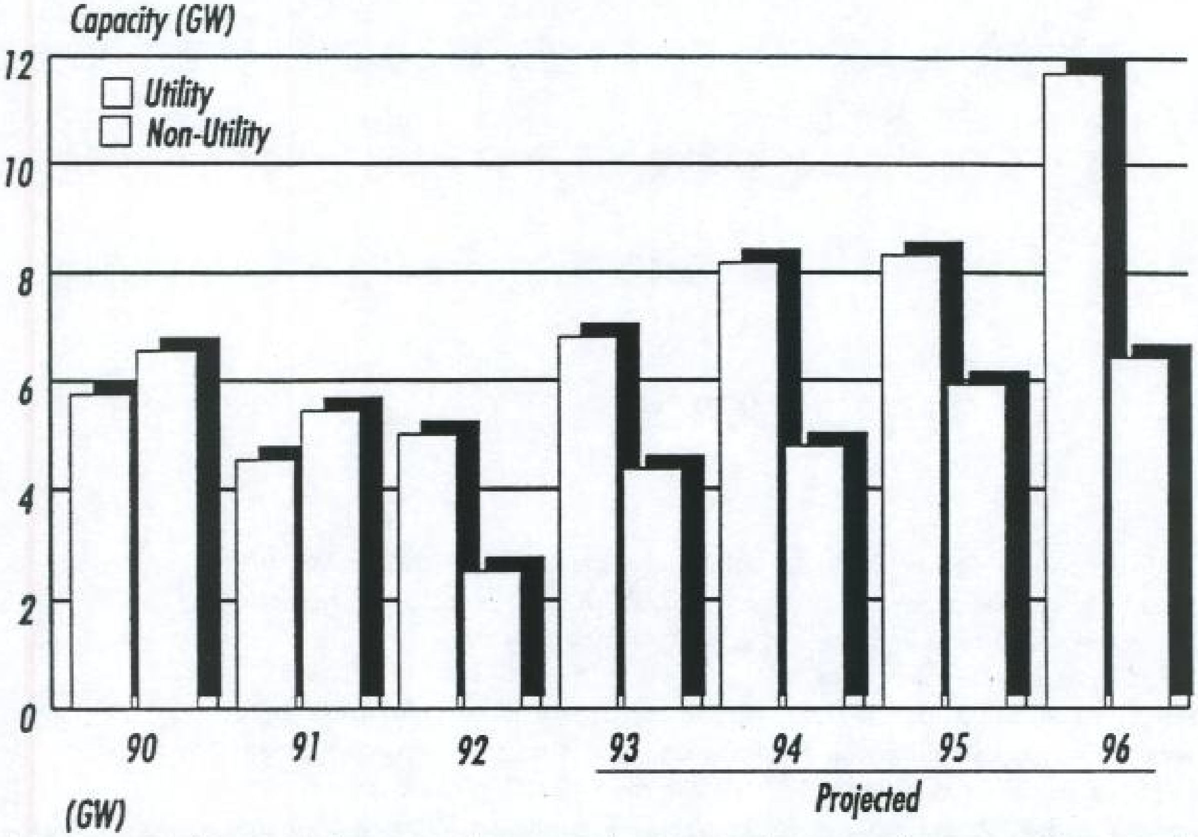
This white paper is the work product of EGA's Emerging Operational Issues Committee. This Committee is charged with identifying and examining issues affecting the ability of IPPs to provide efficient wholesale power service to utilities.

EGA's objective in issuing this paper is to help crystallize a series of issues at a pivotal point in the evolution of the electricity marketplace. The singular importance of the electric power sector in the United States economy is illustrated by its size and relationship to other types of economic activity. Policies governing generation investment and operating decisions thus have a significant bearing on the nation's productivity and global competitiveness, as well as upon environmental quality.

For most of its history, the electric power industry has been subject to perhaps more pervasive government control than any other major industry in the U.S. economy. The current reform process is being forced by

1 *The members of EGA's Board of Directors include the following companies: CMS Generation Company; CNG Energy Company; Cogentrix, Inc.; Constellation Energy, Inc.; CSW Energy, Inc.; Dickstein, Shapiro & Morin; Dominion Resources, Inc.; Duke Energy; Energy Initiatives, Inc.; HYDRA-CO Enterprises, Inc.; J. Makowski Associates, Inc.; LG&E Power Inc.; Mission Energy Company; NRG Energy, Inc.; Southern Electric International; Tenneco Power Generation Company; and U.S. Generating Company.*

NEW ADDITIONS IN UTILITY AND NON-UTILITY CAPACITY 1990-1996



(GW)

	90	91	92	93	94	95	96
Non-Utility	5.746	4.538	5.000	6.809	8.180	8.328	11.711
Utility	6.566	5.434	2.516	4.361	4.783	5.925	6.428

Source: Utility Data Institute, # UDI-032-93 (February 1993).

rapidly changing circumstances in the marketplace, the inexorable march of competition, and the demand for a variety of new services. For several years there has been lively debate on how regulation should adapt. However, the actual pace of regulatory reform, which typically involves a lengthy deliberative process, has lagged behind the pace of change in the industry itself. In some parts of the country, large industrial customers, unwilling to accept the cost allocations of traditional utility ratemaking, are pursuing a variety of alternative arrangements that bypass the conventional rate structure. A debate is intensifying on the issue of how best to promote competition in order to ensure that the electric power industry can continue to meet its historic mandate to provide reliable, clean and economical power at equitable rate levels for all customers.

In our market-oriented economy, the prevalent cost-of-service framework of utility regulation is an exception to the rule. This system, which awards profits to utilities in proportion to the size of their rate base, has the potential for resulting in reduced efficiency and skewed incentives. Yet it was adopted as a matter of pragmatic necessity. In its early stages of development, the industry clearly bore the characteristics of a natural monopoly. Within this framework, the vertical integration of utility operations across functional lines, including generation, transmission and distribution, has come to be an accepted fact.

Conditions in the industry have undergone a dramatic change in recent decades, bringing into question the basis for this form of regulation. As the electric industry has matured, there has been a dramatic increase in the role of independent power. Competition in wholesale power markets has resulted from significant changes in the economics of generation, favoring smaller, shorter lead-time projects than were commonly built by utilities in the 1970s. The introduction of competition has sparked a wave of innovation. Attracted by profit opportunities and driven by competition, independents have been in the forefront in developing generating projects with improved efficiency, cost and environmental characteristics. As competitive conditions strengthened, power contracting practices became highly sophisticated. In contrast to the traditional cost-plus approach, detailed and explicit contracts provide a means of identifying and allocating risks and benefits efficiently among suppliers, utilities and customers so as to reduce the overall cost of power to the ultimate ratepayers.

THE ELECTRIC INDUSTRY: KEY FORCE IN THE U.S. ECONOMY

- The total value of net utility plants, one of the most capital-intensive industries in the nation, is $518.8 billion, or almost $2,000 for every citizen in the United States.[2]

- Annual revenues from the sale of electric power to ultimate consumers are approximately $200 billion per year, or approximately three percent of the nation's entire GNP.[3]

- An ever-increasing portion of end-use energy consumption in the United States is in the form of electricity. In 1970, electricity comprised 25% of end-use energy consumption; this figure rose to 36% by 1989 and has been projected to reach 46% by 2010.[4]

- Choices regarding electricity production also have a significant impact on our natural environment. While electric output constitutes three percent of GNP, it accounts for two thirds of the nation's sulfur dioxide (SO_2) emissions, as well as one third of nitrous oxide (NO_x) emissions.[5]

While driven by market forces, the development of the independent power industry has been facilitated by a series of landmark legislative and regulatory actions. These include the Public Utility Regulatory Policies Act of 1978 ("PURPA"), competitive procurement policies implemented by numerous state commissions, and, most recently, the Energy Policy Act of 1992 ("EPAct"). The success of the IPP industry calls into question the benefits of

2. *Statistics abstracted from various U.S. Energy Information Administration annual reports.*
3. *Ibid.*
4. *Ibid.*
5. *Natural Resources Defense Council, "The Great 'Retail Wheeling' Illusion —And More Productive Energy Futures," Ralph Cavanagh, October 1993, p. 4.*

vertical integration as well as the suitability of the traditional cost-of-service regulatory framework to utility investments in generating facilities.

Experience shows that, once unleashed, the progress of competition is irreversible; efforts to thwart it will ultimately fail. The record of the past two decades amply demonstrates that a workable competitive wholesale power industry can exist. The passage of EPAct, and the intensity of competition in regions that have experienced capacity needs, have called into question the continued suitability of the traditional monopoly model of rate-base regulation in the generation sector. Within our economic system, direct regulation of prices is a second-best approach to disciplining markets, suitable only in situations prone to market failure. It has been an article of faith throughout our nation's history that, if it is achievable, customers are best served by a well-structured system of open competition. Such a system yields allocative, productive as well as administrative efficiencies which often are sacrificed when the government intervenes.

The electric industry has entered a period of restructuring. EPAct's broad legislative mandate to embrace competition is clear; it is universally recognized that the traditional industry structure, featuring vertically-integrated utilities operating solely under strict cost-of-service regulation within monopoly franchise territories, is outmoded. Nevertheless, because the rate-base system of regulation is so firmly entrenched, it will be difficult to unwind this structure without disruptive effects. Regulatory reform has proceeded largely through incremental measures and case-by-case decision making. The result is an unstable situation of confusion and heightened financial risk for IPPs, the utilities, and their ratepayers.

Unguided market forces may lead to widespread customer defections, destructive forms of competition and higher costs to society. Therefore, EGA believes it is useful for all stakeholders to come to a more precise understanding of the forces driving the current transformation of the industry. A common understanding of these forces will enable the industry to defuse the contentiousness of the current situation which, if unresolved, will deprive consumers of the full benefits of competition.

THE RATIONALE FOR REGULATION: A BRIEF HISTORY

The American system of electric utility regulation, while accepted as a given among those close to the industry, represents a salient exception to a general rule in our nation's economy. In other economic sectors, a basic tenet holds that markets should be open to all producers, and that open competition should determine which goods are produced, by whom, and at what price. The economic regulation of utilities on cost-of-service principles is a system originally born not out of theoretical preference but as a matter of pragmatic necessity because of a peculiar set of conditions.

The rationale for monopoly regulation

Cost-of-service regulation originated in response to an urgent set of problems. From its inception until the early 20th Century, the electric industry developed in an unruly fashion. While electric service expanded and technology developed rapidly, the process entailed a good deal of waste and abuse. Not unlike the railroads of the late 19th Century, and for similar reasons, the electric industry was faced with the specter of expensive and unnecessary duplication of facilities. It became apparent that each of the principal functions of the industry, including generation, transmission and distribution, based upon the technology of the era, were characterized by declining costs and fit the "natural monopoly" model. That is, if left unsupervised, the electric industry would tend toward excessive concentration, with the possibility that one provider would dominate the market and provide an inadequate level of service at excessive prices so as to maximize profits. However, a single provider operating with an exclusive franchise and assured revenues under government supervision would have sufficient incentive to plan for facilities and services necessary to deliver electric service to all customers in a given area.

1900s - 1930s: The origins and development of the franchise system

This recognition led to the adoption of the monopoly franchise system. Under this system, in exchange for exclusive franchise rights, utilities were placed under an obligation to serve all customers in their territory, and constrained by rates established so as to afford an opportunity to recover their prudent operating costs plus a reasonable return on invested capital. At first a matter of local control, utility regulatory oversight was later shifted to state bodies; these public utility commissions were given authority by delegation from their state legislatures. Between the turn of the century and the early 1930s, virtually every state adopted this system.

Until the early 1970s, the electric utility industry throughout the nation enjoyed steady expansion, financial strength and stable or declining rates.

The last pieces of the regulatory framework governing utilities in the modern era fell into place with the enactment of the "New Deal"-era legislation, including the Public Utility Holding Company Act of 1935 ("PUHCA"), which governed several aspects of corporate structure, and amendments to the Federal Power Act the same year, which governed the increasingly important interstate trade in electricity as isolated utilities became progressively more interconnected. Together with the regulatory oversight of retail transactions provided by state commissions, these statutes reflected an acceptance of vertical integration as a fact of life in the utility industry, and aimed at providing a "seamless web" of consumer protection through supervision of the entire chain of transactions within this structure.

1930s - 1960s: A period of tranquillity

Although the utility industry continued to pose unique challenges to government policymakers, nevertheless, these issues seemed to be satisfactorily addressed within the classic regulatory framework throughout the mid-20th Century. Rate-base regulation, despite the fact that it created inefficient incentives and required active policing by utility commissions, produced acceptable results for utilities as well as regulators. Serious consideration was not given to imposing the discipline of market-based mechanisms.

Until the early 1970s, the electric utility industry throughout the nation enjoyed steady expansion, financial strength and stable or declining rates. To some extent, this happy confluence of circumstances may be attributable to effective regulation. However, in retrospect, industry historians note that several factors unrelated to the form of regulation contributed to the environment of stability. These included stable fuel costs, steady technological improvement, and the continuing realization of economies of scale in the construction of generating units. These exogenous factors made the monopoly franchise system appear to be a "win-win" situation for utilities and their customers alike, and mitigated pressure to explore alternatives.

The tumultuous 1970s: Breakdown of the natural monopoly framework

Starting in the early 1970s, however, the traditional stability of the electric utility industry began to break down. Beginning with the Arab Oil Embargo of 1973-74, world energy prices became increasingly volatile. With inflation and interest costs on the rise, construction financing costs skyrocketed. A long period of steady and strong growth in electric power demand came to an end. The U.S. economy matured, losing much of its heavy manufacturing base and shifting more toward services. Given the new pattern of commercial activity, growth in power demand followed a more sporadic path and became more regionally differentiated. As a result, the appropriateness of the classic regulatory framework began to be questioned seriously for the first time.

From economies to diseconomies of scale

Finally, and perhaps most importantly, limits were reached in exploiting the economies of scale in generating technology. The approach of building ever-larger central generating stations, particularly nuclear and coal-fired units, no longer was suited to this new environment.[6] The intense concentration of new generating capacity in a small number of units with long lead times and uncertain performance, particularly in light of erratic demand growth, led in many instances to severe mismatch between load and available capacity. In a few instances, utilities experienced economic catastrophe when largely completed or even operational facilities were abandoned due to delays, capital cost overruns, and other problems arising from the sheer size, complexity and technical fragility of such plants. Beginning in the 1960s, environmental concerns became critical in the equation as well. Concerns about the environmental impacts of generating projects related to their size and technology led to proliferation of new hurdles, costs and delays, and community opposition.

At the same time, smaller, decentralized sources of electric energy appeared in the marketplace. A new generation of projects emerged, based on the concepts of smaller size, shorter lead times, modular construction, and simpler technology. Examples of these technologies include renewable energy resources (wind, solar, hydropower, geothermal biomass), combined-cycle, and cogeneration. Such projects could produce energy profitably given the umbrella of high energy costs prevalent at the time. However, prospects for success by these new entrants to the generation marketplace were limited by the monopsonistic market structure in place. The franchise system precluded retail sales in competition with utilities. Therefore, these alternate providers' only effective outlet for sale of their output was on a wholesale basis to electric utilities. Yet utilities, for a variety of reasons, were frequently unwilling to buy electric power, even when the cost of alternate providers' power was below that of utility system resources. This unwillingness led to pressure to reform the traditional framework and ensure a market for cost-effective supplies.

Policy responses to the new environment: The Public Utility Regulatory Policies Act of 1978

This reform took the form of a brief provision in PURPA, little-noticed at the time of passage in 1978. The overall intent of PURPA was to promote conservation of energy and reduce oil imports. In keeping with this objective, Section 210 of this legislation mandated the purchase of output from facilities at a rate based on the utilities' avoided cost of generating power themselves. These facilities which are principally generators using waste fuels, renewables and high-efficiency cogeneration processes are known as Qualifying Facilities (QFs).

This unheralded provision arguably had the greatest long-term impact of any section of PURPA, as it represented the first tentative

Section 210 … arguably had the greatest long-term impact of any section of PURPA … opening the door to competition within the utility industry.

6. *This observation is not meant to imply that economies of scale in generation have been altogether exhausted; the reversal of course and preference for smaller units was a response as much to economic and load uncertainty and high financing costs as it was to the technological limitations associated with very large nuclear stations. The possibility cannot be discounted that, in future years, conditions could change again, with large central stations or other large-scale technologies gaining renewed appeal.*

step by the U.S. Congress at opening the door to competition within the utility industry. After a series of legal challenges were resolved in the early 1980s, industry activity in response to PURPA took off. A full range of new industries sprang up to pursue particular technologies and opportunities that were afforded favored treatment under PURPA.

Congress extended to utilities and others the opportunity to compete freely in new generation projects while guarding against opportunities for abuse.

Rethinking the benefits of vertical integration

The initial efforts of Congress to open the utility markets to alternative power suppliers reflected not only the changing conditions of the generation marketplace, but also a broader philosophical change in government policy toward the regulated industries. This change brought about a reexamination of the costs and benefits of vertical integration.

For decades prior to the 1970s, electric utilities, gas pipelines and telecommunication companies operated under a monopoly franchise system that cut across functional areas. Franchise agreements granting exclusive rights across a range of activities reflected an assumption that these companies not only enjoyed economies of scale related to size, but also economies of scope related to their notional ability to provide a range of services on a combined or "bundled" basis more efficiently than if these services were offered by separate providers on an "arm's-length" basis.

During the 1970s, the seeds of a new era of competition were sown in certain segments of each of these industries. Yet the vertical integration of utility activities into areas featuring nascent competition seemed to be retarding the introduction of new technologies or lower-cost supplies. AT&T, for example, was resistant to allowing innovative equipment manufactured by other companies to be connected to its system, or to permit access to alternative long-distance carriers. Interstate gas pipelines were likewise unwilling to carry lower-priced gas supplies not under contract to them. The general unwillingness of electric utilities to purchase the lower-cost output of facilities they did not own presented a structural obstacle to lowering the cost of generation and made these lower-cost projects unfinanceable.

While these situations arose in different industries and jurisdictional contexts, a common thread ran through each. Policy makers recognized that large societal benefits were being lost because, in each instance, the combination of a sanctioned monopoly position and extensive vertical integration enabled companies in the subject industries to dominate arenas that were otherwise naturally competitive. Monopoly regulation, rather than protecting ratepayers, was perceived instead to confer upon the regulated entity an unwarranted competitive advantage, to the ratepayers' detriment.

As policy makers considered options for dealing with these situations, a common feature in their response in these different industries was the strategy of functional unbundling of complex services into component parts. Implementing this approach required an examination of the building blocks of the service and an exploration of the prospects and problems associated with differentiating the treatment of monopoly vs. competitive services. The objective of this approach was to facilitate competition where possible, thereby making it possible to employ light-handed regulation or even withdraw regulatory oversight and rely instead on market forces to bring greater discipline. Initiatives to promote competition in long-distance telecommunications, wellhead gas supplies, and wholesale electric power, while differing widely in specifics, reflect this common theme.

The early evolution of the IPP industry

PURPA was unexpectedly successful in reinvigorating the electric generation industry. By the end of the 1970s, the conventional wisdom was that power plant siting was virtually impossible and that the costs of new generating capacity were spiraling upward. Beginning in the early 1980s, however, a diverse industry featuring new technologies and refinements on existing technologies arose to take advantage of the market opportunities created by PURPA. Progressive refinements in existing technologies and contracting practices driven by open competition, led alternative power producers to offer more economically efficient and environmentally attractive supplies. The shift toward independent power helped to stabilize and reduce power costs from the historic highs of the late 1970s and early 1980s.

The need for further reform: The Energy Policy Act of 1992

In the longer term, the very success of PURPA brought recognition of its inherent limitations. The market for cogeneration projects linked to large-scale thermal hosts was inherently limited in size. As the best opportunities were developed and competitive generation opportunities became scarcer, pressure for further reform grew. By the late 1980s, the success of the competitive power marketplace influenced a growing number of policy makers and legislators to broaden their embrace of competition and undertake a retooling of the federal policy framework that had essentially been in place since 1935.

This new, pro-competition policy is codified in two narrow but crucial reforms contained in key provisions of EPAct. First, the EPAct creates a new category of competitive power producer, the Exempt Wholesale Generator (EWG). Any person or corporate entity, including electric utility-affiliated entities, may invest in such facilities without invoking the cumbersome strictures and reporting requirements of PUHCA. An EWG need not be a PURPA QF, and does not enjoy the rights of PURPA status; it must be a truly stand-alone generation facility selling in the competitive marketplace. Congress extended to utilities and others the opportunity to compete freely in new generation projects while guarding against the opportunities for abuse that gave rise to the passage of PUHCA in the first place. Second, the EPAct implicitly recognized the natural monopoly character of transmission service, and authorized the Federal Energy Regulatory Commission (FERC) to order transmission owners to wheel power for others at just and reasonable rates, upon receipt of a good-faith request.

[I]t is possible to dispense with the "second-best" approach of cost-based regulation ... and to realize the efficiencies associated with a true market-based system.

The original basis for organizing the electric utility industry in the form of vertically-integrated companies subject to cost-of-service regulation, it will be recalled, was based on assumptions that fit the world of the early 20th Century. These included the notion that utilities enjoyed economies both of scale and of scope, the hallmarks of natural monopoly. A consensus remains that transmission and distribution are functions that retain the character of natural monopoly. The appropriateness of applying this form of regulation in blanket fashion to all segments of the industry, however, has come under challenge as a result of recent developments. By the 1980s, market forces were dictating the construction of facilities in a size range in which vigorous competition is not only possible but a demonstrated reality. Furthermore, the nature of utility system operations had evolved to the point where it became feasible to harvest the benefits of competitive selection of generating units in long-term system planning decisions, as well as in short-run daily dispatch decisions. Within the generation sector, in short, it is possible to dispense with the "second-best" approach of cost-based regulation, with its skewed incentives and inefficiencies, and to realize the efficiencies associated with a true market-based system.

CONFLICTS IN TODAY'S GENERATION MARKETPLACE

The dramatic change in conditions discussed in the previous section made it possible to contemplate the discipline of competition in place of the traditional cost-of-service regulatory framework. Nevertheless, the disheartening reality is that the changing and confusing environment has given rise to more conflict and litigation than ever before. Throughout the nation, utilities and IPPs are engaged in a struggle to determine who will supply generation services, who will profit from this activity, and how the costs of generation will be determined and paid, under an ill-defined and evolving set of rules. This struggle occupies the attention and diverts the resources not only of the market participants but of overburdened regulatory commissions as well.

Many utilities welcomed independent power as an avenue to meet service obligations without taking on excessive financial risk. Others, however, resisted the incursion of the IPPs into their traditional markets. Many objections to independent power reflect concerns regarding its impact upon utility operations and finance. These concerns are often framed in terms of the defects of the PURPA regulatory framework, which imposes a mandatory obligation that utilities purchase the output of QFs. Candor requires that certain of these defects be acknowledged. The mandatory purchase requirement of PURPA, one of the chief sources of utility objections to that Act, may no longer be useful once the market evolves to a voluntary contracting environment. Most of the typical objections to independent power raised by utilities, however, relate to problems that have been mitigated or remedied as the market has evolved.

Perceived defects of the PURPA structure

At the time PURPA was drafted, the common expectation was that independent power generation would never constitute more than a marginal addition to the nation's grid, principally in the form of cogenerators harvesting waste heat at industrial facilities and small power producers employing waste materials as fuel. It was not widely expected that IPP operations would have a significant

Most of the typical objections to independent power raised by utilities … relate to problems that have been mitigated or remedied as the market has evolved.

impact on the overall system but would instead be accommodated in the general flow of power through the grid. In time it became clear that IPPs would constitute not merely a marginal fraction but indeed a majority of new capacity. As a result, a number of the following operational and financial concerns assumed growing importance.

Dispatchability. The fact that early contracts with cogenerators included no dispatchability provisions gave rise to important and legitimate operational concerns. Cogenerators' operations were keyed to the thermal requirements of their steam hosts and not necessarily synchronized with their interconnecting utility's daily and seasonal load profile. The growing number of such contracts gave rise to concerns about potential impacts on utility system economy and reliability. As the proportion of independent power increased, utilities began to specify dispatchability as a criterion in selecting new resources. The marketplace has proven responsive. Experience proved that this concern can be addressed contractually; more recent power contracts feature partial or complete dispatchability.

High rates of project attrition and unreliability. In the early phases of PURPA implementation, hundreds of developers appeared, ranging widely in their capabilities and level of sophistication. Many proved unable to fulfill contract obligations, and utilities complained of the burden of having to guarantee adequate service in the face of high rates of project attrition or the failure of IPP projects to perform to expectations. As the industry has matured, however, it has entered a period of consolidation. A smaller number of companies has emerged as sophisticated and effective competitors with proven track records. Moreover, a variety of contracting techniques were developed to safeguard against project failure. These included cash deposits, financial guarantees, and milestone schedules for project completion, as well as availability and other performance incentives. Reliability statistics for the IPP industry now show that it is not merely on a par with regulated utilities, but in fact achieves higher availabilities for comparable units.[7]

Administratively-determined avoided-cost tariffs. At the time PURPA was originally implemented, the costs of utility-constructed generating facilities were at an all-time high. Early tariffs establishing buyback rates in many states were keyed to these high costs through administrative proceedings. Critics contested these avoided-cost methodologies, contending that they led to inflated buyback rates and contributed to capacity surpluses in some markets. Unquestionably, PURPA implementation policies in several states in the early and mid-1980s were promotional, reflecting PURPA's strong policy preference for cogeneration in the face of an enduring national energy crisis. Indeed, the express intent of Section 210 of PURPA was to foster an infant industry. This goal was perceived as appropriate, given the promise of long-term energy efficiency and security benefits. In fact, the nationwide growth of the IPP industry vastly exceeded expectations. In some regions, projects were brought on line in an aggregate capacity that exceeded forecasted utility needs.

Nevertheless, criticisms of the linkage of IPP buyback rates to utilities' own avoided costs

7. *See, for example, "The Reliability of Independent Power: Operating, System, Planning, Fuel and Financial," National Independent Energy Producers, Sept. 1991; "Survey of Cogeneration in Texas and Louisiana," Gulf Coast Cogeneration Association, Oct. 1991; "Performance of Combined-Cycle NUG Plants Edges Similar Utility Units," Independent Power Report, February 26, 1993 (detailing a survey of gas turbines performed by GE Industrial & Power Systems).*

have become decidedly less relevant as the market has matured. Bidding and other forms of competitive procurement have supplanted the administrative determination of buyback rates in an increasing number of states. This development has led to more efficient pricing and, in general, dramatically lower price levels for output. More recently, sophisticated integrated resource planning has been used by many state commissions to address capacity needs, providing an important protection against the building of excess capacity.

Buy vs. build: bottom line impact. Perhaps the principal source of contention between utilities and IPPs arises from conventional rules of utility accounting. As providers of generation under the traditional rate base formula, utilities have an opportunity to earn returns for their shareholders in proportion to their investment in plant. As the practice has developed since the passage of PURPA, however, utilities in their role as purchasers of independents' output may not earn a margin. Rather, they are required to treat such purchases as a line-item expense, generally recovered on a strict dollar-for-dollar basis from ratepayers. Given that construction of rate base facilities is utilities' principal source of earnings, the lack of incentives to purchase power is tantamount to a disincentive, and can engender a conflict of interest in weighing the cost and profitability of different resource options. The issue of incentives for power purchases remains unresolved, although incentive-based mechanisms have been explored in several states. It is discussed further in the next section.

Many disputes between utilities and IPPs focus not on the inherent economics and other merits of their facilities, but rather on such artificial regulatory distinctions. Such disputes reflect continuing, real differences in market power. Too often these conflicts reflect a perception among utilities that IPPs are a nuisance or a serious threat, rather than a valuable source of supply. IPPs, for their part, are frustrated by the appearance that utility resource decisions are driven by the conflicting forces of regulatory imperatives and the utilities' need to protect their shareholders, and not by sound business principles of buying the best product at the lowest cost. As a result, IPPs themselves are often driven to inflexible, defensive positions and litigation. This cycle of conflict feeds the perception that a reciprocal, good-faith relationship is not possible.

Issues facing operating plants

The relative unattractiveness to utilities of contracting with IPPs would appear to be a key factor in the spread of tactics aimed at weakening the independent suppliers' position if not breaking long-term contractual commitments altogether. As purchased power contracts have grown in importance as a proportion of the utilities' mix of resources, access to information has become a critical issue, and certain utilities have inclined toward administering these contracts to the letter rather than in the spirit of a mutually beneficial relationship.

In a competitive environment, information has value. Regrettably, but unsurprisingly, utilities have been generally unwilling to share certain types of data with IPPs in a spirit of cooperation, unless compelled to do so by the force of regulation. Reluctance to share information is often premised on concerns for system reliability. Yet, in the view of IPPs, broader access to system planning and operating data could assist in more optimal dispatch and siting of new facilities, improving system economy and reliability.

Certain utilities looking to evade or minimize PURPA purchasing obligations have initiated

Many disputes between utilities and IPPs focus not on the inherent economics and other merits of their facilities, but rather on artificial regulatory distinctions.

programs of stringent contract administration. Some have sought to implement programs to monitor QFs compliance with the FERC's efficiency standards for cogenerators that, critics contend, usurp FERC prerogatives. By their terms, petitions to implement such programs have sought broad authority to cancel contracts with projects upon a determination of non-compliance by the utility. Some utilities have also sought authority to curtail QF purchases on the basis of operational circumstances during periods when QF rates exceed the utility's marginal production costs, even though such purchases may be well below the utility's avoided cost on a longer-run analysis.

A system that is most responsive to the best interests of customers would afford to utilities an undiluted incentive to acquire resources on a least-cost basis.

It has become common practice for utilities besieged with complaints about high rates to focus public attention on the allegedly high cost of IPP power. Often, comparisons are drawn between the energy-only cost of utility generated power and the total (energy plus capacity) price of IPP purchases. At the same time, these same companies extend great efforts through the regulatory ratemaking process to ensure the continued recovery of costs associated with utility-owned generating plants, even where a head-to-head comparison might show that IPPs' costs are significantly lower.

Issues in new resource selection

Similarly, many utility procurement processes aimed at obtaining new resources feature elements that seem to thwart effective competition. As the competitive power marketplace has matured, frivolous, unsophisticated and undercapitalized bidders have been thinned out. Participation in the process has come to require the completion of extensive work on projects and, therefore, the incurrences of significant expense. Yet, on several occasions, utilities have suspended or unilaterally canceled Request For Proposals (RFP) processes after bidders have incurred considerable expense to participate. Often the rules of a solicitation appear skewed toward a particular result. In many resource solicitations, utilities act both as player and referee, participating directly through the submission of bids and also conducting the bid review. The utility's presence on both sides of the table in such situations calls into question the impartiality of its evaluation. IPPs often face more rigorous bid requirements than the utility self-build option. Frequently, selection criteria are not announced, so that potential suppliers are left to guess at the customer's wishes. Many of the procurement processes implemented by state commissions in recent years have been highly prescriptive in nature. A common complaint of utilities and other participants is that such processes can be cumbersome and time-consuming. Utilities also voice the objection that mandated competitive procurement processes can result in the purchase of unneeded power, and deprive them of latitude to determine the timing and type of capacity needed for reliable and economical operation of their systems.

Dual roles and dual rules

This sampling of concerns with the current structure of wholesale competition highlights the conflicts inherent in having two sets of entities — vertically-integrated utilities operating under cost-of-service regulation, and market-responsive IPPs — operating in the same marketplace in accordance with different sets of rules. The existing framework pits utilities and IPPs against each other in an uneven and acrimonious relationship.

A system that is most responsive to the best interests of customers would afford to utilities an undiluted incentive to acquire resources on a least-cost basis, and would not rely upon a mandatory purchase obligation such as was imposed by PURPA. Generation, ultimately, is merely one of several inputs into the utility's final product, delivered energy service. To the extent that market-based approaches supplant cost-of-service regulation in the increasingly competitive environment of the future, utilities will look to competitive procurement of bulk power in the same way that they have traditionally looked to competitive procurement of transmission poles and cables, employee health care, and all other inputs — that is, as an opportunity to control costs. Success in competitive procurement of generation will translate into a source of competitive advantage and increased profitability, and not the specter of "vanishing rate base."

The natural role of the competitive wholesale power generator is as a supplier to the grid, and not as a competitor against utilities. If the rules of the marketplace made it explicit that utilities and IPPs operate in different but complementary market segments, both parties would have an increased appreciation of the importance of a cooperative relationship.

The natural role of the competitive wholesale power generator is as a supplier to the grid, and not as a competitor against utilities.

TOWARD A MORE DISCERNING MODEL OF REGULATION

The disparity between the regulatory treatment of utility-owned and independent sources of generation results in conflicts of interest and opportunities to abuse market power. An unstable and unduly adversarial environment has developed because of the lag in adapting these policies to the newly competitive environment. Because utilities are by their nature responsive to prevailing regulatory policies, regulatory reform can have a profound effect in defusing this tension by clarifying the blurred lines between competitive and monopoly services. Several states have begun formal or informal processes to sort through these issues.[8]

Distinctions in cost treatment for build vs. buy

As noted in the previous section, the historical evolution of rate base regulation and the PURPA framework along distinct paths has resulted in an arbitrary distinction. As utilities evaluate new resource options, this distinction leads to a systematic bias. Broadly speaking, one category of resources, utility-constructed rate base plants, is typically priced on the basis of actual final cost, irrespective of original estimates, plus an allowance for the utility's cost of capital. The other category, purchased power resources

8. *Among the most notable and advanced efforts aimed at regulatory reform is one undertaken in California. See, for example, "California's Electric Services Industry: Perspectives on the Past, Strategies for the Future," Dasovich, J., Meyer and Coe, Division of Strategic Planning, California Public Utilities Commission, Feb. 1993. More recently, on December 1, 1993, California Governor Pete Wilson filed a legislative proposal to revamp and streamline energy regulation in the state, disengaging the state government from close supervision of the electric supply industry, and turning to reliance on competitive market forces. Governor Wilson noted in a letter to legislative leaders that "(e)lectricity generation is now open to competition, with non-utility providers offering a dynamic alternative to traditional utility activity."*

FIGURE A

CONVENTIONAL ACCOUNTING TREATMENT OF UTILITY-BUILT VS. IPP-BUILT GENERATION

	Utility-built Plant	IPP-built Plant
Return to Utility Shareholders	Allowed ROE on net investment	No return
Cost of Power	Cost-of-service	Market-determined Fixed price or Formula

including independent power plants, is priced on the basis of firm bid prices that reflect market conditions. The IPP's cost of capital must be factored within its bid price. Conventions of regulatory accounting exclude any profit to the utility. The distinctions between these methods of cost treatment are illustrated in Figure A.

Addressing the purchased power disincentive

The nature of these discrepancies illustrated in Figure A suggests at least two paths to address the inconsistency. One approach that has been advanced in recent years would treat the underlying costs of each respective type of resource in accordance with the current approach (cost-of-service for utility generation, market-based pricing for IPP generation), but would institute some type of mechanism that creates a return to utility shareholders as a function of purchased power expense. Another approach would apply the same market-based pricing discipline to all sources of generation. This would require a new method, applied consistently to all resources, by which the utility would derive earnings associated with its performance of the supply function so that it could continue to attract necessary capital investment.

The first of these approaches is illustrated in Figure B (see page 23). It would leave the existing ratemaking treatment of utility-owned generation in place but provide a direct incentive for purchased power. Various forms of such an incentive have been proposed. It could take the form, for example, of a "split-the-savings" mechanism or an adder to a utility's cost of service, either associated directly with power purchases or more generally with the utility's capital structure. Alternatives include an increase to the allowed return on equity (ROE) or an increase in the imputed equity ratio. The effect of such a mechanism would be to give to purchased power the "look and feel," at least superficially, of utility-constructed, rate-base power. Such an approach would involve a fairly mechanical adjustment to existing ratemaking policy, and a principal attraction of this approach is that it would be relatively simple to implement.

However, where such mechanisms have been proposed, regulatory commissions have generally found that they lack a sound theoretical basis and can, in fact, have anticompetitive effects. Although the issue of the effect of power purchases on utilities' cost of capital has been aired before virtually every state utility commission pursuant to a requirement of the EPAct, no commission has recognized a systematic link between the two. An apt criticism of such a direct incentive mechanism is that it would tend to replace one form of distortion with another; it would be a matter open to question whether utilities should include or exclude the incentive payment to their shareholders in determining the costs of different options as actually seen by ratepayers. Ultimately, such an approach addresses the symptoms rather than the cause of the problem of skewed incentives, as it leaves in place the underlying rate-base framework for utility-sponsored generation. Regardless of shareholder impacts, the qualitative difference between rate-based and competitively-bid projects is so fundamental that a direct comparison between the two would be problematic if not impossible.

For these reasons, this incremental type of reform is widely regarded as a palliative measure at best. Proponents of a more fully competitive power market generally contend that truly efficient competition cannot exist as long as different categories of generating resources receive different types of treatment because of arbitrary regulatory distinctions.

FIGURE B

INCENTIVE PAYMENTS FOR IPP-BUILT GENERATION

	Utility-built Plant	IPP-built Plant
Return to Utility Shareholders	Allowed ROE on net investment	Additional payment to shareholders Higher ROE Higher equity ratio "Additional sum"
Cost of Power	Cost-of-service	Market-determined Fixed price or Formula

Revisiting the rate base concept

The approach to resolving this conflict in treatment of rate base and competitively-bid options presented in Figure C presumes a departure altogether from the historic rate base formula for utility generation investments.

The application of the model presented in Figure C to prospective resource decisions would, in effect, result in future generation investments being segregated from the rate base and accounted for on a stand-alone basis. Over time, as resources under contract supplant existing resources included in rate base, generation would be gradually and progressively unbundled from the vertically-integrated structure. In lieu of cost recovery through the monopoly rate structure, individual generating plants would establish prices for energy, capacity and any other services they provide on the basis of a clearly-articulated contractual relationship and would be corporately distinct from the purchasing utility.[9]

FIGURE C

EQUIVALENT TREATMENT OF ALL RESOURCES

	Utility-built Plant	IPP-built Plant
Return to Utility Shareholders	New basis for calculation (e.g., performance vs. benchmark; some type of subjective assessment; some other approach applied uniformly to all resources regardless of ownership)	New basis for calculation
Cost of Power	Market-determined Fixed price or Formula	Market-determined Fixed price or Formula

At present, the supply function affords to utilities the opportunity to earn returns principally as a function of the level of investment in plant; in the future, by contrast, supply-relat-

9. *It is expected that some entities will seek to sell power from groups of generators on a portfolio basis. Such innovative approaches should be encouraged, provided that the grouping of a portfolio of generators does not introduce problems of market power.*

ed earnings would be linked to some alternative measure of performance (except to the extent that some generating facilities remain in rate base). In all likelihood, the traditional utility rate structure would continue to be employed to recover costs associated with core monopoly services such as transmission, distribution and other services that the utility is uniquely positioned to provide. The provision of open-access, cost-based transmission service would be a critical element in ensuring the success of this model, so that generation procurement decisions can be guided by the real economic costs of generation alternatives.

The approach of functional unbundling of competitive and monopoly services ... has antecedents in other regulated industries.

Functional unbundling: experience in other industries

The approach of functional unbundling of competitive and monopoly services, as has been previously mentioned, has antecedents in other regulated industries. In the telecommunications industry, the continued prevalence of vertical integration in the 1960s and 1970s impeded the development of new services at a time when technological innovation was exploding. The unbundling of the vertically-integrated AT&T telecommunications monopoly in the early 1980s fostered the development of highly competitive markets in long-distance communications, equipment manufacturing, and a proliferating range of new services, many of which were not even envisioned at the time of restructuring. In this unbundled environment, telecommunications customers are free to specify the services they actually need, and the marketplace responds cost-effectively.

Likewise, for several decades, the natural gas industry was based upon the model of pipelines buying supplies in the field and offering bundled merchant service. The complex and frustrating wellhead price controls imposed in the early 1950s were ineffective in preventing price increases, but instead led to recurrent shortages, fears of impending resource depletion, and a 25% shrinkage in the size of the market from its peak year of 1970 to 1985. The complete unbundling of the pipeline industry pursuant to a series of landmark FERC orders between 1985 and 1992, and the complete elimination of wellhead price controls, have restored significant growth, introduced market discipline and expanded choice in the industry. Natural gas customers enjoy the benefit of ample sources of supplies at competitive prices that are a fraction of those projected in the late 1970s before this process of reform began. A range of innovative natural gas services, including pricing, storage, balancing, and other services, will be made available in this environment.

Models for unbundling are not confined solely to analogous situations in other industries, but can be found in the electric industry globally as well. Several governments have privatized national electric power systems in recent years; consistently, they have taken the approach of unbundling, rather than simply re-creating vertically-integrated structures in private hands.

Implications for resources: future, committed, existing

The paradigm of an unbundled generation industry carries several implications and raises a variety of questions. For obvious reasons, this model is being applied first to new resource commitments. Except in extraordinary circumstances, it should be possible to ensure that all future investments in generating resources are made within the framework of market discipline, in which prices or a price formula that establishes the parameters of risk allocation will be determined at the time the resource is selected from among competing offerings. Competitive power producers are likely to continue to contest all significant efforts by utilities to evade competitive market tests for new generating plant investments for which they seek rate base treatment.[10] In the current environment, utilities are the sole category of generator that, by virtue of their regulated status, enjoy the unilateral right to petition for rate increases based on a need to recover prudently-incurred but unanticipated costs. In an environment in which all power supplies are procured competitively, contract reopener rights for all parties would be established and limited explicitly by the terms of each supplier's contract.[11] The fact that some participants but not others have recourse to this right at present undermines effective competition, and if the premise of a workably competitive generation industry is accepted, such a distinction will become unnecessary.

Utility participation in the market

A related issue is the form and extent of utilities' participation in the market for new generation resources. At the present time, utilities may build capacity to meet their own needs on a cost-plus basis pursuant to the rate base approach, or contract with third parties to purchase generation at market-based prices. The issue of whether a utility may purchase generation from itself through a non-regulated affiliate structure at market-based prices is addressed in the EPAct, which establishes guidelines by which an entity attains EWG status. Regardless of ownership, EWGs, as stand-alone wholesale generators, may compete for opportunities in any market where they can demonstrate an absence of market power. Cases presenting a salient exception involve a utility-affiliated EWG seeking to sell power in (or adjacent to) the utility's service territory. In brief, under EPAct, such transactions are presumptively banned. However, a state commission may grant an exception if the proposed transaction meets a public-interest test that includes a finding that the transaction is market-competitive and that the affiliated relationship conferred no undue advantage on the EWG.

Treatment of committed and existing utility plants

While it will be relatively straightforward to treat future resource on an unbundled basis, more complex issues are certain to be raised to the extent that utilities and their commissions seek to apply the unbundling approach illustrated in Figure C (See page 23) to utility generation assets currently in the construction pipeline or in operation. With respect to projects to which utilities have committed funds with the expectation of conventional rate base treatment, a variety of case-specific factors would have to be considered if the ratemaking treatment of such investments were to be changed; no single prescription is possible. It is worth noting that there are relatively few utility generation projects currently in the

Critical issues ... include how the corporate structures of integrated utilities might be changed, as well as the valuation of existing plants ....

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10. *It cannot be ruled out a priori that some future generating resource or technology would exhibit natural monopoly characteristics and would warrant an exemption from the competitive process. Nevertheless, a strict burden of proof would be placed upon proponents of rate base treatment for any future generation investment.*

11. *While the logic of level competition requires that utilities as generators not enjoy preferential rights to seek regulatory relief for unanticipated costs associated with the generation function, a stronger assurance of cost recovery, in the form of cost-of-service regulation or some variant of it, remains appropriate for utilities in their other capacities. As providers of essential, natural monopoly services such as transmission and distribution, utilities accept the obligation to serve, as well as constraints on their expectations of financial return.*

pipeline. The very fact that little new utility construction has been initiated in recent years, and that the construction programs launched in the 1970s and early 1980s are largely complete, creates a "window of opportunity" to revamp the conventional ratemaking approach for generating plants without placing substantial amounts of pending investment in plants at risk for change in regulation.

The greatest challenge in implementing the model of functional unbundling involves how existing resources currently carried as rate-based assets would be treated. Participants in the debate over industry restructuring have proposed a full range of possibilities, ranging from complete divestiture of generating assets, to the spin-off of existing rate-based generating units into new subsidiaries, to the continued rate base treatment of existing plants on a "sunset" basis, among other possibilities. Critical issues to be addressed within each of these proposals include how the corporate structures of integrated utilities might be changed, as well as the valuation of existing plants in the event of a change from cost-based to market-based pricing.

Perhaps the most conservative approach, which would sidestep many of these issues, would be to continue the rate base treatment of existing facilities on a "sunset" basis for the remainder of their currently projected depreciation lives. In order to be consistent with the goal of market-based pricing for new resource commitments, this approach would require that expenditures of any substantial level to repower (i.e., increase the rated output) or extend the life of these facilities, or bring them into compliance with future environmental or other regulatory requirements that would otherwise require their retirement, should meet some type of market test and not automatically receive rate base treatment.

A key benefit of this conservative approach is that it would avoid disruptive changes to utilities' balance sheets in the short term while accomplishing the long-run goal of a more competitive power market. This model for reform implicitly assumes that the unbundling process can and will occur gradually and progressively over time. Existing plants would be spun out of rate base as they become fully depreciated.

Others are less sanguine about the durability of the current ratemaking system in the face of competitive market pressures. Skeptical of the gradualist approach, they contend that regulation cannot continue to protect utilities against additional losses on certain existing units as customers seek ways to avoid paying the rates necessary to support these facilities. Adherents of this view expect that utilities will, by force or by choice, take write-downs and possibly remove some or all of their facilities from the rate base on a more accelerated schedule as the market moves toward a structure in which services are offered and priced on an unbundled basis. Rather than allowing rate base regulation of generating assets to fade away gradually, they advocate a more activist approach with defined schedules and deadlines for action, such as was established for the breakup of the AT&T monopoly in 1984 or, more recently, for the natural gas supply and transportation industries through wellhead decontrol legislation and FERC Order 636.

The functional unbundling of generation, and the separate identification and pricing of distinct utility services, may involve but does not require the corporate divestiture by utilities of existing assets. Decisions regarding the disposition of assets removed from a utility's rate base, including the schedule of such actions, will in all likelihood be dependent upon a variety of local factors. Such decisions should be the prerogative of a utility's management, subject to the agreement of its state commission.[12] Competitive conditions in generation markets can be compatible with utility participation, and in fact the effectiveness of the competitive process may be enhanced, provided that the form of utilities' participation in this market is governed to ensure strict structural separation of generation from transmission and distribution activities.

The natural gas industry presents an appropriate model and analogy. The FERC's Order 636 abolished the pipeline merchant function and required that pipelines act strictly as transporters of others' natural gas. At the same time, it permitted pipeline companies, despite their continuing monopoly position in transportation, to maintain affiliations with companies engaged in the marketing of natural gas. Conditions governing the treatment of affiliated marketers, laid out in FERC Order 497, require that pipelines treat their affiliated marketing companies and other shippers in every respect as equals. Divestiture is not necessary provided that guidelines comparable to Order 497 can be enforced so as to ensure equitable treatment of all generators under contract to a utility.

It is likely, nevertheless, that many utilities will choose the path of divestiture as they respond to market forces and opportunities. The influence of competition is likely to lead to a variety of corporate restructuring activities, including mergers, division of some activities and recombination of others, and ultimately, a greater degree of specialization in the activities utilities pursue beyond their core utility functions.

12. *This applies both to those assets whose book value exceeds their market value, as well as those undervalued assets that would command a premium over book value in a fully competitive market.*

TRANSITIONAL ISSUES

Market forces and technological change have created the possibility of a truly competitive generation marketplace. The pronouncements of utilities and state commissions recognize the reality of competition in today's environment. Yet the adaptation of economic regulation to harvest the full benefits of competition has been slow, and is not uniformly embraced by the utility industry. By and large, utility regulation continues to presuppose the classical but now obsolete 1930s-era model of vertical integration and a cost-of-service, rate base treatment, with competitively-procured power treated as the exceptional case.

The "stranded asset" problem

The principal difficulty in plotting any departure away from the current vertically-integrated, cost-of-service framework toward an unbundled environment in which components of service are priced and offered separately is the issue of transitional treatment of existing high-cost sources of generation.[13] Cost-of-service regulation has allowed the accumulation of a variety of such problems, including high-cost sources of generation, high-priced contracts, and deferral accounts currently handled as regulatory assets on some utilities' balance sheets that may not be recoverable in a fully-competitive environment.

The problem of high-cost generation is, to a certain extent, localized. Many utilities will be able to acclimate to the new environment without a significant change in the ratemaking treatment of existing units, unless this is required by government policy. Some companies, however, may find it necessary or advantageous to take write-downs on their rate base, or spin existing generating units out of their rate base altogether, in order to be able to price their generation services more competitively in an unbundled environment. The question of how to assign value to uncompetitive rate-based assets in the process

13. *An additional problem, discussed further in this chapter, involves the numerous existing generating facilities, including numerous federal facilities, whose output is priced at below replacement cost.*

of transition, and where to assign the otherwise unrecoverable costs, has come to be known as the "stranded asset" issue.

This issue has become a matter of preeminent importance since the passage of EPAct, as evidenced by attention paid to the issue by utility credit rating agencies, investment houses, and other analysts. The dimensions of this problem have been variously estimated from the tens of billions to the hundreds of billions of dollars, and there is no broad agreement on how much uneconomic investment is at stake. EGA's objective in this paper is not to delineate the precise scope of this problem in terms of dollars. Rather, it is to note the importance of addressing the issue frontally as part and parcel of reform efforts aimed at harvesting the benefits of a more fully competitive wholesale generation market. Some possible approaches for dealing with the issue are suggested below in broad and qualitative outlines; before being implemented, any approach must be evaluated in considerably greater detail than is possible here.

The term "stranded assets" encompasses a variety of fixed costs, perhaps principally investments in large and costly nuclear and coal-fired generating facilities developed in response to the electricity shortages of the 1960s and fossil fuel crises of the early 1970s. Utilities face exposure to stranded investment to the extent that the costs of such facilities are included in rates but exceed the current and projected market value of power, or to the extent that these costs have been kept out of rates but allowed to accrue as regulatory assets subject to future recovery.

The problem of stranded assets or stranded investment can assume different forms. Many existing generating units are highly competitive on a variable-cost basis, yet are encumbered with high fixed costs related to initial construction cost overruns. Were such facilities to be spun off in the open market and priced on a stand-alone basis, it is likely that a portion of the fixed investment cost would become "stranded" and subject to a write-down, but the unit could otherwise remain competitive on a going-forward basis. Other units, particularly nuclear units with high fixed operating costs and fossil units with poor combustion heat rates, may prove to be uneconomical in a fully competitive environment. If subjected to competition, these facilities would cease to be useful and the actual asset would become stranded. The risk of stranded investment is not confined to utility units; in several states, existing, executed and approved purchased power contracts have come under pressure for termination or renegotiation because the contract rates have ceased to reflect competitive market conditions. In such instances, market mechanisms exist for bringing costs to market through arm's-length negotiations between the utility and the IPP seller.

EGA believes that an overriding goal in developing a transition policy should be to minimize the overall cost of the transition to the nation's economy....

The prospect of a further round of write-downs and write-offs in the utility industry is unwelcome, particularly since the industry has already been penalized over the past two decades as a result of plant cancellations and the construction of facilities that achieved operation at costs well in excess of initial projections. Nevertheless, the fact remains that significant embedded costs have yet to be recovered through current utility rates, and the likelihood of recovery of these costs is only diminished as competitive forces drive down the costs of new sources of generation. Fear of the loss of these investments drives many utilities to intransigent opposition to reforms that would expand competition. Just as major investments remain embedded in utilities' balance sheets, likewise, certain habits of mind among utilities, regulators, independent power producers and other stakeholders have become embedded features of the landscape, and impede progress toward resolution of this issue.

If anything, developments in the marketplace suggest two trends that could exacerbate this situation. First, there appears to be a marked resurgence of interest among utilities in adding rate-based facilities in recent years to compensate for the phenomenon of "vanishing rate base," possibly leading to a future buildup of unrecoverable costs in the event that these new facilities' costs exceed target levels. Meanwhile, in the absence of far-reaching regulatory reform, some customers, particularly large industrial and municipal customers, are positioned and motivated to pursue strategies such as alternative sources of generation, bypass, municipalization, and negotiated rate discounts. The common result of these actions is that utilities and their other customers are threatened with the prospect of large shifts in responsibility for the stranded costs that may result from this evolution toward a competitive wholesale generation market.

The inevitability of risk

The industry's adjustment to these new conditions must be premised on a recognition that, independent of the course of regulatory reform, competitive pressures have placed at risk all generation investments. Any course of action — including inaction — will affect the financial interests of utilities and millions of shareholders representing the entire spectrum of society. As the traditional regulatory bargain is recast and some method of dealing with high-cost assets is developed, it is certain above all else that not all stakeholders can be satisfied. Given this fact, EGA believes that an overriding goal in developing a transition policy should be to minimize the overall cost of the transition to the nation's economy, by achieving an early resolution of the stranded investment issue and by avoiding protracted litigation and uncertainty. It is reasonable to expect that policy makers will seek to ensure that costs are broadly distributed. Finally, as the generation segment of the industry evolves in a new direction, the viability of the core utility transmission and distribution functions must be assured. Issues of cost passthrough and cost absorption may arise as utilities pursue such strategic initiatives as asset sales, mergers and corporate restructuring to address competition.

It bears noting at the outset that the costs at issue have, for the most part, been approved by regulators and are already included in rate base; customers, in short, are currently paying for these facilities. Nevertheless, the onset of competition in such forms as self-generation, retail wheeling, and municipalization shows that these regulatory judgments pertaining to the allocation of fixed costs cannot necessarily bind all customers in an increasingly competitive environment.

[D]elay ... added considerably to the ultimate costs of restructuring the pipeline industry. This experience must not be repeated.

If a utility with a potential stranded asset problem establishes the objective of achieving a competitive posture in an orderly and timely fashion, then the pursuit of such a course should not open it up to relitigation of the issues that gave rise to its high-cost position. Past decisions regarding technology choices, projections of demand, and the anticipated costs of building, operating and retiring these facilities are vulnerable to hindsight judgment through the lens of history. But the contemporary record presents us with difficult issues. The initial decisions to build these facilities were undertaken in response to a significant national crisis, were supported by government policy, and were made pursuant to a regulatory model that held utilities exclusively responsible for meeting demand within their franchise areas. The chaotic evolution of environmental and safety regulations contributed in large measure to the spiraling costs of these facilities.

The danger of approaching a forward-looking transition by looking in the rear-view mirror of history is painfully illustrated by the recent history of the gas pipeline industry. The protracted litigation in the late 1980s of the prudency of take-or-pay contracts entered a decade earlier resulted in much heat, little light, and a major delay in achieving the FERC's articulated goal of an open access transmission system. This delay permitted the continued buildup of take-or-pay costs that added considerably to the ultimate costs of restructuring the pipeline industry. This experience must not be repeated.

It is the nature of competition ... to provide continual pressure for efficient operation and cost reduction, thereby lowering costs ....

In the case of the pipeline take-or-pay crisis, the financial stakes were raised and positions became more entrenched because large take-or-pay obligations were allowed to accrue before a mechanism was established for passing through these costs to ratepayers. In the case of the electric industry, by contrast, the fact that the rates currently being paid by customers already include costs associated with high-cost facilities suggests that there are rate design approaches to the stranded asset issue that would leave customers no worse off in the short run than at present, while introducing a greater measure of competitive pressure, ensuring the advantages of market discipline in the long run.

Under one promising approach that has been proposed, utilities that spin off high-cost assets would be preauthorized to enter into a binding contract to purchase the output of the facility for an established period at rates slightly below what the cost of power would have been assuming continued rate base treatment of the facility. The logic of this approach is that a facility offered for sale in the competitive market with such a contract attached to it should be able to command a premium over book value, so that the sale of the asset could actually generate a benefit to the utility's shareholders. At the same time, the requirement that rates for power sales be reduced below levels that would have otherwise applied will assure benefits to ratepayers. Finally, if the entity purchasing such a facility is able to realize efficiencies in operation that overcome the combined effects of the purchase premium and rate discount discussed above, then such an approach can yield a "win-win-win" outcome for the utility and its shareholders, its ratepayers, and the new plant operator.[14]

Transition models in other industries

As with the larger issue of functional unbundling, the experience of other industries presents suggestive illustrations of other kinds of mechanisms that have been employed to facilitate a transition from conditions of blanket regulation to open competition. A key element to a successful transition policy is that it not dwell in a backward-looking way on past controversies, but rather focus in a forward-looking way on ensuring appropriate and viable frameworks are in place for both competitive and monopoly services.

As other possible approaches are considered, two key elements in a successful transition are likely to be, first, the assignment of transition costs to the broadest possible base of customers; and second, the imposition of costs in the form of a temporary surcharge on the inelastic portion of customers' rates, effective-

14. *This mechanism discussed above was originated by Messrs. Richard P. O'Neill and Charles S. Whitmore of the FERC's Office of Economic Policy in an unpublished discussion paper entitled "Network Oligopoly Regulation: An Approach to Electric Federalism," presented at the Electric and Federalism Symposium, Princeton University, June, 1993.*

ly makes use of the utility's taxing power, which is significantly eroded if not eliminated in those segments of activity, that are subject to competition (e.g., generation).

Examples of the use of such an approach include, for example, temporary customer access charges added to telephone bills starting in 1984; take-or-pay surcharges added to invoices to local gas distribution companies and other direct customers pursuant to FERC Order 500; and gas supply realignment charges imposed pursuant to FERC Order 636. Outside of the context of utility regulation, in instances where the federal government has imposed significant changes in the operation of other types of industries that gave rise to short-term costs (e.g., banking and pension reform) as a matter of government policy, the costs of such actions have been spread across society through the tax code.

An alternative to the approach discussed above, which would reflect more closely the rate design mechanisms employed in the unbundling of gas supply from transportation service, might operate as follows. A utility would calculate the differential between the book value and market value of a high-cost asset, and then convert it from a generation-related charge into a form of transition surcharge. This charge would then be added to the inelastic portion of its system rates, most logically the distribution charge for retail customers and wholesale requirements customers, i.e., the utility's residual monopoly. The surcharge might be applied over a prescribed period of time, placing the utility at risk to achieve a target level of sales over its distribution system and rewarding it for actions taken to exceed that target. Alternatively, the surcharge could be imposed over a specified volume of sales, ensuring a precise reconciliation of costs. The application of the transition surcharge to a separately-stated distribution rate would mitigate, although it certainly could not entirely eliminate, the customer's incentive to seek alternative supply options.[15]

The foregoing illustration represents a simple situation. More complex situations may occur, for example, when the utility seeks to spin an asset out of its rate base but retain ownership of it through a wholly-owned subsidiary. In such a situation, a true third-party sale would not occur. Thus, some method would be required to ascertain the proper market valuation of the plant before an appropriate transition surcharge could be established. As a further complexity, situations may occur in which a utility has ownership in both "overvalued" and "undervalued" assets, (i.e., units that, whether because of low initial cost, accumulated depreciation or other factors, sell their output at rates below the market value of power.) Utilities possessing both overvalued and undervalued assets may be positioned to effect a transition toward a competitive pricing of their generating assets by simultaneously spinning off both categories of assets, calculating any necessary transition surcharge on the basis of the net differential between the market and book values of their combined assets.

The latter situation reflects the approach to gas supply contract reformation taken by the

It is time for stakeholders in the electric industry to come to a common understanding of the forces that are changing the industry, and to develop a new regulatory framework that can accommodate those forces.

15. *A criticism of this approach is that it would not address the incentive of a large industrial customer to engage in self-generation, or to move operations outside the distribution utility's service territory altogether, so as to avoid the impact of a distribution system surcharge. While this criticism is valid, it should be recognized that relatively few customers will be prepared to disconnect from the grid altogether, and the transition charges could be collected in the form of backup or standby rates. Furthermore, because the customer would, in exchange for paying the transition charge, gain access to generation services from the local distribution utility at rates that reflect market conditions, the incentive to bypass the utility as a supplier of power would be significantly mitigated or eliminated.*

FERC in its Orders 451 and 636. In the first of these orders, the FERC required pipelines that sought the renegotiation of high-priced take-or-pay contracts to place on the table at the same time those contracts they held with the same producers at below-market prices. This framework was established to provide for a comprehensive renegotiation that would result in more rapid movement toward market-clearing prices for both categories of assets. In the latter order, the FERC permitted pipelines to collect 100 percent of the costs associated with gas supply realignment activities pursuant to the restructuring rule. Recognizing the equitable sharing principle, the FERC permitted pipelines to recover 90 percent of these costs through inelastic pipeline demand charges; the final 10 percent were made recoverable through the commodity rate, thereby placing some competitive pressure on the pipeline to discount its rate for transportation service in order to recover these costs.

All of the transition mechanisms in the foregoing discussion are offered, not as definitive recommendations, but as illustrations of the types of options that might be available to promote a more rapid movement toward competitive pricing of all sources of generation, including existing units, for utilities that prefer this course of action. As mentioned previously, it is crucial to recognize that innovative rate design approaches may permit the recovery of transition costs in such a fashion that rates can be held at stable levels or even marginally reduced while generating assets are repriced at market-clearing levels and the incentives and pressures of a market-based pricing environment are introduced. The ultimate goal of competition, when all is said and done, is to secure lower prices for all consumers. It is the nature of competition, a dynamic process, to provide continual pressure for efficient operation and cost reduction, thereby lowering costs even further. It is commonly recognized that the system of economic regulation employed in the utility industry imposes a dead-weight loss in efficiency upon all ratepayers. There is ample reason to believe that a revamped approach to regulating the generation sector could harvest significant benefits and result in a "win-win" situation for all stakeholders.

CONCLUSION

In the wake of significant changes in generation technology and in the marketplace, a fully competitive market in electric generation is within reach. It is now possible to contemplate moving away from the "second-best" system of rate base regulation to a system that relies on competitive market forces to ensure a responsive and disciplined generation sector. Yet the benefits of competition are not yet being fully achieved. The failure of the existing regulatory framework to harvest these benefits arises, in large measure, from the conjunction of two factors: the continued use of cost-of-service regulation for utility investments in generation, and the vertically-integrated structure of most investor-owned utilities. The lag in adapting traditional regulatory doctrines to reflect prevailing conditions has contributed to an environment of conflict. In place of well-organized competition, there is an uneasy coexistence of IPPs subject to market discipline alongside utilities subject to traditional regulation.

Furthermore, many utilities are actively resisting increased reliance on the competitive marketplace. Some activities undertaken in response to the growth of the IPP sector may be characterized as rear-guard actions to fend off unwanted competition. Clearly, such efforts to stall competition will deprive ratepayers of long-term benefits. Yet these actions become understandable and even rational in light of the fact that utilities are responsive to existing regulatory policies and shareholder interests. Indeed, their fiduciary responsibility as private corporations is to preserve shareholder value.

Many of the conflicts that plague the industry and occupy regulators' attention could be averted through an update to the traditional utility bargain. A new, more discerning model of regulation must reflect the distinctive conditions of each segment of the industry. It requires a symmetrical balancing of rights, obligations and risks among utilities, wholesale suppliers, and customers. In EGA's view, the cornerstone of this new bargain is likely to be the functional unbundling of generation. This approach has a proven record of success in other formerly-regulated industries in the

United States and, indeed, is already being adopted or studied for the electric industry in other nations around the world.

This paper has attempted to acknowledge that the process of transition to an unbundled environment will be difficult and costly for some entities. However, this process may be no less difficult, and may potentially be far more costly, if the issue is deferred.

The introduction of competition in the generation sector has been an evolutionary process, with some missteps along the way. Nevertheless, when all of the results of the initiatives to date to promote competition are weighed in the balance, they have been clearly successful. Yet today's environment for power planning and procurement has become unacceptably contentious. Major decisions regarding the future supply of generating capacity must be made by the turn of the century if the nation is to accommodate economic growth, achieve compliance with stringent environmental standards, and maintain a healthy infrastructure.

For all of these reasons, it is time for stakeholders in the electric industry to come to a common understanding of the forces that are changing the industry, and to develop a new regulatory framework that can accommodate those forces. Participants in this process must not take for granted — indeed, should explicitly challenge — the traditional regulatory framework. To promote efficient decisions, the new framework must reflect the current realities of each segment of the industry. To be politically stable in the long run, it must synchronize ratepayer and shareholder interests. The need for such a consensus-building effort is compelling in light of widespread customer dissatisfaction with the status quo. EGA offers this paper in the hope that it will move the consensus-building process forward.