POTENTIAL COSTS AND BENEFITS
OF ELECTRIC INDUSTRY RESTRUCTURING

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EXECUTIVE SUMMARY

Background

Proponents of restructuring claim that deregulation and increased reliance upon market forces will lead to a more economically efficient electric utility industry, with ultimate net benefits, especially lower prices, to everyone. However, skeptics of deregulation point out that the assumption that increased reliance on competitive forces will enhance economic efficiency and provide net benefits to all ratepayers has not been supported with sound analysis and is still a controversial hypothesis. In considering the economic implications of electric industry restructuring, it is useful to begin with a few fundamental questions:

- What is economic efficiency?
- Are low prices always economically efficient?
- Will competition lower costs to customers?

One's answers to these questions, particularly the third, are crucial to determining a course of action on restructuring.

Economic Efficiency

There are many concepts of economic efficiency. No single concept provides an adequate framework for considering the wide range of economic effects that would be caused by electric industry restructuring. Technical efficiency refers to producing a fixed amount of a product using the smallest possible amount of inputs. For electric power systems, technical efficiency is largely a matter of technological development, economic dispatch, coordinated operation, good management, and sound planning. Technical efficiency does not, however, address the question of how much electricity should be produced.

Price efficiency is achieved when the price of a product is equal to its long-run marginal cost of production. This should lead to an optimal amount of production and consumption of the product, resulting in the most efficient allocation of society's resources across markets. However, price efficiency does not speak directly to the issue of whether consumers are better off when price equals long-run marginal cost.

Prices and Efficiency

Technical efficiency translates rather directly into lower prices since fewer inputs cost less. Price efficiency is, however, a different objective and sometimes conflicts with lower prices. Consider, for example, a situation in which the retail price of electricity set by regulators was 4 cents per kWh, based upon the current embedded cost of generation. If the long-run marginal cost of providing electricity were currently 5 cents per kWh, then under deregulation it would be economically efficient...
to raise the price to 5 cents per kWh. Obviously, consumers might not like such an outcome, even though economic efficiency would have increased.

Moreover, the economic theory which calls for price to equal long-run marginal cost also requires that any externalities (e.g., environmental costs) be included in the marginal cost in order for the outcome to be efficient. This would generally amplify the extent to which lower prices would often be economically inefficient, as in our example above.

**Could Competition Lower Prices?**

It is unclear whether or not competition could lower prices paid by consumers because there are many potential counteracting effects, both in the short run and in the long run.

In the near-term, by far the largest potential financial impact on ratepayers of increased competition in the generation market will be determined by the regulatory treatment granted to uneconomic, or “strandable,” costs which are estimated at more than $20 billion per year nationally, or more than 15 percent of the average price of electricity. Stranded costs are the difference between the competitive market value and the regulated book value of a utility's electric generation assets. Consumers have been, for the most part, paying for all strandable costs as these costs are included in regulated rates. With full recovery of strandable costs by utilities from ratepayers, there would be no immediate electric price reduction from restructuring the industry, regardless of market prices. Only stranded costs written off as a loss against stockholder equity would tend to decrease near-term prices to consumers, but since this would merely be a transfer or a sharing of sunk cost responsibility, it would not have any direct impact on economic efficiency. (There could, however, be important "indirect" effects of large transfers.) Under current regulatory practices, strandable costs will tend to decrease significantly over time, as generating plant assets depreciate. Thus, for most utilities, strandable costs will disappear within 5-10 years, even if the industry is not restructured.

Competition could also lead to stranded social benefits, such as the discontinuation of cost-effective utility demand-side management programs or low-income programs. From the narrow perspective of economic efficiency, eliminating DSM could be seen as efficient, if it moves prices toward marginal costs, or if technical efficiency is framed in terms of $kWh$ of production as the relevant product. However, a broader notion of efficiency might reach the opposite conclusion, either because externalities are included in marginal costs, or because technical efficiency is framed in terms of energy services, rather than production of kWh, as the relevant product.

There are also many opportunities to decrease electricity prices over the long run. One such opportunity is through improved system operation. As a practical matter, however, these opportunities are limited and already substantially employed. Any further improvements in regional coordination and power pooling would likely reduce prices by only about two or three percent on a national average basis, though some regions could benefit more. Implementation of FERC Order No. 888 should help achieve these savings within the context of wholesale competition.
Another opportunity to decrease electricity prices deriving from increased competition is in the area of labor costs of competitive services, primarily the generation function (under retail or wholesale competition), and secondarily, the aggregation function (under retail competition). Reduced labor costs could come from reducing staff size at power plants, or reducing labor at utility headquarters and field offices. Of course, such efficiency improvements would have to be weighed against potential losses in economies of scale and/or scope that could result from competition. Also, economic efficiency could decrease under retail competition due to any increase in transaction costs for signing up and marketing to customers by aggregators, relative to the economies of scope and scale experienced by vertically-integrated utilities.

If generation investments are no longer regulated and reasonable rates of return on equity are no longer guaranteed by regulators, the cost of new generation may be higher in a more competitive environment than it would be under continued cost-of-service based regulation of generation. The capital structure for generation projects will likely shift toward a higher proportion of equity, and toward higher required rates of return for these riskier generation investments. These increases could offset any reduction in direct construction or labor-based operating costs that result from market pressures.

The performance and level of competition in generation markets will be the key factor in determining prices in a deregulated environment, since generation is currently about two-thirds of the retail price of electricity. If any one firm is too large, or for some other reason has a strategic position allowing it to influence the market price, then market failure will occur and some form of corrective regulation may be necessary. In many regions of the U.S., market power, due to high concentration of generating plant ownership, will likely be a problem if current ownership patterns do not change. If generation ownership is consolidated with mergers and acquisitions, then this problem of "horizontal market power" will be that much worse.

**Different Restructuring Models**

The potential magnitude of each of the above impacts depends, in part, upon the specific restructuring model being considered. Every impact noted is relevant to some extent to all wholesale and retail competition models. In general, the magnitudes of the effects, or the extent of competitive pressures, will likely be greater under retail competition than under wholesale competition. At this time, it is impossible to tell whether the potentially larger cost reductions under retail competition will outweigh the potentially large implementation and transaction costs to produce net savings.

The impacts of restructuring will also be state- and utility-specific in many respects. This report will discuss broad categories of costs and benefits in a fairly general way, leaving location-specific considerations to be addressed elsewhere.

**Policy Options**
We recommend that policy makers think clearly about their objectives in wanting to restructure the electric industry, and take a particularly critical view of vague objectives such as "economic efficiency" that may not be clearly defined, or not even desirable in some applications.

In addressing strandable costs, regulators should first quantify these costs over an appropriate timeframe. Even for utilities which currently have high embedded costs, the stranded cost calculation may include a future period of "negative stranded costs" as an offset to the near-term positive stranded costs. Then regulators should address the issue of how to share strandable costs between utility shareholders and ratepayers.

Regulators should also consider measures to protect strandable benefits that the current regulatory system provides if they want to modify the current system substantially. For DSM programs, low-income programs, incremental environmental improvements, and certain types of resource diversity programs that may not be provided in a competitive market, the required funding (to the extent that these programs require funding in utility rates) could be provided through a non-bypassable system benefits charge.

**Conclusions**

Given the uncertain range of costs, benefits and risks likely as a consequence of industry restructuring, regulators and legislators should consider an incremental approach to restructuring, in which the competitiveness of wholesale markets is tested and developed, and the costs and benefits assessed before embarking on retail competition. It may be the case that establishing a truly competitive wholesale generation market in combination with a substantial sharing of strandable costs by utility shareholders may achieve most of the goals of industry restructuring advocates. It is important not to sacrifice fundamental long-run objectives for short-run price considerations, by rushing to make changes to a regulatory structure which has probably performed well for a majority of ratepayers, especially when the consequences of many of those changes are very hard to predict. Much more research is needed on key issues affecting restructuring, especially research on how to measure and mitigate market power and how to ensure real competitive options for small or low-income customers.

Ultimately, the bottom-line tradeoff is whether the potential costs and risks of each aspect of restructuring are worth the potential benefits on an incremental basis. It is our hope that this report on the costs and benefits of electric industry restructuring will contribute toward an informed dialogue on the opportunities, risks, and tradeoffs involved in this enterprise.
Selected References


I. ECONOMIC EFFICIENCY AND LOWER PRICES

I.A Purpose of this Study

Proponents of restructuring often claim that deregulation, with increased reliance upon market forces, will lead to a more economically efficient electric utility industry, with ultimate net benefits for everyone, especially lower prices. However, the assumption that restructuring will enhance economic efficiency and provide net benefits to all ratepayers has not been supported with sound analyses and is still a controversial hypothesis. The purpose of this study is to carefully examine this assumption, to identify where some impacts of restructuring can be estimated, and to help identify areas where meaningful research has yet to be done.

In this report, we have attempted to distinguish the qualitative impacts of restructuring across many dimensions: some effects of restructuring may be immediate while others are strictly long-term; some are relatively certain, while others are simply unknown; most cost impacts will be shared differentially across stakeholder groups (indeed, one group's benefit may be another group's cost); and some effects are specific to the restructuring scenario considered (for example, wholesale and retail competition have different sets of potential impacts). Our aim is to provide a conceptual framework that will be useful to utility regulators, state legislators, and others as they consider the relevance and economic merit of various electric industry restructuring proposals for their state or region.

In considering the economic implications of electric industry restructuring, it is useful to begin with three fundamental questions:

- What is economic efficiency?
- Are low prices always economically efficient?
- Will competition lower costs to customers?

One's answers to these questions, particularly the third, are crucial to determining a prudent course of action on restructuring.

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1 For example, David Rolka, Pennsylvania Public Utility Commissioner, states “Restructuring of the electric industry is the current regulatory fashion ... being driven by a set of untested assumptions which link public benefits to competition.” Statement of Commissioner David W. Rolka, Docket No. I-940032, September 27, 1995. In addition, many analysts look to the restructured utility industry in Great Britain for guidance, perhaps not realizing that the average price of power there is about 12.5 cents (U.S.) or about 50 percent higher than the current U.S. average. Centre for the Study of Regulated Industries, The UK Electricity Industry: Charges for Electricity Services 1995/96, The Chartered Institute of Public Finance and Accounting, London, September 1995.
I.B  What is Economic Efficiency?

I.B.1 Objectives of Restructuring

Partial deregulation of the electric industry in the U.S., especially the generation sector, has been proposed as a means of both lowering rates and increasing economic efficiency. (The transmission and distribution services are natural monopolies and thus will remain regulated.) For example, the first of ELCON's eight principles for "achieving competitive, efficient, and equitable retail electricity markets" is that "market forces can do a better job than any government or regulatory agency in determining prices for a commodity such as electricity." Similarly, authors Adam Jaffe and Joseph Kalt explain that "the current restructuring debate is driven by economic and historical analysis that suggests that the efficiency of the electricity industry could be enhanced by increasing the role played by competitive market forces in the industry, thereby reducing the need for economic decisions to be governed by regulation." Generally, then, restructuring advocates are seeking a different balance between the roles played by market forces and by regulation. However, as we explain in the remainder of this section, the goals of lowering rates (ELCON's goal) and increasing economic efficiency (which markets tend to do if competitive) are not identical, and, in some situations, may conflict. In fact, this basic tension is at the heart of many of the restructuring debates.

One of the primary goals of electric utilities and their regulators is to minimize prices, subject to various social constraints. In most states, the laws under which the state utility commissions regulate electric utilities use the words efficiency, reasonable rates, or both. For example, the Missouri regulations specify that a fundamental objective of utility regulation is to ensure that the public is provided "with energy services that are safe, reliable and efficient, at just and reasonable rates, in a manner that serves the public interest." Note, however, that reasonable rates are not necessarily the lowest possible rates. In the past, the goal of reasonable rates was met through cost-of-service regulation.

As a general matter, competition is not an end in itself. Rather, it is lower prices to customers, or some notion of "economic efficiency" that is the goal. Competition, then, may be a useful tool for achieving the goal. Even if a reasonably close approximation of a "perfectly competitive market" can be achieved, that may not be desirable if, for example, that market neglects societally important considerations such as environmental and other externalities.

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2 ELCON stands for The Electricity Consumers Resource Council, based in Washington, D.C., and is an organization that lobbies on behalf of large industrial electricity consumers.


5 Missouri Title 4 CSR 240-22.010 Policy Objectives.
I.B.2. Types of Economic Efficiency

Strictly defined, economic efficiency (or "pareto optimality") is merely "an allocation of resources in which no one individual can be made better off without making someone else worse off." However, this strict definition is so abstract and limited as to be nearly useless for purposes of any practical analysis of utility industry policy. A slightly looser (and only slightly more useful) definition of economic efficiency is a resource allocation in which "no activity can be increased without cutting back on some other activity." Grand attempts to construct an aggregate single measure of economic welfare as a basis for measuring economic efficiency (e.g., maximizing total satisfaction to consumers) in the electric industry are inevitably somewhat arbitrary and not well-founded in observable behavior, especially given all the social factors considered in utility ratemaking.

No single framework for, or definition of, economic efficiency provides an adequate basis for considering the wide range of effects of electric industry restructuring. We will, therefore, take a pragmatic approach in this report, and focus primarily upon two reasonably tractable aspects of economic efficiency: technical efficiency and price efficiency. These may be thought of as conditions necessary for an economically optimal state.

Technical efficiency is a straightforward concept: it implies producing a fixed amount of a product using the smallest possible amount of inputs. This is also sometimes referred to as "production efficiency." For electric power systems, technical efficiency is largely a matter of technological development, economic dispatch, coordinated operation, good management, and sound planning. Not surprisingly, technical efficiency does not address the question of how much electricity should be produced.

Price efficiency is also straightforward in concept; it is achieved when the price of a product is equal to its long-run marginal cost of production. This should lead to an optimal amount of production and consumption of the product, resulting in the most efficient allocation of society's resources across markets. Price efficiency is closely related to the concept "allocative efficiency." However, price efficiency does not speak directly to the issue as to whether consumers are better off when price equals marginal cost.

Both of these concepts of efficiency can be considered with or without "externalities," the consequences of resource development or consumption that are not directly accounted for in the prices of the resource to its suppliers and consumers. However, including or ignoring externalities can, as a practical matter, have a very large impact on an analysis of electricity policy options. It is important to understand that the economic theory that gives "economic efficiency" its status as a goal for policy also requires that externalities be considered. Often, however, the consideration of

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externalities can be quite controversial, partially due to the subjective nature of values and differences in perspectives on how to quantify externalities. The experience of trying to determine the appropriate role for environmental externalities in the utility industry over the past decade has been particularly controversial. Therefore, we will attempt to present discussions of issues both with and without externalities, and to briefly point out where external costs may be particularly important.

A third aspect of economic efficiency has to do with variety. A market that offers a wide range of varied products and services may be more efficient in the sense of better meeting varied customer needs and desires, than a market that is limited to a single homogenous product or a narrow range of products. We will touch upon this issue in a later section on electricity options, but will focus primarily upon the technical and price aspects of efficiency in this report.

I.C Are Low Prices Always Economically Efficient?

Improved technical efficiency translates rather directly into lower prices since fewer inputs cost less. However, price efficiency (price equal to long-run marginal cost) is a completely different objective and sometimes conflicts with lower prices. Consider, for example, a situation in which the retail price of electricity set by regulators was 4 cents per kWh, based upon the current embedded cost of generation. If the long-run marginal cost of providing electricity were currently 5 cents per kWh, then under deregulation it would be economically efficient for the price to rise to 5 cents per kWh. Obviously, consumers might not like such an outcome.

To better understand this issue, care must be taken in defining the terms "prices" and "marginal costs." The current average price (or rate) for electricity includes the costs of generation, transmission, distribution and "other." However, market-based competition is only being considered for the generation of electricity and for some "other" services (which are relatively low cost), so it is primarily the price of generation that is of interest here. The national average prices of the various components of the cost of electricity are shown in Figure 1, below, on an approximate basis for 1993. The economic and uneconomic cost of generation tends to make up about 70 percent of the costs included in rates and is about 5.0 cents per kWh out of average retail rates of 7.2 cents per kWh. (See Figure 1.) Furthermore, the total cost of electric generation (namely, the 5.0 cents per kWh) is composed of a fixed (or "capital") cost component and a variable (or "energy") cost component. Current marginal energy costs, namely the variable costs of producing the last kilowatt-hour (kWh) of electricity demanded, are low; typically they range from 1.0 to 3.0 cents per kWh, with an average of about 2.0 cents or less, depending on the location and time of day. Therefore, the fixed costs of existing generation are typically the major contributing factor to current total prices of electric generation, averaging about 3.0 cents per kWh.10

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9 Recall that transmission and distribution (wires services) are natural monopolies and thus must remain regulated.

10 Note that the figures discussed here are current national average conditions. Local circumstances can vary considerably. Also, the relationship between prices and marginal costs will change over time. Many regions of the country currently have excess baseload capacity. As the capacity situation tightens with retirement and/or load growth, marginal costs will tend to increase.
The marginal cost of generation is considered to be the total cost of new generation, since it is assumed that new generation would be built to meet growth in electricity demand. If an optimal mix of new gas-fired generating capacity were built from scratch to serve a typical utility's system load (at average load factors), the total generation cost (fixed and variable) would be about 4.0 cents per kWh. When we compare this "marginal cost of new generation including the cost of reserves" to the price of total generation in current average retail rates, we see that the generation portion of current rates is typically about 30 percent higher than the estimated cost of providing the same amount of electricity from new generating resources. Thus, this comparison provides us with a sense of the magnitude of the production inefficiencies that competition in generation might eliminate, if it could be introduced immediately. On a national average basis, then, this competition might reduce average retail rates from 7.2 cents per kWh to 6.0 cents per kWh, or perhaps somewhat less if additional labor costs could be reduced, based on long run marginal costs. (See Figure 1.) Remember, though, that fully competitive generation markets cannot be introduced overnight. Also, if uneconomic generation costs are put into a transmission charge and recovered from customers, then this price decrease would not occur (see Section III.B. below).

As stated in the beginning of this section, the important distinction between low rates and increased economic efficiency has been overlooked in much of the discussion and literature on electric industry restructuring. Most people do not seem to be aware of the fact that if suddenly the electric generation industry switched over night from price regulation to price competition based on long run marginal costs, and if the market price of electric generation turned out to be higher than the regulated electric rates, this could be "economically efficient." In other words, it might be "efficient" for those utilities, with generation prices below 4.0 cents per kWh to raise their prices to 4.0 cents per kWh. (Indeed, if the environmental externalities of power supply were considered as part of economic efficient pricing, then economic efficiency would call for generation prices that were even higher.) Furthermore, over the next ten years the average cost of existing generation will tend to fall due to depreciation of the generation assets, and market prices may tend to rise due to inflation. Potentially, this might require more utilities to raise their rates in order to have economically efficient prices. It is important that industry stakeholders seriously considered the desirability of this scenario.

Retail electricity prices in the U.S. vary considerably by utility and by customer class. Illustrative prices are shown in Figure 2. Prices to industrial customers range from about 3 cents per kWh for low cost utilities to about 12 cents per kWh for high cost utilities. Prices to residential customers are somewhat higher, ranging from about 5 cents per kWh to about 16 cents per kWh. The marginal cost of new generation will also vary somewhat by system as the prices vary, but perhaps more importantly it depends upon whether or not externalities are included. For example, the short run marginal cost of generation currently is in the range of 1.5 to 2.5 cents per kWh for most systems. Over the longer term,

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11 This value is in real levelized 1995 dollars, based on a 15-year period, and reflects a load factor of 63% of the national average load factor and reserves of 20%. Data was obtained from the Technical Assessment Guide (TAG), Electric Power Research Institute (EPRI), Volume 1, June 1993. Note that new gas CC units may have fallen in price since 1993. Whether market prices would reflect real levelized costs, or some higher price, itself an interesting and important technical question.

12 A few utility systems have very high embedded generation costs, primarily due to uneconomic nuclear plant investments, while a few others have very low embedded generation costs, primarily attributable to older hydro-electric resources.
when new capacity is required to meet load, avoided generation costs will tend to be in the 3 to 5 cent per kWh range depending upon many factors including, again, fuel prices, generating technology costs and performance, and load factor. These costs are "direct" costs, excluding externalities. If environmental externalities -- the costs of negative impacts of generation upon the environment and public health -- are included, then the marginal costs can be considerably higher, by 1.5 cents per kWh or more. Interestingly, the inclusion of environmental externalities tends to level out the difference between the short-run and long-run marginal costs, since the emissions and therefore the externalities of the existing facilities that dominate the short-run marginal costs are relatively much greater than the emissions of the new facilities that make up the long-run avoided costs.
<figure 2: MAX_FIGS.XLS (Excel 5.0)>
I.D Will Competition Lower Costs to Consumers?

The reasons for possible price reductions under competition differ in the short run and in the long run. Any price reductions, in the aggregate, will come from either removal of uneconomic costs from rates (see Section III.B on stranded costs) or from efficiency gains. In the short run, technical efficiency gains would come primarily from operating and dispatching existing electric generating plants on a least-cost basis, as well as from cost-effective reductions in operations and maintenance expenditures. In the long run, they would come from the components of an optimal resource mix over time. Technical efficiency is not likely to significantly change the price of most utility systems in the short run, and it may only cause prices to decrease slowly in the long run as new supply resources are added.

Of course, as noted above, the main driving force behind the electric industry restructuring debate is the current high cost of electricity in many parts of the U.S. High electricity rates can be caused by uneconomic costs resulting from the high costs of constructing, operating, and maintaining certain types of generating plants and/or from utilities having invested in inappropriate mixes of plant types and demand-side management programs (i.e., energy conservation and load management). In many cases, ambitious construction programs involving capacity with long lead times were undertaken to serve demand growth that did not materialize. Falling gas and oil prices since the mid-1980s rendered these units even more uneconomic. Thus, even where system planning and plant construction were "prudent," the outcome was often "uneconomic." Therefore, achieving technical efficiency is a prerequisite for lower rates for most utilities, but lower rates alone do not necessarily imply economic efficiency. To exemplify this latter point, if a utility does not make any cost-effective investments in conservation technologies, its rates may be lower than they otherwise would have been, but the utility will not have achieved maximum technical efficiency with regard to its resource mix. Since, as noted above, the primary cause of high rates is too much capital investment, for most utility ratepayers the only way of achieving price reductions in the short run is for utilities to write off some of this excess investment against their stockholders' equity. (This issue of how to deal with this existing excess investment, known as "stranded costs," from a regulatory perspective will be discussed at length later.) Thus, we can conclude that if competition leads to improved levels of technical efficiency, then it will tend to lower costs to consumers. Note that the introduction of integrated resource planning (IRP) over the last ten years was an attempt to do the same thing within the regulatory context.

Overall, whether competition lowers costs to customers in the long-run is primarily a matter of how well the market works, and the extent to which opportunities for improvements in technical efficiency can be realized. We note that aside from the downsizing that many utilities are undertaking, the technical opportunities are limited and are primarily a matter of wholesale competition. The uncertainties and transfers (between customers and investors and between classes of customers) are relatively large. In the short-run, whether competition lowers costs to customers is almost entirely a matter of how stranded costs are treated. With accelerated recovery of strandable costs, rates will tend

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to stay level or increase. With sharing of stranded costs, and the associated write-offs, rates will tend to decrease accordingly.
II. ELECTRIC INDUSTRY RESTRUCTURING - GENERAL CONSIDERATIONS

The various electric industry restructuring proposals and alternative ratemaking proposals currently under consideration in states throughout the nation share a common theme: they are intended to foster the transition of as many electric service markets as possible from monopoly to competitive status.\textsuperscript{14} Generic proposals center around two basic industry models. One introduces competition for generation resources at the wholesale level only. The other introduces competition for generation at both the wholesale and the retail levels.

\textit{Wholesale competition} refers to owners of electric generation (e.g., utilities and independent power producers (IPPs)), whether regulated or not, competing against one another to sell power to regulated electric distribution companies, which in turn sell the power to retail customers (e.g., residential, commercial, and industrial consumers) served by that distribution company. Wholesale competition exists to a limited but growing extent under current regulation and integrated resource planning (IRP) practices, in that some utilities meet an increase in demand (or a decrease in their existing supply) by making cost-effective power purchases using competitive bidding procedures rather than by constructing new plants that they would own.

However, many of the wholesale competition models now under consideration would go well beyond IRP and competitive bidding. For example, a state regulatory commission could set an unbundled, but regulated, rate for wholesale generation that is sold to retail customers such that the rate would reflect the prices that a competitive market does (or should) yield. This has been called "linked generation" pricing. Under other models, utility ownership of generation could be functionally separated from ownership of transmission and distribution, spun off into a utility subsidiary, and allowed to function under competitive market conditions.\textsuperscript{15} Alternatively, utility ownership of existing generation could be completely divested\textsuperscript{16} from ownership of transmission and distribution and spun off into independently owned entities.

Any wholesale restructuring model requires that all distributors of electricity and all generators have comparable access to electric transmission systems, and that the prices for transmission services be set on a nondiscriminatory basis. This is the subject and goal of FERC’s Order No. 888. Since the provision of transmission services constitutes a natural monopoly,\textsuperscript{17} it would, therefore, remain regulated by the Federal Energy Regulatory Commission (FERC), whether wholesale or retail competition exists. Similarly, state regulatory commissions would continue to regulate the supply

\textsuperscript{14} Besides generation, other electric service markets being discussed include DSM and energy management systems, customer billing, and a few generation related ancillary services.

\textsuperscript{15} Wholesale competition models also vary in terms of the extent to which generation would be deregulated.

\textsuperscript{16} By “functional” dis-integration we mean separating the administration, cost accounting, and operation of generation from transmission and distribution. Wholesale competition models vary in terms of whether or not they would require generation ownership to be divested from transmission and distribution ownership.

\textsuperscript{17} A “natural monopoly” is a market in which minimum average cost can be achieved only by having one seller of a good, and that seller exhibits diminishing average cost over a broad range of output levels. (Nicholson, 1985: p.419).
planning activities and distribution services provided by the local distribution companies, because retail customers would not have the option to purchase these monopoly services directly from a provider other than their local utility. It is important to note that under this scenario for enhanced competition, IRP could continue as a means to enhance technical efficiency. Efficient pricing could be pursued either by allowing a fully competitive generation market to set the generation component of rates, or cost-of-service regulation (perhaps combined with performance-based ratemaking approaches) could continue for existing generation units with the cost of generation from only new units (based on contracts between the generating and distribution companies) being folded in based on market prices.

Retail competition, or "direct access," models provide the opportunity for retail customers to purchase electricity directly from generation entities, or indirectly through aggregators, brokers, and marketers. Independent aggregators, brokers, and marketers would likely play a key role in this market, aggregating customers and matching customer demand with suppliers, just as distribution utilities do today. As is the case under wholesale competition, electric transmission and distribution services would remain regulated monopolies, and would be required to transmit the power from the generating units to the customers. How these complex power flows would be coordinated under a direct access scenario is also the subject of intense disagreement and debate. The key question, then, that arises with respect to retail competition is whether, on an incremental basis relative to various alternative wholesale competition scenarios, it will enhance or harm both the technical efficiency of the electric system and the economic efficiency of pricing.

II.A Clarity of Objectives

To provide an appropriate context for thinking about the details of electricity restructuring, which are very complex, policy makers should first think about the relevant problems that they are trying to solve, and the objectives and principles that they are trying to achieve. It is essential that regulators and legislators clearly identify the problems with the current industry structure and/or the current regulatory practices used in the electric utility industry, as well as the underlying causes for these problems. Once these problematic factors have been identified, regulators and legislators should establish a clear set of objectives which they believe should be met in a restructured electric utility industry. They should also establish a set of key principles which should be upheld both during the process of reforming the industry, as well as in the long run, after the reform is complete.

For example, the Illinois Consumer Utility Board has proposed ten principles in "Interdependent Principles for Introducing Retail Competition into the Illinois Electricity Marketplace: 1) customer choice must be allowed only where effectively competitive markets are feasible, 2) where effectively competitive markets do not, cannot, or should not exist, services must remain under some form of regulation, 3) public policy goals of equity, universality, affordability, reliability, efficiency (both supply- and demand-side) and environmental protection must be maintained, 4) all customer classes must be able to participate in the competitive market, 5) restructuring of the industry must provide immediate rate relief to all customers, 6) all participants in competitive markets must share in the costs of building a competitive market infrastructure, including the costs of eliminating barriers to entry and to participation for small customers, 7) only participants in the competitive markets, and not customers without competitive options, must share in any stranded cost subsidy, 8) all participants in competitive markets must share in the costs of programs that benefit the public interest, 9) all electricity service components must be priced individually and on a non-discriminatory and equitable basis, and 10) generation must be divested from transmission and distribution into an unaffiliated entity."
Together, these objectives and principles should provide a framework and a context for evaluating the merits of specific restructuring proposals aimed at trying to solve the problems identified with the current structure. Real world considerations (e.g., generation market failures) and the unique characteristics of the electric industry which could interfere with or alter desired outcomes, must also be recognized and addressed. The evaluation must determine if a specific proposal will be more effective in achieving the stated objectives than either continuation of the status quo, or an alternative restructuring proposal. Use of this "big picture" evaluation perspective is particularly important in terms of identifying the potential long-term implications of various restructuring proposals and alternative ratemaking proposals on a step-by-step basis. Presumably, we do not want to restructure the electric industry one way today only to discover in a few years that another type of restructuring is needed, or that we rushed into a structure with unjustifiably high risks to consumers.

The importance of fundamental public policy objectives should not diminish under any restructuring proposal. One of the primary objectives of regulating the prices of electric services in the past has been to ensure reliable service at stable and reasonable rates. As noted previously, "reasonable rates" may not equal the lowest possible rates, given that regulators often try to enhance economic efficiency even if the result is higher rates. But the goal of stable rates has generally been achieved in most cases under the current cost-of-service regulatory approach. The one thing we can be sure of is that rates will be much less stable if generation is deregulated. The behavior of the world oil markets over the last 25 years illustrates this point quite well.

In addition, regulation has attempted to help achieve various state and national public policy goals related to equity, environmental quality, economic development and energy security. Equity is a concept that is both difficult to define and to achieve. In the case of restructuring, equity considerations can arise in the regulatory treatment of the costs of existing purchased power contracts and of uneconomic costs of generation in ratebase (strandable costs). Equity between customer classes and among individual customers within a class is also an important concern in designing electric rates. Equity arguments can (and have) been made on various sides of the same issue. For shareholders, "equity" may require that recovery of all prudently incurred costs be guaranteed, while for customers "equity" requires that they do not bear all of the costs of uneconomical generating capacity. Similarly, "equity" to one customer may be perceived as a "subsidy" to another. Sustainability of the environment is also an important objective of public policy, quite apart from low electric rates, economic efficiency and equity. While also difficult to define precisely, and challenging to implement in specific policy contexts (e.g., state regulation and legislation regarding electric industry restructuring), the long-run sustainability of our ecological support-systems is of fundamental importance, and must be considered when restructuring is debated. In short, state and national public policy goals operate as constraints on the extent and form of restructuring implemented in any particular state or region.

II.B Approaches to Making Tradeoffs
In evaluating particular restructuring options, we will, of course, face difficult tradeoffs between conflicting objectives. One example familiar to utility regulators is the positive effect of cost-effective demand-side management programs on the efficiency of resource use and on program participants' electric bills, versus the negative impact of small increase in electricity prices that may be caused by such programs. Another familiar example is the tradeoff between the benefits of pollution reduction and the impact of achieving that reduction on electricity prices.

Formulated as mathematical optimization problems, there are two general approaches to maximizing economic efficiency. One might attempt to optimize a single objective function (e.g., lowest present value of costs) subject to various constraints (e.g., a cap on air emissions). Alternatively, multiple objectives may be combined in a single measure of all important factors (e.g., "social costs" including direct and external costs). Either way, there are difficult decisions to be made. With the first approach, appropriate levels for the social policy-based constraints must be determined. With the second, appropriate "weighting factors" are necessary for combining various objectives into, for example, an index or dollar values. Often there are also tradeoffs between more certain and more uncertain electric prices, and thus policy makers will have to determine how much risk consumers will be willing to bear. For example, under retail competition, would consumers mind if their electric bills went up or down 20 percent from year to year if, on average, they were 5 percent lower than under regulation? Finally, when trying to determine the role that competitive markets for generation resources can play in enhancing economic efficiency, it is critical to remember that the possibility that owners of generation will be able to exercise market power is another type of trade-off that must always be analyzed. As part of analyzing the potential for market power, one must also analyze the degree to which market barriers exist, and how they can be minimized. This will likely be different under retail and wholesale competition scenarios.

Ultimately, there is no easy way around the difficult choices that electric industry restructuring will present. Fortunately, regulators and legislators are experienced in making tradeoffs between conflicting objectives. Here we offer no special insight, only a reminder that in the context of electricity restructuring it is important to articulate and prioritize the objectives and principles clearly and early in the process, and to inform the consideration of any tradeoffs with quantitative estimates of the effects. Tradeoff decisions can appear quite arbitrary if made in the abstract. On the other hand, with rough magnitudes in mind, it may be a simple matter to decide, for example, that a 1 percent increase in rates is acceptable in order to realize a 5 percent reduction in energy bills or a 5 percent reduction in pollution. Ultimately, the bottom-line tradeoff is whether the potential costs and risks of each aspect of restructuring are worth the potential benefits on an incremental basis. It is our hope that this report on the costs and benefits of electric industry restructuring will contribute toward an informed dialogue on the opportunities, risks, and tradeoffs involved in this enterprise.

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19 Monetization of non-monetary objectives is a particular form of weighting.
III. POTENTIAL ECONOMIC EFFECTS OF RESTRUCTURING

III.A Introduction

In this section of the report, we discuss the potential economic effects of electric industry restructuring. In particular, we define or describe each effect; explain how each relates to electric rates and economic efficiency, both narrowly and broadly defined; comment on the potential magnitude of each; and, where possible, identify the time frame during which each effect is likely to last.

Three categories of the impact of restructuring will be addressed. First, we will discuss stranded costs and the rate treatment thereof. Because stranded costs are sunk costs that have already been incurred, they are not new or incremental costs that will be incurred due to restructuring. Therefore, stranded costs should not be included in an incremental cost-benefit analysis of restructuring, but how they will be allocated among ratepayers and utility shareholders will need to be addressed as part of restructuring. To the stockholders involved, given prior explicit or implicit regulatory decisions, stranded cost recovery is primarily a matter of equitable treatment. However, it also can have an efficiency dimension in that the treatment of stranded costs may, in particular situations, contribute to rates that end up above or below an economically efficient level.

Next we will focus on stranded benefits. These involve programs for low-income customers, investment in research and development, DSM programs, attention to resource diversity, and environmental quality.

Finally, we will address a wide range of potential market responses to deregulation. These include the pressure on companies to cut costs in both efficient and inefficient ways, and in socially beneficial and socially destructive ways, the opportunity to offer additional services and rate options, the impact of increased risk on the cost of capital for generation, the potential for anti-competitive behavior among generation owners and aggregators that would erect market barriers, and the opportunity to realize greater power system operating efficiencies under enhanced competition.

Some of the economic impacts of restructuring are positive, some are negative (relative to various goals) and many are ambiguous or uncertain. Further research has the potential to help, in some cases, to reduce the uncertainty, but to a large extent we will have to gain practical experience with deregulation to see whether and where the market will deliver improvements or produce problems relative to the current system of utility regulation.
III.B Stranded Costs

III.B.1 Description/Definition of Stranded Costs

Stranded costs, also referred to as "stranded investments" or "transition costs," can be defined as the difference between the competitive market value and the regulated book value of a utility's electric generation assets. In other words, stranded costs represent the uneconomic portion of a utility's generation assets. The generic stranded cost formula can be written in an over-simplified manner as follows:

\[
\text{Stranded costs} = (\text{depreciated book value of generation assets}) - (\text{competitive market value of generation assets})
\]

Uneconomic costs associated with a utility's generation assets are presently part of its regulated embedded costs of service, and, therefore, they are currently recovered through the rates paid by all retail customers. As such, these uneconomic costs are not yet "stranded." Rather, they are "strandable," and would only become "stranded" if the utility were to price its generation services at market value, or if customers were to purchase electric generation from another supplier other than their local utility (this is referred to as retail competition).

Some costs associated with electric generation investments could become stranded under two scenarios, which are not mutually exclusive. The first scenario is one in which an existing vertically integrated utility sells one or more of its electric generation facilities to an independent third party. According to economic theory and good regulatory practice, the sale of a generation asset should occur at "fair market value." If this market price is less than the undepreciated cost of the facility in the utility's ratebase, the cost differential (or shortfall) is a stranded cost.

The second scenario under which the costs associated with electric generation investments could become stranded is one where a retail customer elects direct access to another source of generation. If the local vertically integrated utility had acquired a specific amount of generation resources in anticipation of serving the requirements of the retail customer who switches to direct access, the costs associated with the resources that would have served the customer become stranded. These stranded costs can be "mitigated" only to the extent that the "stranded resources" themselves, or the services they produce, can be sold to someone else.

In addition, the transition toward deregulation can itself involve costs (administrative, legal and technical) that may ultimately be stranded. For example, a considerable amount of time on behalf of stakeholders has already been, and will continue to be, spent on developing and implementing restructuring proposals. It is unclear whether, and if so how, such costs will be recovered from ratepayers. ELCON's eighth principle for achieving competitive, efficient, and equitable retail electricity markets is that "the potential for transition costs should not be used as an excuse to prevent

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20 Some restructuring proposals call for complete divestiture of generation ownership from transmission, and distribution ownership. This has the advantage of providing a clear basis for the market value unless market power becomes a significant factor.
or delay the onset of a competitive electricity market." We agree that they should not be used as an excuse, per se, but if transition costs coupled with other market transaction costs outweigh the potential benefits of a given restructuring model, then regulators and legislators may legitimately question that particular approach.

Generation costs which can become stranded (i.e., "strandable" or uneconomic costs) are, by definition, the costs above the market price for generation over some specified period of time. According to the theory of competitive markets, the uneconomic costs of a given producer of a service can not be passed through to consumers since consumers will not pay a price above market. Thus, under economically efficient conditions in a competitive market, a producer of that service will be forced to absorb all uneconomic costs. If such costs are recurrent, the producer will go out of business.

Once stranded costs are quantified, then a significant regulatory issue arises, namely how should they be shared between customers and utility stockholders. Many stakeholders in the electric industry restructuring debate agree that utility stockholders should not bear the entire burden of stranded costs. Proponents of this position refer to the "regulatory compact," namely the "bargain" between electric utilities and their regulators that as compensation for the "burden" of being regulated, utilities shall be guaranteed recovery of all prudently incurred investments. The line of reasoning follows that, since the majority of expenditures that led to stranded costs were made at a time when utilities were operating in a regulated environment, utilities should not alone be penalized merely because the business environment has been changed by regulators or legislators. Hence, many utility stakeholders believe that stranded costs should be shared by customers and stockholders, though opinions differ on their allocation between shareholders and ratepayers (e.g., 100 percent, 50/50, 20/80, etc.).

### III.B.2 Stranded Costs Relative to Rates and Economic Efficiency

The impact that stranded costs will have on future rates will depend on the amount of stranded costs that utilities are allowed to continue to recover from customers. Whether or not a utility is allowed to continue to recover certain stranded costs from customers, and to what degree these stranded costs should be shared between customers and utility stockholders, will depend on whether regulators deem that the costs were prudent and "used and useful" at the time they were made and the extent to which such cost differences are attributable to restructuring. For example, stranded costs which result from a retail customer electing direct access are more likely to be recoverable if the utility invested in least-cost resources at a time when direct access was not an option for that retail customer (i.e., at a time when it was reasonable for the utility to assume that it would have to serve that customer).^23

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^22 Stranded costs which cannot be recovered from customers would be "paid by" shareholders, in the sense that they would receive lower profits than they would have otherwise.

^23 It is important to note that if utilities are allowed to recover from current or former customers the difference between the book value of an asset and that asset's lower market value, then customers should receive payments equal to the appreciated value of any asset whose current book value is below market value." [Retail Competition in the U.S. Electricity Industry: Eight Principles for Achieving Competitive, Efficient and Equitable Retail Electricity Markets](https://www.energy.gov/laws/pdfs/r_55666.pdf). The Electricity Consumers Resource Council. Washington, D.C., June
"Recoverable" stranded costs can be continued to be collected either over time as part of an unavoidable distribution system charge on a cents per kWh basis, or through a one-time exit fee. The charge should be administered at the distribution level because all customers taking electric service will continue to use the local distribution system, and thus they will not be able to avoid paying their "fair share"\textsuperscript{24} of stranded costs. By design, a one-time exit fee will not impact future rates at all, though it will certainly impact the total cost to a departing customer of buying power elsewhere. Customers will include the fee as a direct cost in their assessment of the costs and benefits of switching to a new supplier.

### III.B.3 Potential Magnitude of Stranded Costs

Stranded costs can be calculated as the difference between the market prices for capacity and energy necessary to meet a utility's load, and the generation component of the utility's total revenue requirement under traditional embedded cost ratemaking necessary to meet a utility's load. Under this approach, stranded costs for a utility are based on a net system basis over some fairly long time period. The lifetime of each plant can be automatically incorporated into the analysis thereby accounting for the depreciation schedule of each plant, as well as respective long-term benefits that may result after a time when the market price exceeds a utility's embedded costs. In other words, this approach accounts for the fact that over a given period, both market and utility energy prices will likely escalate, and generation assets will depreciate, thereby lowering a utility's fixed embedded generation costs over the period, and thus tending to reduce the extent of strandable costs.

The total amount of stranded costs for any particular utility or for the industry as a whole is very sensitive to the market price for generation at the load factor of that utility. For example, the data plotted in Figure 3 provides a sense of the distribution of stranded costs for U.S. utilities, and also shows the importance of the market price. The step curve, increasing from left to right in the graph represents the cost of generation by utility.\textsuperscript{25} The horizontal line represents the cost of new generation, a proxy for the market price at the time that new generation is needed to serve demand (region-specific considerations in market price are ignored in this graphical depiction of U.S. stranded costs). At a 4.9 cent per kWh\textsuperscript{26} market value, the total stranded costs for U.S. investor-owned utilities amounted to approximately $13 billion \textit{per year} in 1993. This will tend to decline over time. At a lower market value the stranded costs would be much higher.

\textsuperscript{24} The stranded costs caused by a customer electing direct access could be recovered only from that customer, shared between that customer and other customers who have direct access as an option, or shared between that customer and all customers including those who do not have direct access as an option.

\textsuperscript{25} Actually, the data presented here is based on the average industrial rate by utility. For many of the utilities shown, we have estimated the unbundled generation prices based upon utility-specific financial information, and have determined that the average industrial rate is, in general, a good proxy for the unbundled generation price.

\textsuperscript{26} This value is in levelized 1993 dollars, based on a 15-year period, and reflects a load factor of 60% and 20% reserve margin. The value also includes the effect of losses and the costs of transmission for the industrial sector in order to be comparable to the utility-specific data. Data was obtained from the \textit{Technical Assessment Guide (TAG)}, Electric Power Research Institute (EPRI), Volume 1, June 1993. Note that gas CC units may have fallen in price since 1993.
III.B.4 Time Frame for Calculation and Recovery of Stranded Costs

Stranded cost estimates can be very sensitive to the time period over which they are calculated. This is illustrated in Figure 4, below, where we consider stranded costs for one utility system. For this company, embedded cost rates are significantly above current market value (at time $T_0$), but are expected to decline somewhat over time due to depreciation and no immediate need for new plant additions. Market prices, on the other hand, start low due to excess capacity, but are likely to increase due to both inflation and due to the regional surplus capacity situation tightening.
<figure 4: STRNDCST.BMP (Bitmap in Paintbrush)>
If stranded costs are calculated from the point at which competition starts, T1, through the point at which the market price trajectory crosses the embedded cost trajectory, T2, then the stranded costs will be reflected by area B in the diagram. However, the period of negative stranded costs beyond time T2 should also be figured into the calculation. If the stranded costs calculation is extended to an arbitrary endpoint, T3, then the net stranded costs will amount to area B minus area C (on a present value basis), which could even be less than zero (no stranded costs). It is entirely possible that for many systems that currently appear to have stranded costs, if the calculation is done over a reasonably long period, then the stranded costs may actually be zero or negative. In such cases, ratepayers may be entitled to a credit for the value of existing generating facilities as part of a transition to competition.

In order to provide a fair estimate of stranded costs, then, it is essential that the calculation is not limited to a near-term period in which annual stranded costs are positive if the generation assets have much longer lifetimes. However, it should be noted that the calculation of net stranded costs is not entirely open ended. First of all, the asset will have a fixed life. Secondly, the discount rate used for present valuing is quite effective at reducing the relative importance of the results for the later years, so that as uncertainty in the projections increases over the calculation period, the weight given to the annual figures decreases significantly. Also, the embedded cost and market cost lines may (or may not) merge over the long-term.

This figure also illustrates the importance of the assumed starting point for calculation of stranded costs. If our hypothetical utility recovers embedded costs until time T2, the point at which competition is declared to begin, then it will have already recovered the costs represented by area A. For any delay in the start of competition, the stranded costs represented by area B will decrease. With area B having a roughly triangular shape, even a short delay in the introduction of competition can result in a substantial reduction in stranded costs. A delay in the introduction of competition to the crossover point would eliminate the positive portion of stranded costs altogether, but the negative area may still be important to take into account when calculating the costs and benefits of restructuring. Negative stranded costs will show up as a net cost of restructuring, since it is a potential benefit to ratepayers that would be lost under competition.

III.C Stranded Benefits

III.C.1 Stranded Benefits and Their Relationship to Rates and Economic Efficiency

As stated earlier, the intention of electric utility regulation has been to enhance economic efficiency and to help achieve various state and national public policy goals related to energy security, environmental quality, economic development and equity. Under wholesale competition, regulation would be reduced somewhat, depending on exactly what policies are adopted, and under retail competition, it would be reduced significantly. Absent explicit policies in restructuring models to continue public policy goals, the displacement of electric regulation by market forces will lead to

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27 For example, a five percent discount rate implies that a dollar twenty years hence is worth only 31 cents today.
buyers, sellers, and intermediaries attempting to maximize their individual welfare at the likely expense of society's welfare. This will likely result in "stranded" benefits in a number of areas, as outlined below:

**Demand-Side Management (DSM) Programs.** DSM programs which are cost-effective from either a total resource cost perspective or a societal cost perspective will, in the long run, increase the efficiency of usage of electric appliances/technologies, reduce electricity consumption, lower average customers' bills, and provide net benefits to the electric system in the form of reduced pollution and delayed/avoided construction of infrastructure along with its social impact. This is an improvement in technical efficiency, primarily in the long-term. However, DSM programs impose some up-front costs which can be paid directly by only those customers who participate in the programs and/or indirectly by all customers in given rate classes through including some of the costs in the utility's ratebase. When the former approach is used, rates will not be affected; when the latter approach is used, short-term rates will rise though long-term bills will fall. Since individual buyers and sellers, who may have very high discount rates, attempt to maximize their welfare in the short run, and tend to overlook long-run net benefits, they will not be likely to choose DSM resources in a competitive market, unless the payback period is quite rapid. The long-run net benefits of DSM to the electric system, as well as to society, will thus be stranded. It is important to note, that the stranded benefits from DSM (i.e., lower bills resulting from lower consumption) are likely to be at least as great as, if not much greater than, the potential benefits from competition (i.e., lower bills resulting from lower rates in all years). This is why not stranding DSM benefits is a crucial issue in restructuring.

**Low-Income Residential Programs.** Low-income residential programs provide participants with financial assistance, special rates, leveled payment options, and/or free weatherization/retrofitting so that they can avoid falling behind on payment of their electric bills. In the absence of such assistance, these customers may face health and safety risks (e.g., lack of heat), which in turn could impose substantial costs on society (e.g., in trying to keep warm, the resident causes a fire). Under regulation, the costs of these programs are recovered from all customers. Even though the incremental effect on rates is small, without a policy decision to maintain these programs, retail competition is likely to lead to the elimination of these programs, and their benefits will be stranded. It is also likely that the need for low-income assistance will increase with deregulation, as the negative implications of restructuring may disproportionately fall upon low-income customers.

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28 A DSM program can either be designed to reduce the total amount of power demanded by customers or to shift the time of day when some customers demand power.
29 The total resource costs / benefits of a DSM program include both the participants' and the utility's costs and benefits.
30 The societal costs / benefits of a DSM program include the participants' and the utility's costs, as well as positive and negative externalities.
33 Some consumer advocates are concerned about the issue of "customer of last resort", namely the customer to whom retail suppliers do not and will not market because the customer lacks market power. This market power is usually a function of the size of the customer's demand and disposable income. (Brockway, Nancy. *Deregulation of The Electric Utility Retail Market: Implications for...*
Research & Development (R&D). In the electric utility industry, R&D typically centers around improving the performance of, increasing the efficiency of, lowering the costs of, and/or creating new technologies which either produce or consume electricity. Economic theory often points to technological improvements as important sources of economic efficiency gains. These benefits accrue over time but require an up-front investment which some utilities currently fund, in part, with ratepayer money. In an attempt to lower rates, utilities in competitive markets may eliminate ratepayer funding of R&D to the norm of economic efficiency in the long run.

Diversity in the Resource Mix. An appropriately diverse resource mix is likely to include electric generating plants (i.e., "supply-side" resources) fueled by coal, natural gas, oil, hydro, wind, biomass, and/or nuclear, as well as a variety of DSM programs (i.e., "demand-side" resources). A diverse resource mix may not be the absolute least cost mix, and thus may not yield the lowest possible rate, but it provides a hedge against risks such as a particular fuel price increasing substantially, the reliability of a plant decreasing, or a new pollution tax (such as a carbon tax) being introduced. However, in a competitive generation market where suppliers and consumers are focused on obtaining the least cost mix in the near-term, all suppliers will tend to procure only the least-cost resource(s). Hence, diversity in the resource mix is likely to be reduced under more or rigorous competition, unless policies like resource portfolio standards are put into place.

Environmental Quality. The production and consumption of electricity substantially impacts the environment by means of air and water pollution, land degradation, and natural resource depletion. When the costs associated with these environmental damages are not reflected in the price of electricity, environmental "externalities" result. Regulators in some states have required utilities to "internalize" the costs of environmental externalities by adopting monetized externality values for planning purposes. As noted above, internalizing these costs increases economic efficiency, broadly defined, but it also increases electric rates. In the absence of specific regulation or environmental taxes, these externalities will definitely not be taken into account in the competitive electricity market, and the quality of the environment will deteriorate. With competition limited to the wholesale level, many externalities policies could be implemented in the regulation of distribution company resource procurement, just as some states do today. With retail competition, other approaches (e.g., emissions caps with trading, environmental taxes) are necessary to internalize environmental externalities. These latter policies probably require legislation.

Captive Customers, and Options for Mitigation. National Consumer Law Center, Boston MA, June 4, 1995.)

34 For example, utilities may fund R&D in renewable energy facilities (e.g., wind turbines) or in high efficiency end-use appliances (e.g., high efficiency electric water heaters).

35 As an example, the chairman Stan Skinner of Pacific Gas & Electric recently stated, “We can no longer justify the use of shareholder or customer money for the development of renewable energy facilities. Therefore, we have substantially reduced our research and development efforts in this area”. “Citing Costs, PG&E Shifts Policy To Limit Renewables, Stress EVs”, Utility Environment Report, September 29, 1995: p.5.

Renewable resources relate to several of the categories discussed above, but deserve specific mention. They benefit from RD&D funding, and they provide resource diversity and environmental benefits. Relative to fossil-fuel generating technologies, many renewables tend to require higher up-front investment, but have lower operating costs. Also, many renewables many still be many years from commercial maturity. If restructuring is done in a way that shifts the focus of decision-making even more toward short-term returns, then the development and implementation of renewable generating technologies will suffer greatly. One policy approach is to fund renewable RD&D and/or currently above market costs of renewable resources through a systems benefits charge. Alternatively, a resource portfolio requirement could provide for a specified minimum amount of renewable resources in the mix, perhaps with trading of credits to provide for a least-cost approach. It is important to note that this policy would not require a separate charge.

III.C.2 Potential Magnitude of Stranded Benefits

Current levels of spending on programs that could be stranded under restructuring vary widely by utility system. Utility spending on DSM totaled about $2.8 billion in 1993 (EIA, 1993). Data for 1992 puts utility spending on low-income weatherization programs at about $140 million. There are a variety of other utility efforts to assist low-income customers for which we do not have reliable national cost data. Utility spending on RD&D has been estimated at 0.3 percent of revenue, putting the figure at about $500 million per year. "Expenditures for environmental protection" for investor-owned utilities in 1993 have been reported at $2.9 billion on utility FERC Form No. 1 filings. These figures give a ballpark sense of current spending on potentially "stranded benefits" programs ($6.3 billion) -- presumably, the benefits of such programs to society are much larger.

Of course, none of these "stranded benefits" need be stranded in any restructuring scenario. Continued realization of the benefits will, however, require that specific provisions for these programs be included in the "restructuring package." If stranded benefits programs were discontinued immediately, the time frame for the social impacts would vary from immediate hardship (low-income assistance programs) to lost technology opportunities a decade or more in the future (RD&D), to cumulative environmental impacts lasting for decades.

III.D Market Response To Increased Competition for Electric Generation

Below, we discuss the ways in which the electricity industry might respond to competition for generating resources both in wholesale and retail competitive scenarios.

III.D.1 Cost-Cutting Responses

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37 Hamrin, et al., 1994, p. 44.
38 Compiled in EIA 1995.
Suppliers of generation may succeed in minimizing their short-run costs, particularly labor costs, in order to lower their rates and attract customers. Generation-related O&M costs might be reduced through worker lay-offs and/or through a decrease in either routine plant maintenance expenditures and/or longer-term capital additions. However, Richard Cudahy, in writing about "the social cost of economic efficiency," points out that:

<Q> The cost calculus of deregulation often overlooks the pain of dislocation. I think the public may be as much concerned with the loss of tens of thousands of jobs on the failed airlines, not to mention personnel cutbacks by other deregulated businesses like the long distance telephone companies, as with the hope for bargains in fairs and other rates. . . In times of job loss, the citizen as "consumer" may once more begin to take second place to the citizen as "producer" [i.e., as a worker].

Many electric utilities are already beginning to reduce staff levels in anticipation of increased competition. For example, during a single week in October 1995, announcements came from Duke Power, Commonwealth Edison, and Washington Public Power Supply System that the utilities will cut, respectively, 900 positions over the next five and half months, 3,000 jobs over the next two years, and 200 employees over the next ten months.

A week later it was announced that the merger of Puget Sound Power & Light and Washington Energy Company "is expected to generate savings of $370 million over 10 years, with 45 percent of the savings coming from a reduction of 300 persons or 8 percent of the combined workforce." All of the companies involved indicate that the elimination of jobs is an effort to reduce their costs and improve their competitive positions. In the United Kingdom, the privatization of the electric industry resulted in the immediate elimination of many electric sector jobs and more than two hundred thousand jobs in the coal industry, which had been heavily subsidized prior to privatization.

On the one hand, trimming "fat" from utility systems is an intended and direct benefit of deregulation, though perhaps competition is not necessary to achieve these savings. PBR approaches to regulation might achieve the same goals. As discussed above, the "technical efficiency" of the industry is improved by producing more output with less input, and labor may be considered as just another type of input. On the other hand, it may be important to recognize that some efficiency improvements do not leave everyone better off, and state policy goals may legitimately include considerations beyond simple economic efficiency, such as promoting local employment. Also, providing for retraining and job placement services might be included as a component of a restructuring package if large numbers of layoffs are expected.

With regard to achievable reductions in plant maintenance costs due to competition, it is important not to allow the immediate cost savings to be offset by the costs of deteriorated plant performance in the mid- to long-term, with poorer system reliability leading to more blackouts, or, at least, to higher costs for replacement power later. Nor should immediate cost-savings come at the expense of lower quality

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customer service (e.g., response time for taking care of problems). For example, many utilities have already started to reduce operation and maintenance (O&M) costs and capital improvement expenditures at operating nuclear units in anticipation of increasing competition and to minimize stranded costs. "The ability of utilities to achieve and sustain reduced operating costs in future years will depend to a significant degree on how well they manage the cost impact of current technical problems and those currently unknown technical problems that will be encountered as operating nuclear units age." Nuclear Regulatory Commission Chairman Ivan Selin has stated that pressure from competition "may lead to significant safety concerns" and that some utilities might attempt to "cut corners" or be tempted to "put off capital investments which we consider necessary to maintain equipment in top shape." This may also lead to higher injury rates among plant workers.

In summary, assuming that generation operation and maintenance cost reductions are passed through to consumers if competition increases, electric rates will fall. The Wisconsin PSC has estimated that plant O&M cost reductions could be about 15 percent. This could reduce total generation costs by about 5 percent. However, there will be gains in economic efficiency only to the extent that generation costs are reduced without sacrificing the availability and reliability of the power supply system, and without threatening the health and safety of workers, consumers, and the environment. If generation costs are reduced at the expense of reliability, health, and safety, electric rates will still fall in the short run but economic efficiency may also decline. Furthermore, this approach to lowering short-run labor costs might not be viable in the long run, since plants may ultimately need more expensive repairs, or they may need to be shut down and replaced if they begin to have a negative impact on the electric system, and customers may not be satisfied with the quality of service.

III.D.2 Sales Promotion

Deregulated generation and aggregation companies will attempt to increase their kilowatt-hour sales relative to when they were regulated, both through selling more electricity to existing customers, and through attracting new customers. We already see innovative utility marketing efforts such as the use of "bonus points" to reward customers for using electricity or switching to electrical appliances (the points can then be used to "buy" additional electricity-consuming equipment). A larger sales base will allow an aggregated company to spread its existing fixed costs over more output, therefore reducing short-term prices to customers. This may also be true for distribution companies. While they will still be regulated, they may find it desirable to be able to lower their average costs in order to maximize profits, e.g. under a PBR scheme. However, at some point in time the increased sales will require the earlier procurement of additional generating resources, or distribution/transmission system investments. This could tend to raise rates, if the marginal costs of new equipment is above the average depreciated cost of existing equipment. Furthermore, increased sales may also increase pollution and other environmental impacts, thereby decreasing economic efficiency.

III.D.3 Additional Services and Rate Options

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43 September 8, 1994 Press Conference.
One of the essential conceptual elements in the restructuring process is for utilities to provide, and price, their major distinct services to all customers on an unbundled basis. Therefore, electric generation, transmission, distribution, DSM, ancillary and customer services should be provided, and priced, separately. Unbundling should allow all comparably situated customers receiving the same type and quality of service from a given provider to pay the same rate for that specific service,\footnote{The concept of "comparable service" has been a key point in FERC's policy statements regarding competition in the gas and electric industries.} and should allow everyone to acquire the specific level and mix of services they need, based on the same tariffs. To the extent that the current services and pricing options do not meet customers’ needs and preferences, providers will have the latitude, and presumably, the incentive, to respond to these demands by creating new services and rate options, so that customers only pay for what they need. This is especially true under retail competition.

Expanded service options for customers is one of the key rationales for introducing competition into the retail electricity market. Some existing services may be offered at various gradations of quality and reliability; however, for most services little variation from the quality of services currently being offered may be available. New services may also be created, though it is unclear at this time what these services might be, nor whether a significant number of customers want them. They may not even be electricity services, but rather services which simply use the electric distribution system in some way, such as video, telephone, Internet, etc. In terms of economic efficiency, offering a wider range of services could increase the cost of some of the previously existing services, depending on how "joint" or "common" costs are allocated. If there are cross-subsidies among services, then the economic efficiency of electric usage could be reduced, and restructuring could have negative effects.

On the positive side, distribution utilities or aggregators could experience significant "economies of scope" such that economic efficiency could be improved by offering more services and/or by utilizing existing or new capital equipment more efficiently, i.e., at higher load factors.

Many utilities are already offering a wide array of special rate options to their large customers. These include load retention rates, economic development rates, guaranteed rates, indexed rates, interruptible and reliability-specific rates, surplus power rates, time-of-use rates, and real-time pricing (RTP). While such rates can be, indeed have been, offered by electric utilities prior to restructuring on a bundled basis, moving toward competition will tend to increase the pressure for special rates, and provide the flexibility for companies to offer them. Special rates can, of course, discriminate against those customers who do not have the power to negotiate with generation suppliers. The power to negotiate is usually a function of the size of the customer's demand and disposable income.

Some of the rate options have been explicitly discounted relative to actual costs in order to promote specific societal goals (e.g., employment creation) or strategic utility objectives (e.g., discouraging customer departure). Some utilities have requested permission to negotiate "special," or flexible, rates with large users without the need for Commission approval in order to retain existing customers who might self-generate or obtain cheaper power elsewhere, or to attract new customers for the same reasons. Proponents argue that these discounted rates are in the best interest of all customers because they would benefit from having fixed costs reduced by retaining existing large users and attracting...
new large customers. This is true if "uneconomic bypass" is avoided.\textsuperscript{45} Furthermore, with explicitly discounted rates, the equity issues that arise can be addressed in a straightforward manner.

In contrast, other rate discounts are often not explicit (e.g., interruptible rates), and so the associated cross-subsidization issues are typically not addressed. For example, details of the ratemaking process can create hidden discounts due to improperly classified costs (i.e., between energy/variable and demand/fixed), or poor rate design methodologies. Real time pricing rates, usually justified on the basis of economic efficiency, often provide substantial discounts for customers, even in the absence of any price induced load shifting.

In short, negotiated rates, real time pricing, and interruptible rates, often have important roles in terms of discouraging uneconomic bypass, sending appropriate price signals, and encouraging efficient utility operations. They can also transfer costs to other customers and/or allow large customers to avoid paying for their share of fixed costs (including their share of stranded costs). However, it is important that all of the ratepayer implications of such rate designs are explicitly identified, and that non-participating customers do not pay discounts for rate designs that are of no benefit to them.

\textbf{III.D.4 Risk and Market Price Volatility}

One of the correctly perceived benefits of electric utility regulation in the past has been the lack of volatile electricity prices for most electric users. The ability to pay for electricity competes with spending in other areas of necessity such as housing, healthcare expenses, or capital improvements for personal or business purposes. Thus, predictable and stable electric rates allow people to budget for these and other essential expenditures. Even where electric rates are too high, they have been fairly stable from year to year, though in some places they have just increased steadily, especially from the mid-1980s to the mid-1990s.

Most regulated electricity prices are based on average embedded costs which consist of investments that have been incurred over a long period of time. As a result, cost-of-service based electricity rates have necessarily been relatively stable over long periods, except when major new power plant investments have been added to ratebase. Moreover, current ratemaking practice has tended to have standard fixed rates that do not vary over short time intervals (e.g., hours) or even months. Thus, these days, regulated rates typically only change every few years, when there is a rate case.

In contrast, competitive generation markets may show relatively rapid and substantial swings over both long and short time frames. New market entrants could help control these price swings, assuming they may have some type of long-term (5 years or more) contracts. However, in a year in which regional generating capacity becomes tight, the balance of supply and demand could cause a large jump in electricity prices for spot market purchases. On a short time scale, competitive markets can be expected to implement time-of-use and "real time" pricing, with prices changing hourly, or even more frequently. These prices could vary over a range of 10-15 cents per kWh (representative

\textsuperscript{45} Uneconomic bypass would occur if a retail customer's decision to purchase generation from a source other than its local utility resulted in net total resource costs, instead of benefits, to the utility and its remaining customers.
of the total cost of a combustion turbine required to meet a daily peak) to roughly 1-2 cents per kWh (representative of the operating cost of a base-load coal unit that might be on the margin in low load periods).\textsuperscript{46}

In short, market-based prices are likely to be more volatile than regulated prices, both on an hourly and on a seasonal basis, as they reflect actual swings in fuel costs, heat rates (i.e., plant efficiencies), and the weather, and as they respond to anticipated changes in input costs, taxes, politics, and a variety of other subjective perceptions of market participants. Because of this potential volatility, it is likely that financial and contractual instruments for risk reduction will become available (e.g., futures markets, fixed price contracts) for those willing to pay for them. Investing in these instruments could yield stable prices, but presumably at an additional cost to ratepayers. Brokers may offer fixed price options to customers, perhaps with known, specified prices over several years. Again, in a competitive market, this sort of price stability will come at an additional cost.

\textbf{III.D.5 Cost of Capital and Capital Structures}

Under traditional cost-of-service regulation, prudently incurred costs are generally recovered in prices. Under a deregulated generation market (under either wholesale or retail competition) where cost recovery would not be guaranteed, much more of the risk of new construction and of operating existing generation would be directly transferred to stockholders and removed from ratepayers. However, ultimately ratepayers will likely see the cost implications of this shift in risk. Regulated utilities finance new construction with capital structures containing about 35-40 percent common equity and 60-65 percent debt and preferred stock. A generation owner in a competitive market is more likely to finance new construction with capital structures of 60 percent to 80 percent common equity. This increase in the proportion of common equity would be associated with higher, but not guaranteed, equity returns to stockholders of these firms.

\textbf{<Q>} In general, the more capital intensive the generation technology, the more likely costs are to be higher... These higher overall costs for the various generating technologies in the competitive structure imply a potential for long-term electricity generation prices to increase... any tendency for long-term prices to increase would only be exacerbated if generating companies are able to wield market power.\textsuperscript{47}

In Table 1, this cost of capital effect is combined with several cost-cutting effects in an illustrative example based upon the Wisconsin Draft EIS. In this example, the levelized cost of a new gas combined-cycle plant owned by a utility is 4.2 cents per kWh, given standard assumptions for plant construction and operating costs and a conventional utility cost of capital and capital structure. In a competitive environment, with a shift toward more equity in the capital structure and a higher cost for that capital, the levelized cost increases to 4.6 cents per kWh, or a 10 percent increase due to this


factor alone. Any cost decreases that result from competition would then offset this increase. Here, following the assumption in the Wisconsin Draft EIS, we assume that capital construction costs are cut by 10 percent and operating costs are cut by 25 percent due to market pressures. The combined effect of the increase due to risk and the decrease due to construction and operating efficiencies is, in this example, a small net increase -- to 4.3 cents per kWh. The assumptions in this example are, of course, somewhat arbitrary. Depending upon the response of capital markets to competition and the effectiveness of managers in cutting costs, the net effect could be a substantial net increase or a substantial net decrease. We include the example here mainly to point out a way to think about this tradeoff, not to argue for a particular set of assumptions or a particular result.
Table 1
Illustrative Costs of New Generation
With Effects of Competition

<table>
<thead>
<tr>
<th>Levelized Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost of utility-owned facility under current regulation (9.2% weighted average cost of capital)</td>
</tr>
<tr>
<td>Increased cost of capital (to 12.4%)</td>
</tr>
<tr>
<td>Decreased construction and operating costs (10% and 25%, respectively)</td>
</tr>
<tr>
<td>Combined effect</td>
</tr>
</tbody>
</table>

Also, one of the often stated justifications for electricity restructuring is that the risk for mistakes can be borne by the market. While this is a reasonable objective, it is important to recognize that there is no "free lunch" -- investors will require higher returns to compensate for the increased risk. As a general matter, customers must either accept risk or pay to have the competing companies accept that risk.

Similarly, relative to regulated markets which operate assuming lower, more societally-oriented discount rates, unregulated markets operate assuming higher, more individually-oriented discount rates. Use of higher discount rates will also exacerbate the tendency to place greater emphasis on short-run costs and benefits, and, therefore, on lower short-run electric rates.

III.D.6Incentive to Innovate

In reviewing the deregulation experience of the telecommunications, airlines, natural gas, and railroads industries, Venture Associates has identified some common patterns. One of the patterns is that "as new markets emerge, and as new refinements of existing markets are discerned, the pace of technological change accelerates."48 Because innovation appears to establish a basis for market advantage, the authors conclude that the evolution of technology and deregulation are mutually reinforcing. The "innovation" can be in the packaging of services and pricing options (noted above), or in the supply system itself.

For example, proponents of electric industry restructuring claim that there are likely to be improvements in power plant design which either reduce costs or improve performance. A recent

report for NARUC identifies opportunities for improved power plant efficiencies, including the following:\n
**Improved operation techniques:**
- feedwater heating
- turbo-charged boilers
- adjustable speed drives
- operating at higher temperatures

**Retrofits:**
- turbine blade recoating
- seal replacement
- enhanced tubing
- efficient transformers

**New Plant Configurations:**
- combustion turbine-boiler combinations
- fluidized beds
- inlet air coolers on combustion turbines
- instrumentation and controls
- pulverizer upgrades
- waterwall tubing
- soot blowers

Arguably, the use of efficiency enhancing technologies will be accelerated by market pressures upon electricity suppliers. This will probably occur under both wholesale and retail competition. Presumably innovation will occur primarily where the innovators can capture the additional profits allowed by innovation for themselves. On the other hand, we note that many of the technologies listed above have been phasing into use over the last decade already, and that to the extent that restructuring causes decreases in electric utility RD&D expenditures or a higher cost of capital, the introduction of new capital intensive efficient technologies could be deterred. In fact, the complete deregulation of generation markets could allow for conditions under which old, inefficient plants would run more than previously. The market may simply value the capital assets lower than those of an efficient plant, to a sufficient degree to allow the total cost of power from the inefficient plant to be lower.

The role of technology innovation in driving the electric industry restructuring is worth examining. Improvements in combined-cycle technology resulting in higher fuel conversion efficiencies and lower capital costs are often cited as a major underlying reason for the shifting relationship between average electricity prices and marginal electricity costs, and hence the need to restructure the industry. Indeed, the numbers in Table 2, while perhaps a bit optimistic for 1996 and beyond, show a marked decline in capital cost and improvement in heat rate for gas combined-cycle units. Moreover, since

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the early 1980s combined-cycle technology has gone from pilot to mature status, and has become feasible in smaller increments of capacity. However, the power plant technology improvement is only part of the story, and not even the most important part. (See Figure 5.) Without the gas price decreases having occurred since the early 1980s, the levelized cost of gas combined-cycle generation would have decreased from about 10 cents per kWh in 1982 to about 8 cents per kWh in 1996. This would have been a significant but not large amount, and it would have left the marginal costs of new generation above the average cost of generation by the mid-1990s. In contrast, it is the decline in gas prices -- both actual and forecast (after 1996) -- that dominates the drop in gas combined-cycle generating costs. This fuel price decrease may itself be largely a matter of technological change, but the relevant innovations would have more to do with gas exploration techniques and horizontal drilling than advances in combustion turbines technology. Thus, we can see from Table 2 and Figure 5 that it is primarily the decline in natural gas prices that has shifted the relationship between average electricity prices and marginal electricity prices, in turn fostering the movement towards restructuring.

III.D.7Power System Operations

A power pool is an entity that coordinates electric utility operations to achieve transmission system stability and least-cost dispatch. Tight power pools, such as the New England Power Pool or the Pennsylvania-New Jersey-Maryland Power Pool, dispatch power plants centrally on the basis of variable operating cost, regardless of plant ownership, in order to realize overall system benefits for all generation owners. The net benefits of this joint economic dispatch are then allocated to the member companies according the terms of the pooling agreement. Thus, a tight power pool provides a win-win scenario, and could certainly be structured to accommodate and enhance competition.
<table 2: CC_TRAJ6.XLS (Excel 5.0)>
<figure 5: CC_TRAJ6.XLS (Excel 5.0)>
Looser mechanisms for coordinated operation (including economic energy exchange) can serve to realize a portion of the benefits of pooled dispatch without a formal power pool.

Many regions of the U.S. operate in a looser way than the tight power pools such as NEPOOL or PJM. Thus, some existing regional power pools may promote inefficiencies by failing to perform strict "economic dispatch" (least-cost dispatch of generating units based on variable costs only\(^{50}\)), as well as through failing to provide adequate transmission access for all owners of generation. Furthermore, some utilities may not be in power pools at all. A competitive electricity market could address these inefficiencies if the restructuring model were to incorporate the creation of large regional transmission groups (RTGs) and power pools, and the regulation of full open transmission access, as attempted under FERC Order No. 888. Furthermore, inefficiencies in transmission planning could be greatly reduced through transmission capacity optimization at this RTG level.

According to a 1981 FERC study, "the aggregate unrealized economies available through further [power pool] coordination to approach single-system regional planning and operation are probably not large -- perhaps of the order of 1 to 2 percent of electric revenues, on a national basis."\(^{51}\) Though the percentage may seem small, the impact could be significant when one considers the fact that in 1993 national electric operating revenues for U.S. investor-owned electric utilities equaled $176.4 billion.\(^{52}\) These 1981-based estimates are towards the low end of the range of savings that FERC recently projected for the impact of Order No. 888, which were about $3-5 billion per year.

One form of power "pooling" that has been proposed for competitive electricity markets (wholesale or retail) is the "poolco," in which suppliers bid hourly prices that serve as the basis for dispatch decisions. This approach to power pooling, which has been adopted in California by the PUC, and appear to be recommended by both Massachusetts and New York, could improve system efficiency if the bids were to reflect incremental running costs more accurately than the simple variable cost (fuel-based) formula used in tight power pools. If, however, bidding strategies are adopted which do not reflect hourly incremental costs, then generating units could be dispatched significantly out of their economic merit order. This could happen if bidders try to recover a significant amount of their economic fixed costs as part of their bid prices. One factor that greatly complicates the pricing behavior in a poolco is that the unregulated generation owners must take their need to recover fixed costs as well as variable costs into account when developing their hourly bids over the course of the year, and over the lifetime of the plants. As a result, both electricity prices and overall fuel usage would be economically inefficient in a poolco, and the hourly price signals to potential new competitors would be distorted. We believe that with a poolco, distorted dispatch is a significant concern which could be enhanced by the potential for abuse of market power by companies that remain vertically integrated or that control a large portion of the generation market. Thus, it is possible that the pricing structure of a poolco could strengthen any underlying ability of generation

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\(^{50}\) For power pool dispatch purposes "variable" costs typically include just fuel costs and variable O&M costs.


owners to exercise market power relative to a competitive market where buyers and sellers simply rely on bilateral contracts which are dispatched through a tight power pool.

III.E Market Power Issues

Because the issues of market failure and market power are so critical to whether or not electricity markets produce efficient outcomes, we must consider them in some detail here. After examining the characteristics of a perfectly competitive industry generally, we will look briefly at the relationship between concentration and price in other industries. Then, we will discuss specific electricity market structures (e.g., "poolco"). Finally, we will address the vertical market power issues that could impeded the realization of economic benefits from electricity restructuring.

III.E.1 Perfect Competition and Market Failure

There are four key characteristics of a perfectly competitive industry:

1. Firms attempt to maximize profits.
2. Transactions and market entrance are costless.
3. There are a large number of firms.
4. Firms are price takers.\(^5\)

An actual market structure for electric generation in a particular region should be evaluated against these four criteria in order to determine whether the industry is (or could be made to be) sufficiently competitive such that complete deregulation of generation would be feasible and desirable. There is no single, simple "bottom line" for such a complex evaluation. Rather, judgment will be required in deciding whether the circumstances warrant faith in market forces.

*Firms Attempt to Maximize Profits.* It is probably safe to assume that deregulated competitors in electricity markets will attempt to maximize their profits, and thus we will not elaborate on the point. We will simply point out that the methods incumbent firms might use (e.g., increase sales, cut costs) to try to achieve this goal could come at the expense of decreased economic efficiency (e.g. less DSM), insufficient reliability, poor environmental quality, etc.

*Transactions are Costless.* In a perfectly competitive market, transactions are the grease in the system, allowing resources to flow optimally. In practice, participants in a market may have significant transaction costs associated with collecting information, making decisions, negotiating contracts, addressing legal issues, advertising services, etc. If these costs are significant, then the imperfect market result may be far from efficient, and significant market barriers may exist for new competitors. Analyses of energy conservation investment decisions has shown rather convincingly that "market barriers" and "transaction costs" can be considerable in that context. A recent Tellus Institute analysis considered some of the transaction costs associated with electricity restructuring if retail competition

were the goal. The study found that metering costs for residential customers could amount to between $16 and $37 on an annualized basis per customer if real time pricing is required, and marketing costs could amount to at least $40 per customer "switched." Under such conditions, small usage residential customers could see an insurmountable market barrier to benefiting from retail competition. Similarly, the Wisconsin Commission staff's assessment of restructuring found that "increases in choice could create an increased burden of information gathering and confusion."55

There are a Large Number of Firms. The number of firms in a particular market is a key factor in determining whether the market is (or can become) competitive. In 1983, Joskow and Schmalensee conducted an analysis of the likely effectiveness of competition at the generation level in deregulated bulk power supply markets. Though that research is over ten years old, their findings and conclusions deserve consideration, since the passage of EPAct 1992 and FERC Order 888 may not change the fundamental principles underlying their conclusions. They focused on the extent to which supply was concentrated in the hands of a small number of firms, since "all else equal, noncompetitive [e.g., collusive] behavior is generally thought to be more likely the more concentrated a market is."56 Using 1978 data on plants which accounted for about 96 percent of U.S. electricity generation, the authors' analyses indicated that "the high concentration areas seem important enough to make it difficult, in the absence of further analysis, to justify going forward with nationwide deregulation of bulk power markets with no horizontal disintegration of existing holding companies."57 They pointed out that unless there are some substantial diseconomies associated with the operation of multiple generating plants which they were not aware of, then in the absence of forced horizontal disintegration, market forces will tend to increase existing firm-level concentration. However, even when Joskow and Schmalensee simulated complete horizontal disintegration, it did not suffice to eliminate all potential competitive problems.

The authors also concluded that the threat of entry by the construction of new capacity is not likely to be an important restraining influence on seller behavior in either the short- or the long run in generation markets. They point to the fact that it is unlikely that any entrepreneur would build a plant to meet regional load growth without a long-term power contract for the output. In attempting to secure such a contract, a potential entrant would have to compete against existing suppliers, since a potential buyer would presumably not sign a long-term contract with a newcomer without giving existing suppliers a chance to meet or beat the new offer. Furthermore, the potential entrant would have to clear the contract with the regional power pool, since "it is likely to be necessary for the power pool to take an active part in planning and guiding regional construction activity"58 in order to ensure least-cost supply. Joskow and Schmalensee suggested that generating entities already established in a region and involved in long-term relationships with a power pool and/or individual buyers could

54 Tellus Institute and Wisconsin Energy Conservation Corp. "Can We Get There from Here? The Challenge of Restructuring the Electricity Industry so that all can Benefit." Prepared for the Utility Consumers' Action Network. February, 1996.
57 Ibid.
58 Ibid.
have important advantages over potential new entrants in bidding to construct and operate new generating facilities. They conclude that long-term relationships tend to transform competitive bidding situations into oligopolistic\(^59\) and monopolistic situations.

Since the time of Joskow and Schmalensee's study of market power, conditions and options (including those of the authors of that study) have changed somewhat. A similarly comprehensive and thoughtful study of market power under today's conditions would be quite useful.

Recent calculations of market concentration in electricity generation show that for many regions the level of concentration is too high to provide for a sufficiently competitive market. For example, in NEPOOL the Herfindahl index\(^60\) is greater than 1900.

The Department of Justice and the Federal Trade Commission have guidelines for evaluating mergers, in which the Herfindahl index is a determining factor. Specifically for a level of concentration between a Herfindahl index of 1000 and 1800, the guidelines use the term "moderately concentrated," and state that in this range mergers "are unlikely to have adverse competitive consequences and ordinarily require no further analysis." Levels above 1800 are referred to as "highly concentrated" and create a presumption that such mergers are "likely to create or enhance [horizontal] market power or facilitate its exercise." Even at these high levels of concentration, a merger can be approved if it is shown that other factors make abuse of horizontal market power unlikely.\(^61\) However, it is also important to keep in mind that while widely used, the Herfindahl Index is a very simplistic measure of market concentration, and it does not attempt to capture the ways in which market power can actually be exercised in a particular market structure.

The current flurry of proposed electric utility mergers is troubling in light of these market concentration issues. One customer group has commented that "While the need for regulation [of generation prices] will decline, the role of antitrust laws for providing consumer protection should increase in importance."\(^62\) Unfortunately, the use of antitrust laws can be expensive, time consuming and ineffective, and primarily focuses on whether competitors have been harmed rather than on whether ratepayers have been harmed. In restructuring the electric industry, then, state and federal utility regulators should consider market power issues prior to restructuring, and build solutions and preventative measures directly into restructuring plans.

_Firms are Price Takers._ The key reason that market concentration is seen as a problem is that a large firm or group of firms that dominates a market can influence the market price. In a perfectly competitive industry, all firms make their production decisions based upon market prices determined

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\(^59\) An oligopoly is "an industry in which there are only a few sellers of the good in question" (Nicholson, 1985: p.758).

\(^60\) The Herfindahl index is calculated as the sum of the squares of the market shares (expressed as a percent) of the firms competing in the market. Thus, an industry with 10 firms of equal size would have a Herfindahl index of 1000.

\(^61\) Department of Justice and Federal Trade Commission. 1992 _Horizontal Merger Guidelines_.

by aggregate supply and demand. However, in real markets, concentration of ownership often leads to opportunities for firms to increase prices above "competitive" levels.

Leonard Weiss\textsuperscript{63} has examined the relationship between market concentration and price in many markets and has found that higher levels of concentration do indeed tend to correlate with higher prices. Weiss' summary of 121 data sets of concentration and price covering a wide range of industries (including airlines, banking, cement and many others) shows the results listed below, including a convincing majority of studies finding "positive" effects: higher levels of concentration resulting in higher market price.

\begin{table}[h]
\centering
\caption{Effects of Concentration on Price}
\begin{tabular}{ l c }
& \# of Data Sets \\
Significant positive effects & 76 \\
Non-significant positive effects & 30 \\
Non-significant negative effects & 11 \\
Significant negative effects & 4 \\
\textbf{TOTAL} & \textbf{121} \\
\end{tabular}
\end{table}

\textsuperscript{63} Leonard Weiss, 1989.
III.E.2 Electricity Market Structures

In electricity markets, there is little relevant evidence to date to provide guidance as to how particular generation markets will function if deregulated, since most markets are still completely regulated. A simple examination of concentration in power pools does suggest, however, that with ownership patterns of generation facilities as currently structured, the potential for abuse of market power is a serious possibility. Even without collusion, preliminary analyses suggest that an individual dominant firm with a market share of 20 to 30 percent will have opportunities to exercise horizontal market power. Detailed studies are needed, in which strategic pricing behavior is analyzed in the context of real market structures with various generation ownership patterns, transmission constraints, and opportunities for new entrants.

There are aspects of some electricity markets that may cause the relationship between concentration and price to be particularly strong. For example, in an electricity poolco many of the features to support the exercise of market power are especially present. Due to certain real-time physical characteristics of the electrical system (e.g., the inability to store electricity), "the poolco-based organization is more representative of an auctioning device than a true spot market, which creates added nuances related to gaming by competitors and the potential [for] incidences of collusion or exercise of market power."

In contrast to the more typical competitive market, a pure poolco would provide a market structure which, in essence, would collapse the contract-signing time and the delivery time into the same point in time. The contract terms would be the prices and quantities bid by suppliers into the poolco. Bids would be made in hourly increments, and until the total electricity demand for that hour were known (i.e., until deliveries of electricity had been made), the price for electricity in that hour would not be known. Furthermore, the market clearing price for electricity demand in any given hour would be based on the highest priced bid that was accepted in that hour in order to meet demand. All accepted bidders would be paid the same market clearing price. This is quite different, then, from many other

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64 In theory, the entry of new suppliers into a regional market -- either through the provision of existing generation from outside the region over transmission ties, or through the construction of new facilities within the region, is a crucial factor in limiting the ability of a dominant supplier to abuse horizontal market power. However, strategic pricing behavior by existing owners of generation may make entrance into such a market quite difficult.

65 NARUC’s Glossary describes a poolco as a "specialized, centrally dispatched spot market power pool that functions as a short-term market. In the discussion of poolco that follows, many of the concerns identified have to do with electricity markets (or spot markets) generally. This is not meant to be a systematic comparison of alternative electric industry structures (e.g., the "poolco" vs. bilateral contract debate), any of which will likely include some form of a spot market. Rather, we wish merely to point out some specific pitfalls that could arise from an unfortunate combination of: 1) physical requirements of the electric power system, 2) high levels of concentration of ownership of electric generation, and 3) particular market structures such as "poolco."

markets where wholesale customers typically pay different prices for the same product delivered at the same time.

Another key difference worth highlighting is the fact that in a pure poolco a buyer could not take time to hunt around for the best deals when he/she was interested in lining up electricity purchases for a given hour, nor could a buyer negotiate the lowest price by playing one seller off against another. The "contract price" would simply be defined by the highest priced amount of generation bid into the poolco that was required to meet total demand in each hour.

Electricity is somewhat of a unique commodity in that electricity buyers' ability to influence their own aggregate demand from hour to hour is very limited -- there is little load control or load management technology built into the supply/demand system for electricity. Therefore, in a poolco, if the prices in certain hours were typically higher than most buyers would be willing to pay, these buyers could not suddenly decide to buy less, or no, electricity for delivery in those hours. Yet, in markets for other types of goods, if the prices offered are higher than buyers want to pay, then they can often wait to buy the product for significant periods of time, or at least until they have a chance to try to negotiate with several suppliers to see if they can bring the selling price down.

Generation suppliers would want, and be able, to bid above their variable costs is due to a strong "leveraging" effect that exists in poolcos. A critical aspect of poolcos is that the owner of a marginal unit that was bid above variable cost and set the market clearing price would earn additional profits both on his marginal unit and on any of his units that he bid at a lower price, and therefore that would be dispatched prior to the marginal unit. In fact, if an owner had many units that he had bid at lower prices, he would have an even greater incentive to raise his bid for the prospective marginal unit quite high because the risk of that unit not being dispatched, and the risk of not recovering some of the fixed costs associated with that prospective marginal unit, would be lower than the pay-off in extra profits paid to all of his non-marginal units if the prospective marginal unit were dispatched at the higher bid and set the market clearing price. Hence, this effect would be especially likely for generation owners who own a wide range of different types of generating units (i.e., baseload, cycling, and peaking). If a generation owner owned units which were well distributed across the supply cost curve, then the owner could try to exercise this high-price bidding strategy at almost any demand level and impact the market clearing price in most hours during the year. Because baseload, cycling, and peaking units basically represent generation in different markets, leveraging allows for the exercise of market power in one market (e.g., peaking) to influence the price of power in another market (e.g., baseload) in a very deterministic way.

Thus, there is a huge potential "leveraging" effect on fixed cost recovery that would inform each generation owner's bidding strategy. Again, the "leveraging" derives from the fact that the more generating units an owner has had dispatched ahead of the unit competing to be the marginal unit in a given hour, the greater the potential payoff would be to that owner to bid that unit at a price significantly higher than its variable cost. This is true even if the marginal unit were dispatched less often than it would have been if it had been bid at close to variable cost, as long as the extra cash flow from the dispatched non-marginal units more than compensates for the lost cash flow from the reduced amount of dispatch of the marginal unit.
In a poolco, market power may be exercised due to the underlying fundamentals of the industry."

Wisconsin's EIS noted that: "If certain generation companies retain, and are able to exercise, significant market power when bidding into the pool [poolco], then the underlying goals of economically efficient prices will not be achieved ... consumers would be forced to overpay for electricity, while investors in generation companies would realize excessive profits." This situation is very likely to occur if there are only a few owners of most generating units in a region, and may happen even with many owners. Furthermore, achieving a situation where there are more than just a few owners of generation in a region may be quite difficult in the long run, unless strict constraints are put on market shares. The electricity industry may have "increasing returns to scale" with respect to the amount of generation owned by a single entity, such that larger owners of generation will tend to get larger, eventually concentrating ownership in a few companies. If the tremendous savings claimed for recent electric utility mergers are even partially credible, they suggest scale economies in ownership that are at the same time too appealing to be resisted, and too powerful to sustain a sufficient number of firms for a competitive market in generation, in each region of the country.

At a general level, the considerations summarized briefly above suggest that substantial additional research on horizontal market power in electricity markets is needed, and that the deregulation of generation assets should move forward very cautiously, if at all, prior to the availability of more information and insight into these issues. Specific policies to mitigate market power may be aimed at market concentration or barriers to entry. Where concentration of generation is an issue, it might be temporarily addressed through spinning off generating assets, as in the California Commission's December, 1995 decision. However, even this approach may not be adequate in the long run given future opportunities for reaggregation of generation assets through mergers and acquisitions.

Thus, limits restricting ownership of generation are likely to be necessary in a deregulated generation market. For example, as a condition for certification to sell power into a particular power pool, a generator might be required to have ownership interest in no more than 15 percent, or less, of the capacity active in that market. Policy measures to address barriers for entry might involve open access to transmission wires, power pool membership requirements, and auctioning plant sites (locations with fuel access, grid access and public acceptability are scarce). Holding stranded cost recovery hostage may be the most effective policy lever for enlisting utility cooperation in setting up competitive market structures to foster competition, but this will only be a possibility where stranded costs are significant. It is, therefore, imperative that the problems and solutions relevant to considerations of market power be identified and put in place early in the transition to a more competitive electric generation market.

III.E.3 Vertical Integration and Market Power

Our discussion of market power, above, was restricted to considerations of horizontal market power in generation. Vertical integration (meaning the ownership of generation, transmission, and
distribution) raises its own market power concerns, particularly when the integration includes regulated and deregulated activities. One of the unique characteristics of the electric industry is that transmission and distribution wires businesses are clearly natural monopolies, and thus will need to be regulated even if there is wholesale or retail competition in the generation market. Regulation at both the distribution level and the transmission level could be a potential source of distortions because they profoundly affect the way the unregulated parts of the system, and the system as a whole, operate.68

The two antitrust problems that can arise with vertical integration in electricity are evasion of regulation and foreclosure of competition.69 An integrated company may attempt to improperly allocate costs to the regulated business or inflate the prices paid by the regulated business to the unregulated one, thereby evading regulation. An integrated company may foreclose competition by giving preferential treatment to its affiliate. For example, a regulated distribution company may purchase from its affiliated unregulated generation company, even if the generator is not the lowest cost supplier. There are numerous examples of abuse of vertical integration in the telecommunications industry. If generation is owned by such an affiliate, then sophisticated affiliate transaction rules will be required as part of any restructuring proposal.

Ultimately, in order for restructuring to work (particularly retail competition), it may be necessary to have complete corporate separation of regulated and unregulated activities. Without full separation, a great deal of regulatory oversight is necessary (but perhaps not sufficient) to ensure competitive behavior. This might cause regulation to be just as comprehensive under restructuring as under the current regulatory system.

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III.E.4 Conclusions Regarding Competitive Markets for Generation

In conclusion, due to many factors, the potential for competition electric generation is, in many ways, quite different from the competitive ideal. Many constraints exist, both physical and economic, which tend to lead to market barriers to new market entrants. Where deregulation of the generation portion of the industry moves forward, then, significant market failures should be anticipated, and preventative measures should be taken to address them. Policies to promote competitive electricity markets could include restricting or discouraging concentration in generation markets, and requiring or encouraging vertical separation. Policies must also be directed at eliminating or reducing barriers to entry for new generating units, and markets should be structured in a way to minimize these barriers. In legislation for restructuring, it may be important for utility regulators to be given more authority and resources to deal with market power issues (horizontal and vertical). Information will be crucial in this regard. Someone will need to know about a utility's fuel costs and plant outages in order to determine whether market power has been abused. This can be a difficult determination, which could be rendered impossible if information is not readily available. State utility commissions must also prepare to vigorously regulate the allocation of costs and resources between regulated and unregulated affiliates.
IV. FINDINGS, IMPLICATIONS AND RESEARCH PRIORITIES FOR STATE LEGISLATORS AND REGULATORS

Below, we summarize the key findings and implications that have emerged from the analyses described in the previous sections:

IV.A Findings

● To lower electric rates to all customers in the short-to-medium term some strandable costs must be written off against stockholders. Almost all strandable or uneconomic generation assets will disappear over the next 5 to 10 years, even without restructuring the industry.

● A fully deregulated, competitive generation market is probably possible under certain conditions, but it may lead to increased average costs for consumers, as well as to increased risks for stockholders, relative to a partially regulated, partially competitive generation market. A continuation of cost-of-service regulation may, in fact, lead to the lowest generation rates in the long term, if market prices for generation increase over time due to inflation in capital costs.

● Public interest objectives of equity, environmental protection, resource diversity, and the development of cost-effective energy efficiency and renewable technologies could suffer as a result of completely substituting market reliance for regulation.

● Tight power pools yield a more socially optimal dispatch of generation plants than a poolco might since, in theory, tight power poolco dispatch is the mathematically least cost way. A poolco may also have a built-in tendency to exacerbate problems of market power.

● Current cost-of-service regulation is much more likely to yield stable rates, while market-based prices are likely to be much more volatile. Small customers probably prefer stable rates.

● Competitive forces may increase the types and gradations of services and rate options available, and thus could allow consumers to choose only the services they need at potentially lower costs. This is only likely to occur if customers have complete and accurate information, significant bargaining and negotiating power, and time to devote to making those choices. However, if energy services are bundled with non-energy services, consumers will not be able to tell if their electric rates went up or down.

● Restructuring the electric industry could have substantial transition and transaction costs, because the industry is so complex. These additional costs could be greater than the savings that increased competition could yield.
• If generation is not fully divested when deregulated, but is spun-off into utility subsidiaries instead, considerable regulatory attention will be required to establish effective subsidiary transaction rules.

IV.B Implications

• Regulators and legislators must first be clear about what the problems are with the current industry structure, and what has caused the problems in their state or region, before the problems can be fixed.

• Regulators and legislators should establish a clear set of objectives and principles to provide a framework for evaluating both the short- and long-term implications of specific restructuring proposals that are intended to correct specific problems with the current structure and/or regulation of the electric utility industry. In particular, regulators and legislators should decide whether the lowest possible electric rates or maximum economic efficiency is the highest priority.

• Because there is an important distinction to be made between lowering rates and increasing economic efficiency, these goals might conflict under restructuring scenarios where generation is completely deregulated, especially in the long run. Those advocates of restructuring that support economic efficiency as a goal ought to take externalities into account to be consistent, even though doing so will cause prices to be higher.

• Economies of scale and scope may exist for owners of generation, and, therefore, it may be difficult to prevent a tendency toward oligopoly in the generation sector if generation is fully deregulated. Since anti-trust activity may be too slow and ineffective to cope with this tendency, PUCs will have to build measures to mitigate market power into restructuring schemes if market power is going to be effectively curtailed.

• Legislators should give utility regulators the authority to deal with market power, and not force regulators to rely on anti-trust laws.

• In considering specific restructuring proposals, regulators and legislators should take into account the specific economic and institutional context of the electricity industry in their region.

• Increasing competition and reliance on markets in the electric industry should not be an objective in and of itself. It could, however, be a means of achieving primary objectives identified at the beginning of the restructuring process, which should include relevant social goals.

• Regulators and legislators must ensure that public interest objectives of equity, environmental quality, energy efficiency, resource diversity, energy security, and economic development do not suffer in substituting reliance on markets for regulation.

IV.C Further Research
In each case, there is some potential for useful research at a national scale or on an abstract basis -- but much more research should be performed on a system-specific basis and on a region-specific basis:

- **Specific high-priority research questions include:** 1) What are the possible and likely cost decreases in electricity supply or services that could be obtained due to competitive pressures of retail competition relative to wholesale competition?, 2) What are the possible and likely cost increases in electricity supply due to transaction costs, increased supplier risk (which impacts the cost of capital) and potential abuse of market power if generation is fully deregulated under either wholesale or retail competition?, 3) What are the possible and likely cost shifts among customer groups, and, in particular, cost shifts to small or low-income residential customers under retail competition, especially when stranded costs are high?, 4) What market choices do retail customers really want, and how can the industry be organized to provide these options?, 5) To what extent economies of scale and scope exist in the electric utility industry?, To what extent do vertically-integrated utilities have economies of scope that would be lost if generation were fully deregulated, and/or if transmission ownership were separated from distribution system ownership?

- More research is needed on what market barriers exist for generation, DSM, and other potentially competitive services.

- More research should be done on potential market power problems inherent in the poolco model, before it is implemented. More research is also needed on how to conceptualize, analyze, measure and mitigate market power.

- More research is needed to identify ways in which regulatory policy that affects the structure of the electric industry can serve to decrease potential problems, costs and risks associated with restructuring.

- More research is needed on the extent to which a tight power pool is socially optimal under either wholesale or retail competition, or both.

- Given the uncertain range of costs, benefits and risks likely as a consequence of industry restructuring, regulators and legislators should consider an incremental approach in which the competitiveness of wholesale markets is tested and developed before embarking on retail competition. It may be the case that establishing a truly competitive wholesale generation market may achieve the goals of most industry restructuring advocates, once stranded costs have been fully paid off.
Documents of high priority/highly recommended for review are marked with an "***". Three documents are marked as such.


The author discusses the issue of "customer of last resort," namely the customer to whom retail suppliers do not and will not market because the customer lacks market power, which is usually a function of the size of the customer's demand and disposable income. Mechanisms to recreate the protections of regulation for these customers in a deregulated market include a properly designed affordability program, a well-designed conservation program, and tax-funded cash assistance. The author concludes that, together, these mechanisms can minimize the costs of credit and collection activities for the system as a whole. (length: 20 pages)


The author advocates a non-bypassable, usage-based "system benefits charge" on electric distribution services to recover costs associated with energy efficiency, low-income services, research and development (R&D), and cost-effective renewable energy acquisitions "to the extent that their initial cost streams exceed short-term commodity costs." He asserts that the charge would require no change in current rates or rate structures, since utilities today typically recover bypassable "stranded benefits charges" from all distribution system users based on volume of consumption. He maintains that states and publicly-owned utilities have authority to adopt such a universal charge, that it is consistent with the concept of energy conservation as a least-cost resource, that charges would not be likely to exceed 5 percent of current bills, and that it is compatible with both wholesale and retail wheeling proposals. (length: 5 pages)


On its own initiative, the Department established this docket to examine whether retail wheeling should be permitted in Connecticut. It concluded that "if retail wheeling is to be authorized, it should only be introduced at a time of capacity need, and then after a careful structuring to minimize the adverse effects on inelastic ratepayers and the viability of host utilities. Introduction prior to the time of capacity need would create production inefficiencies, increase stranded cost, use more of our non-renewable resources than previously required to meet Connecticut's power needs, disrupt implementation of the Clean Air Act, be contrary to State Energy Policy, and adversely affect the Integrated Resource Planning process ... the introduction of open generation competition for retail
sales is not in the best interests of the stakeholders, State Energy Policy, and the economy of the State of Connecticut." (length: 74 pages)


The DPUC recommended that electricity generation in the state be deregulated and that full retail access to power be allowed after major restructuring of the industry is completed. However, transmission and distribution should remain regulated as exclusive franchises, and thus generation assets should be divested from T&D functions. The DPUC also said that utilities should be given a reasonable opportunity to recover non-mitigatable stranded investment costs, and that an independent system operator would be needed to carry out economic dispatch at the New England regional level and insure reliability. Finally, the DPUC said that increased competition should not compromise state environmental policies.


Using the airline industry as an example, Cudahy demonstrates how problems fostered by deregulation come to the fore in a slumping economy. An exclusive focus on market efficiency may be too simplistic in light of bankruptcies, oligopoly, lost jobs, and chaotic pricing. Even with the enhanced participation of foreign carriers in the U.S. air market, Cudahy anticipates a return to more regulation in the airline industry, and suggests that this trend may apply to other deregulated industries. (length: 15 pages).


This report originated from a WPUI Roundtable on Electric Power Industry Trends and Regulatory Policy Directions convened by the PSCW. The discussion piece provides an integrated array of competitive policy options and options for regulatory change in Wisconsin based primarily on discussions with representatives of numerous stakeholder groups. This report does not provide a comprehensive analysis of the risks and benefits of these options. (length: 123 pages)

The EGA, a national trade association representing independent power producers, advocates functional unbundling of the generation sector. The Group claims that this a critical element to updating the "traditional utility bargain" such that the bargain symmetrically balances rights, obligations, and risks among utilities, wholesale suppliers, and customers. The EGA believes that a shared vision of the future should 1) reflect the realities of market-based competition in the generation sector within the larger framework of regulation, 2) be open to a rich variety of service options at competitive cost, and 3) be based on an appropriate allocation of risks and incentives for all. EGA also notes that in the process of reform, certain constraints should be observed: societal costs should be minimized, financial burdens should be broadly shared, and the reliability of utility service should be safeguarded. (length: 36 pages).


ELCON's eight principles are as follows: 1) market forces can do a better job than any government or regulatory agency in determining prices for a commodity such as electricity. 2) laws and regulations that restrict the development of competitive electricity markets should be rescinded or amended... 3) the benefits from competition will never fully materialize unless and until there is competition in both wholesale and retail electricity markets... 4) the owners and operators of transmission and distribution facilities, and the providers of coordination and system control services, should be required to provide access to those facilities and services to any buyer or seller on a nondiscriminatory, common-carrier basis. 5) rates for the use of transmission and distribution facilities should reflect the actual cost of providing the services... 6) resource planning is not a natural monopoly... 7) legitimate and verifiable transition costs that develop as a result of competition should be recovered by an equitable split among ratepayers, shareholders, and taxpayers... 8) the potential for transition costs should not be used as an excuse to prevent or delay the onset of a competitive electricity market. (length: 16 pages).


The authors conclude that restructuring based on bilateral contracts between suppliers and customers will be more efficient because it will lead to greater consumer choice and lower costs. They assert that long-term benefits to consumers and producers due to restructuring ($80 to $100 billion/year) will vastly outstrip the associated transitional costs ($200 to $300 billion total). Though the three sources of benefits (improvements in efficiency of operations, improvements in efficiency of capital utilization, and improvements in the decision making associated with capital investment) seem logical, the derivation of their "back of the envelope" values do not. For example, in calculating consumer surplus, the authors assume that all power consumed at the end-use is acquired by utilities via wholesale power contracts (rather than produced by utilities themselves), and that the drop in the price of wholesale power of roughly $20 per MWH is due entirely to competitive forces/efficiency gains.
rather than to reductions in fuel costs, depreciated capital costs, etc. With regard to producer surplus, the authors attribute the shift from more expensive coal and nuclear units to less expensive gas fired units to competitive forces rather than to the fact that a heavily base-loaded electric industry (such as the one in the U.S. right now) does not require any more expensive base-load capacity but does require cheaper intermediate and peaking capacity. In other words, the shift is necessary to acquire a capacity mix which meets customer load. (length: 52 pages)


Daniel Wm. Fessler reiterates that 1) the primary goal of California's electric restructuring proceeding is to lower rates for all of California's electric customers by letting customers choose their own electric supplier in a competitive marketplace, and that 2) the Commission recognizes that market power is an issue that needs to be addressed. (length: 8 pages)


This paper reviews the experience of the natural gas, telecommunications, airlines, and railroads industries and identifies common patterns in terms of timing, industry structure, the market, technology, costs, diversification, financial expectations, and the continuum of change. The authors define five distinct, predictable, and inevitable stages in the progression of these industries: "equilibrium," "rumblings in the provinces," "identity crisis," "refocus," and "dynamic competition." They also track the behavior of traditional providers, competitors, customers, regulators, financial markets, and employees at each of these stages. The report concludes with implications for the electric industry. (length: 24 pages)


This report focuses on how state regulators can simultaneously attain two apparently incompatible goals, namely the goal of providing benefits to all parties through the introduction of market-based principles and the goal of achieving a cleaner environment through the use of renewables, energy efficiency, and other new technologies. The report provides design criteria which are consistent with public interest responsibilities and can help in identifying the parameters within which new industry policies and structures could be developed. The report also provides key decision points in restructuring/reregulation, a prototype model for the industry, and the role of state regulators. (length: 190 pages)

This paper outlines necessary steps to implementing an efficient competitive electricity market given unique technical constraints and natural monopoly elements in the existing electricity market. Hogan emphasizes that in transitioning from the current market to a competitive one, "old assumptions and convenient fictions" about energy and capacity, generation and transmission, cost-effective conservation, environmental protection, etc., will need to be revisited. He also discusses the structure of a competitive wholesale electricity market and of a fully unbundled competitive electricity market, as well as the role of each player under each structure. Hogan states that a competitive wholesale market with a readily available spot price and time-of-use pricing for the energy cost component based on the arm's length spot price are the only two essential elements of "efficient (operational) direct access." (length: 32 pages).


This memorandum discusses 1) how the issues of horizontal market power depend upon the relevant regional market and associated transmission constraints, 2) the estimate that there will be many markets that display a high concentration of ownership and control, requiring policies to mitigate market power or change the concentration of ownership, and 3) how the close connection between market pricing and any valuation of stranded assets means that state regulators will be necessarily immersed in this issue as the process of electricity industry restructuring moves to greater reliance on competition. (length: 13 pages).


The authors explain that in the US, the increased emphasis on competition is not just about seeking lower electricity prices; over the past 15 years, the real price of electricity for all customer classes has been declining, though these regulated industry prices are/appear to be above the prices that are available from the competitive market. They point to other factors such as reduced economies of scale in electricity generation, greater recognition of the importance of uncertainty, and a growing preference for service diversity and customer choice. The authors then provide a number of restructuring principles and objectives, two generic restructuring models, and a discussion of the roles of each model's players. (length: 76 pages).

The author emphasizes three primary features of the economics of transmission that should be central to a transmission services pricing policy. First, there is no separable transmission service that can be provided independent of economic dispatch. Second, transmission rights can not be built on the traditional wheeling model that assumes that specific power moves to specific customers. Third, there is no single number that meaningfully describes the capacity of a transmission grid, and there is no single price. On the subject of efficient pricing, the author explains that opportunity-cost pricing in the short run is a natural byproduct of an economic dispatch and guarantees the most efficient use of the electrical system. The incentives of short-run opportunity costs and the protection of long-run contracts provide the ingredients for investment in new generation. (length: 50 pages).


In discussing industry restructuring, competition, and economic efficiency, the authors point out that "even in the world of economic theory, there are situations in which increased competition reduces [economic] efficiency", and in the real world, this possibility is even more likely. The authors discuss short-run and long-run efficiency in terms of production, variety, and allocation, and conclude that "if restructuring is to achieve the desired end of increased efficiency, it must be focused on that end, not simply on increasing competition". They discuss necessary features of efficient competition in the electricity industry, and warn that the potential for the interaction between competitive forces and regulation to generate inefficiencies must not be overlooked. They also remind the reader that efficiency is not the only objective of public policy, and that while efficiency considerations come into play with respect to these other objectives (e.g., safety, reliability, environmental protection, equity), efficiency analysis does not capture everything included in them. Finally, the authors emphasize that if efficient competition at the wholesale and/or retail levels is to be achieved, then the stranded investment problem must be resolved. (length: 20 pages).


This Framework puts forth general principles, some of which are: a) all utility customers must see short- and long-term reductions in their rates and bills, as well as other benefits from restructuring; b) PBR mechanisms should not reward a utility for achievements which would otherwise be attained under the existing applicable regulatory mechanism; c) the maximum percentage of stranded costs which are eligible for recovery from customers by the utility through the CTC must be less than 100 percent; d) the Commission must not wait to deal with issues of market power at some point after restructuring has been implemented; e) power pooling must be voluntary and flexible if it is to serve the needs of both buyers and sellers; f) all sources of generation must meet the same environmental
standards; g) to the extent that direct access is introduced, it must be available to all customer classes simultaneously, without arbitrary restrictions on small customer participation; h) the Commission shall take steps to ensure that the State's low-income customer and direct assistance programs and policies are preserved; and i) funding levels for energy efficiency and renewables RD&D and for conservation programs must be sustained. (length: 19 pages)


The authors state that in order to evaluate reform proposals, one must understand the problems they are designed to solve. They discuss the four "dimensions of efficiency" (i.e., short-run and long-run production efficiency and pricing) and the factors which influence each dimension (i.e., economic dispatch, equipment maintenance, fuel procurement, labor utilization, investment decisions, technological change, appliance stocks, marginal costs, etc.). They then discuss the status of each factor as it relates to the electricity industry. (length: 12 pages).


Four deregulation scenarios are evaluated against the dimensions of efficiency. The four scenarios are 1) deregulation at the retail level, 2) vertically integrated, regulation utilities and unregulated wholesale power contracts, 3) separation of regulated distribution from unregulated G&T wholesale market 4) separation of regulated distribution from unregulated G&T wholesale market, where all transmission and coordination facilities are owned and operated by the transmission-pooling entity. The authors conclude that establishing efficient retail rate structures will yield pricing efficiency, whereas deregulation of bulk power sales in and of itself will not. They also point out that the majority of unregulated wholesale transactions will be governed by long-term contracts (to hedge risk), the use of which implies that power purchasers will pay average prices that may differ substantially from the current marginal costs. They warn that regulation at both the distribution level and the transmission level is an important potential source of distortions due to "regulatory reach", and that the amount of cooperative behavior necessary to yield production efficiencies (i.e., through the pool) can also lead to monopoly pricing. (length: 26 pages).


The authors consider short-run competition at the generation level in deregulated bulk power supply markets given the existing concentration of generation plants. They identify several important public policy problems. First, where effective concentration is high, collusive behavior is likely. Horizontal
disintegration of holding companies could solve some of the problems associated with such behavior. Second, transmission capacity constraints will limit the ability of distant plants to compete for any area's load in the short run. The authors also consider long-run competition at the generation level in deregulated power markets. They conclude that in the absence of forced horizontal disintegration, market forces would not generally tend to reduce existing firm-level concentration. Generating entities already in a regional market, and thus involved in long-term relationships with a power pool and/or local distribution entities, are likely to have important advantages over potential new entrants in bidding to construct and operate new generating facilities. Preclusion from entry will lead to oligopolistic or monopolistic situations. The authors close with two key points regarding behavioral and governmental influences: 1) the tension between cooperation and competition is not likely to be easily resolved by "clever contractual or regulatory tricks", and 2) as long as there is substantial regulation anywhere in an electric power system, it can extend itself to supposedly unregulated parts of the system. (length: 20 pages).


The Maryland PSC has rejected retail wheeling. The PSC cited the state's relatively low rates, lack of expensive nuclear power plants, and few high-priced PURPA contracts as reasons why Maryland's electric utility industry is not currently in need of "dramatic fixes". Staff said that under retail wheeling, stranded costs could reach $1.6 billion. Instead, the PSC called for "sensible and progressive" changes, such as bidding for all new capacity, to take advantage of wholesale competition, which the PSC believes could reduce rates. (length: 68 pages)

Massachusetts Department of Public Utilities. Investigation by the Department of Public Utilities on its own Motion into electric industry restructuring, DPU 95-30. August 16, 1995.

The Massachusetts DPU order requires utilities to functionally unbundle their services, orders them to create their own restructuring plans through negotiation with stakeholders, emphasizes customer choice and direct access as the best ways to create a competitive market, and allows recovery of net, non-mitigatable stranded costs. The utilities' proposed plans must move the industry into customer choice; unbundle charges for generation, transmission, distribution, and ancillary services; create a charge to recover stranded investment; propose incentive regulation for transmission and distribution; and conform to five transitional principles. The order has been criticized for failing to protect renewables and take a stronger stand on environmental protection. (length: 49 pages)

The author argues that the owner of a plant whose only revenue is from a Poolco faces a game-theoretic problem. This problem is that to have any chance of recovering capacity investment, the plant must be bid for pool dispatch at a price that exceeds marginal cost, but not by so much that it falls out of dispatch order. Thus, if most plants with lower dispatch priority must live off the pool price, that price will usually exceed the short-run marginal cost of the most costly unit that runs. One of the author's key points is that if plants bid strategically at more than marginal cost, additional inefficiencies will result because some low marginal cost plants might overbid the eventual pool price and not be dispatched, while some high cost ones underbid the price and operate. (length: 13 pages).


Moody's estimates the possible range of total stranded costs for U.S. investor owned utility companies at $50 billion to $300 billion, depending on market price assumptions and assuming widespread competition by the year 2000. Under their "most likely scenario", stranded costs will total $135 billion. (Tellus cautions the reader that Moody's methodology is flawed in several respects.) The greatest dollar concentration of stranded cost exposure is among companies in the Northeast and Western U.S. To the extent that utilities absorb a significant portion of stranded costs, this will exert pressure on their credit ratings. (length: 18 pages).


This article explains that cost-effective electricity conservation, the development of renewable resources, programs for low-income electric customers and supportive research and development have been an integral part of the services delivered by most electric utilities. RAP warns that without some mechanism to preserve these desirable features of the current electric utility system, they are becoming inadvertent casualties of the uncertainty of the future of the industry. The article explains why a system benefits charge may be the best way to fund these services both now and in any competitive future that may arise.


This paper examines how utilities are attempting to improve the cost competitiveness of today's operating nuclear power plants. It also identifies some of the potential consequences of competition for nuclear power and for the regulatory role of the U.S. Nuclear Regulatory Commission (NRC). Finally, it addresses how the changing power markets could affect the prospects for the next generation of nuclear power plants. (length: 15 pages).
This report provides an overview of the environmental impacts of the electric industry and of primary environmental threats created by restructuring. It also provides an overview of the potential policy options and mechanisms for addressing the environmental risks created by restructuring. The options that are reviewed could be considered by regulators and policymakers for many different restructuring proposals and in many regional contexts. Finally, the report discusses some jurisdictional issues raised by the various environmental policies and mechanisms.


This paper provides an overview of how economic dispatch is achieved, in theory, and describes system dispatch and control methods currently used in competitive electricity markets overseas and in power pools in the U.S. The author explains that the spot market price must include a component to account for all factors that affect economic dispatch over a finite schedule period. This is due to the fact that the merit order of generating units is not only determined by the instantaneous marginal cost but is affected by the fixed costs and inflexibility constraints of the generating units. The author also provides numerical examples of how the spot price would be determined for centrally committed generating units. He concludes that "the greater the degree of control allocated by generators to the central dispatcher, the greater the opportunities for coordination of generating capacity across the system so as to increase efficiency and hence savings for both generators and consumers" (p.28).

(length: 51 pages)


This report offers perspectives on the future of the electric utility industry. The perspectives are developed first by examining economic, political and regulatory, societal, technological, and environmental trends that are 1) national and global in scope and 2) directly related to the industry. The trends are used to construct scenarios designed to be thought-provoking descriptions of potential futures. (length: 105 pages).

Volume I thoroughly reviews Wisconsin's existing regulation and industry structure, generic structure alternatives, and the potential economic, system, environmental, and socioeconomic effects of the "plausible extreme alternatives." This document provides a very thorough and carefully thought out review of the multitude of restructuring issues, and includes objective estimations of the short- and long-term costs and benefits of restructuring. Volume II includes all of the written comments received by the staff on the Draft EIS, as well as staff's responses to those comments. (Vol. I length: ~450 pages, Vol. II length: ~200 pages)


Based on the U.K. experience, the author shows that retail competition will not necessarily lead to a reduction of electricity prices or an industry that is more efficient in the long run. He states that prices to customers have increased more than would be expected without privatization, small captive customers have effectively subsidized larger customers, and utility profits have soared. The U.K.'s experience demonstrates that the financial benefits of retail competition may instead remain with utility shareholders, and that long-term planning and important public policy objectives may be sacrificed for short-term decisions driven by narrowly defined profit motives. (length: 8 pages)