EMF Report 15
Volume 1
April 1998

A COMPETITIVE ELECTRICITY INDUSTRY

Energy Modeling Forum
Stanford University
Stanford, California 94305-4023

Preface

The Energy Modeling Forum (EMF) was established in 1976 at Stanford University to provide a structural framework within which energy experts, analysts, and policymakers could meet to improve their understanding of critical energy and environmental problems. The fifteenth EMF study, "A Competitive Electricity Industry," was conducted by a working group comprised of leading international energy analysts and decisionmakers from government, private companies, universities, and research and consulting organizations. The EMF 15 working group met four times between September 1995 to September 1997 to discuss key issues and analyze a competitive electricity industry.

This report summarizes the discussions of the working group study. Inquiries about the study should be directed to the Energy Modeling Forum, 406 Terman Engineering Center, Stanford University, Stanford, California 94305, USA (telephone: (650) 723-0645; Fax: (650) 723-4107). Our web site address is: http://www-leland.stanford.edu/group/EMF.

Funding for this study was generously provided by the U.S. Department of Energy, the U.S. Environmental Protection Agency, and member organizations of the EMF Affiliates Program. Within the Department of Energy, the EMF received support from the following offices: the Energy Information Administration, the Office of Policy and International Affairs, the Office of Planning and Environment and the Office of Petroleum Reserves within the Office of the Assistant Secretary for Fossil Energy, and the Office of the Assistant Secretary for Conservation and Renewable Energy. Affiliate organizations include: BP America, Central Research of Institute of Electric Power Industry (Japan), Electricity Corporation of New Zealand, Electric Power Research Institute, Environment Canada, Exxon, Ford Motor, Mitsubishi Corporation, Natural Resources Canada, New Energy and Industrial Technology Development Organization (Japan), Pacific Gas and Electric, Shell International, and the United Kingdom Department of Trade and Industry. Additional support for this study from AMOCO is also gratefully acknowledged.

EMF's Senior Advisory Panel continues to offer valuable advice on topics as well as comments and suggestions for improving EMF reports. We would also like to acknowledge Michael Hsu, Edith Leni, and Susan Sweeney for their assistance in providing background information and in producing this report.

This volume reports the findings of the EMF working group. It does not necessarily represent the views of Stanford University, members of the Senior Advisory Panel, or any organizations providing financial support.

Table of Contents

Working Group Members

Jasmin Ansar	Pacific Gas & Electric Company
Hiroshi Asano	Central Research Inst for Electric Power Industry (Japan)
Martin L. Baughman	University of Texas at Austin
Normand Beaudoin	Environment Canada
Jan Braten	ECON, Centre for Economic Analysis (Norway)
Derek Bunn	London Business School
James Bushnell	University of California, Berkeley
Hung-po Chao	Electric Power Research Institute
John J. Conti	U.S. Department of Energy
Rajat Deb	LCG Consulting (California)
Michael Einhorn	U.S. Department of Justice
A. Denny Ellerman	Massachusetts Institute of Technology
Robert Entriken	Stanford University
Nigel L. Evans	Caminus Energy Limited (UK)
Robert Eynon	U.S. Department of Energy
Don Garber	San Diego Gas & Electric Company
Kenneth Gordon	National Economic Research Associates
Tom Grahame	U.S. Department of Energy
Frank C. Graves	Brattle/IRI (Massachusetts)
Richard Green	University of Cambridge
George Gross	University of Illinois
Arve Halseth	ECON, Centre for Economic Analysis (Norway)
Ned Helme	Center for Clean Air Policy
Bruce Humphrey	Cambridge Energy Research Associates
Hillard Huntington	Stanford University
Marija Ilic	Massachusetts Institute of Technology
Henry Lee	Harvard University
William Meroney	Federal Energy Regulatory Commission
Roger F. Naill	The AES Corporation
Sam Napolitano	U.S. Environmental Protection Agency
Dale Nesbitt	Altos Management Partners (California)
Shmuel S. Oren	University of California, Berkeley
Karen Palmer	Resources for the Future
Stephen Peck	Electric Power Research Institute
Ricardo Raineri	Universidad Catolica de Chile
E. Grant Read	University of Canterbury (New Zealand)
Scott Rogers	University of Toronto
Kjell Roland	ECON, Centre for Economic Analysis (Norway)
Geoffrey Rothwell	Stanford University
Hugh Rudnick	Universidad Catolica de Chile
Ram K. Sahi	Natural Resources Canada
Yves Smeers	Universite Catholique de Louvain (Belgium)
Charles Stalon	Private Consultant
James L. Sweeney	Stanford University
James Turnure	Environmental Protection Agency
John P. Weyant	Stanford University
Ray Williams	Pacific Gas & Electric Company
Nick Winter	Electricity Corporation of New Zealand
Frank Wolak	Stanford University
Frances Wood	OnLocation (Virginia)

Executive Summary

Prices, Markets and Government

Governments worldwide are restructuring their electric power industry to promote competition, facilitate investment, and improve economic efficiency. Although these policies may lead to substantial improvements in the operation of the electric power system, reforming this sector may also present some key challenges as well.

Electricity modelers have been developing analysis and estimates to help understand and anticipate problems that may arise in a more decentralized electricity market. Together with key potential model users, they have discussed some of their preliminary findings at working group meetings organized by Stanford University's Energy Modeling Forum over the last 18 months. This report presents some of the more important conclusions concerning several key problems in electricity restructuring.

Restructuring involves deregulating the generation sector—where the decisions about how much power to produce and what type of fuel to burn are made. Similarly, there are plans in many countries to include retail sales—where customers' use is measured and billed. However, these policies are not opening up the operation of the transmission and distribution wires to competitors because it is not economic to have more than one firm own and operate these functions within a region.

Market Power and Strategic Behavior

Definition and Detection

Restructuring has the potential to create significant economic gains if it produces more than a few large producers in any particular market.

Market power exists when a firm has both the incentive and ability to sustain market prices above competitive levels by changing its own output. Ownership of the marginal unit that sets the price, by itself, does not indicate market power. A firm needs to own sufficient other production to benefit from the price increase before it can have market power. Cooperation among large firms may also create opportunities for market power.

Market power can have an important time dimension. It may be prevalent in the short run and within certain localities. Over time and with expanded interregional linkages, market power should diminish. In the long run, market power is more likely to be a function of how well incumbents can prevent competition from new entrants through its pricing or merger strategy.

The detection and enforcement of market power, particularly when electricity prices are volatile, can be quite vexing.

- A rapid increase in prices could reflect market power, but it could also reflect a temporary physical shortage of capacity that needs to be corrected.

- Some competitors can impose market power by expanding rather than contracting output along a transmission system with congestion problems.

Influences on Market Power

The size of the largest firms may not truly reflect market power opportunities. Behavioral characteristics and institutions are important and often need to be modeled in a consistent framework to understand their likely impact. These conditions include:

- The availability of contracts that fix prices on some existing units;
- Companies owning both generation and retail supply when price increases can be passed through to customers;
- Consumers' ability to substitute away from electric power;
- The behavior of other large producers already in the market;
- The existence of a 'competitive fringe' or of must-run plants;
- The availability of new entrants as a form of competition.

Modeling Market Power

Economic models of market behavior attempt to incorporate these different behavioral as well as structural factors. When their assumptions and results are monitored carefully, they can provide insights on

- How much higher prices would be if market power is exercised?
- What is the relative magnitude of lost economic efficiency?
- How effective are policies for divesting assets, extending the coverage of fixed-price contracts, or expanding transmission links in mitigating potential market power problems?
- How should geographical boundaries be defined in studies seeking to measure market power in terms of firm size?

The report shows how modeling reveals the potential for market power to sustain prices above competitive levels in three key regions: England and Wales, the Nordic countries, and California.

Transmission Pricing Policy

Electric transmission is a network where the costs at one location depend upon what is happening elsewhere. This feature requires the system to have well-developed rules for locating where generation and loads are placed as well as for accounting for transmission losses and congestion.

Comparisons of models for existing transmission systems are difficult because the economic and technological characteristics of regional systems can differ significantly from each other. For this reason, the group focused attention on comparing different regional approaches for setting transmission pricing rather than on existing transmission models. The group focused on six principles for guiding the design of transmission policy in different countries and states:

- Promoting the efficient day-to-day operation of the bulk power market;
- Signaling locational advantages for investment in generation and demand;
- Signaling the need for investment in the transmission system;
- Compensating the owners of existing transmission assets;
- Simplicity and transparency;

- Political implementation or feasibility.

The first principle is concerned with short-run economic efficiency, the second through fourth with long-term efficiency, and the last two with implementation.

Promoting Daily System Operation

Countries have adopted different approaches for incorporating transmission losses and congestion in the day-to-day operation of the bulk power market. These approaches include:

- Essentially ignoring these costs and viewing all generation as being at a single point (England and Wales);
- Essentially pretending that all generation is at one point but impose transmission charges that approximate the costs of transmission losses (Norway and Sweden);
- Choosing generation based upon an explicit system model that includes these losses and constraints (New Zealand).

The first two approaches have the advantage of being relatively simple in design but they may result in inferior outcomes if conditions change quickly. The third approach avoids these problems as losses and congestion are resolved directly by the pricing system but assumes that the system is well known. However, it requires a pricing system that creates clear winners and losers from the restructuring process.

Signaling Investment in Generation and Loads

In the longer run, it may be possible to reduce transmission costs by influencing the location of plants and loads on the system. Most electrical systems do not allow their electricity prices to vary with the cost of congestion and losses. Nevertheless, they frequently have some pricing mechanisms that encourage production to locate closer to anticipated growth in electricity demand.

Expanding Transmission

Prices by location can also signal the need for investment to expand the transmission system, although most countries do not use such prices to guide investment. A significant price differential between nearby locations indicates that it is costly to transport electricity between these two points, perhaps due to congestion along the line linking them. A new line will reduce these costs and improve the efficient allocation of electricity. However, investment that relieves congestion will change prices and erode the price differentials. The investor will be unable to receive the funds once the investment is made. Long-term investment will also require new institutions that establish clear ownership or decision rights over expanding the system or that identify the right user coalition that will benefit from an expansion.

Compensating the Owners of Existing Transmission Assets

Owners of existing transmission assets need to be compensated. Transmission charges are usually set to recover historic costs. Use of ‘signaling’ prices would recover only a fraction of the allowed revenues. If a system uses ‘signaling’ prices, it must impose a large additional charge on each location’s price to raise sufficient revenues. In some cases, this additional charge can be sufficiently large as to hide the incentives provided by ‘nodal’ prices.

Simplicity and Transparency

Transmission prices should be understandable if they are to provide useful signals. This need may or may not require that pricing be simple. Users may not understand complex approaches for calculating price differentials but may need to know only the few prices that affect them. At the same time, users may not have much faith in simple approaches that do not represent actual costs accurately.

Political Implementation

Some proposed pricing systems can not be implemented because too many influential interests are likely to lose. For example, existing transmission pricing often suppresses regional differences in costs, a practice that may have to continue to avoid creating winners and losers.

Energy Sector and Environmental Impacts

The restructuring of the electric power industry should significantly change the industry's regulation and the way generators dispatch, operate, add and remove capacity, price and market electric power. These changes could fundamentally change electricity prices and demand and alter the eventual fuel mix of electric generation, which could either increase or reduce environmental emissions. The analysis discussed by the group focused primarily upon the United States.

Existing Estimates of Pollution

Several earlier studies for the United States estimated the resulting changes in nitrogen oxides (NO_x), carbon dioxide (CO_2), and other potential pollutants that might result from having more competitive electric power markets. Many studies indicated an increase in pollution levels, principally from increased coal use, that frequently resulted in emission levels that were several percentage points higher than their baseline values by the year 2000. However, there are other factors that could help restructuring reduce pollution emissions.

No studies estimate increases in sulfur dioxide (SO_2) because these emissions fall under a national cap regardless of shifts in fuel use by electric power companies. However, increased coal use could increase the demand for, and hence the costs of meeting, these SO_2 emissions targets.

Estimated increases in national CO_2 emissions range from minimal to almost 50% of the reductions needed by the year 2000 under the Climate Change Action Plan. The higher estimates assume greater growth in transmission capacity, more replacement of nuclear plants, and higher pollution emission rates than the lower ones.

A similar range exists for the effect on national NO_x emissions levels by the year 2000. However, even the higher estimates are relatively minor compared to the approximate 2 million ton reduction in national NO_x emissions that are anticipated from the Clean Air Act Amendments.

Restructuring and Environmental Protection

In the past, policymakers have feared several possible sources for increased pollution from restructuring:

- Competitive pressures may favor an increased use of existing coal plants, especially older more polluting ones.

- Nuclear plants may be retired more quickly with greater competition.
- Total electricity demand could increase, particularly if electricity costs and prices should fall with restructuring.
- Some higher-cost but less-polluting generation sources (e.g., renewables and energy efficiency programs) may become more difficult to introduce into the electric system when competitive suppliers must cover their capital costs in their bidding.

While each of these factors may contribute to greater pollution, there are other factors that may help to offset and even reverse these effects. Such factors include:

- Competition may encourage new entry of producers using gas-fired generation, which is significantly less polluting in sulfur dioxide and carbon dioxide than existing coal plants.
- There are very real limits on how rapidly the electricity transmission system connecting regions can expand and hence on how much existing coal can replace existing cleaner generation.
- Some increased electricity consumption may simply replace fuel use in other sectors and thus could even reduce pollution in certain circumstances.
- Improvements in the energy efficiency (heat rates) of plants will reduce the pollution per unit of delivered power.
- Some renewables, especially distributed resources, may be more profitable to sell if a more open transmission system removes subsidies to areas that are expensive to reach.

Some of the impacts favoring greater pollution appear more pronounced in the earlier years while other impacts contributing to pollution reductions are more important in later years. This uncertainty associated with a diverse set of factors makes it quite difficult to develop precise estimates for the environmental impacts of restructuring. Moreover, a major difficulty in comparing existing estimates of the net emissions impacts is that the definition of what would happen in the absence of restructuring can often vary from one source to another.

Markets and Environmental Policy

In general, restructuring is likely to improve the performance of incentive-based environmental policies, such as emissions allowance trading, through better incentives for cost minimization. Conversely, the costs and environmental consequences of less efficient environmental policies are magnified.

To the extent that negative environmental impacts occur as restructuring of the electric power industry takes place, these impacts are not the result of restructuring per se. Instead, the problem arises from the failure to require electricity generators to account for the external costs associated with pollution, whether it comes from current plant operations or changes in operations under competition. Governments can design policies that would protect the environment without hindering the increased competition created by the restructuring process. The environmental impacts of a market dominated by a few large producers may require additional policies. The pollution effects when imperfect competition is more pervasive have not been studied as much and deserve additional analysis.

A COMPETITIVE ELECTRICITY INDUSTRY*

Prices, Markets and Government

If frost ruins the Florida orange crop or geopolitics in the Middle East disrupts oil markets, people expect to pay more to relieve the shortage. But if similar conditions affect the supply and demand for electricity, Americans do not expect to suddenly pay more during the shortage, and policymakers may not allow it. These circumstances could prevail even if deregulation is causing the industry's costs and prices to decline over the long run. How producers, consumers and politicians adjust to the new realities of competitive electricity markets will strongly influence how successful efforts to restructure that industry will be. Although many consumers and producers may be protected from price volatility through longer-term contracts, fluctuating system prices may generate significant concern and may also influence the premium that people pay for insuring against sharp price movements.

Policies promoting decentralized generation decisions are likely to induce widely fluctuating prices in systems that are not dependent on hydroelectric power. Electricity's value changes dramatically with the time of day it is being used. Moreover, it cannot be easily stored for future use. Under such conditions, how will one know whether fluctuating prices reflect real physical scarcities or attempts to manipulate prices? Regulators may intervene at the wrong time to prevent volatile prices that are actually helping the electric system to operate more efficiently. This situation represents one kind of problem that may arise in electricity markets as restructuring proceeds.

Electricity modelers have been developing analysis and estimates to help understand and anticipate problems that may arise in a more decentralized electricity market. Together with key potential model users, they have discussed some of their preliminary findings at working group meetings organized by Stanford University's Energy Modeling Forum over the last 18 months. This report presents some of the more important conclusions concerning three potential problems in electricity restructuring. First, some generating firms may exercise market power and hold prices artificially higher than the least-cost dispatch level for a sustained period. Second, governments may adopt rules that distort incentives, especially in governing access to transmission. And third, there may be more polluting emissions under certain conditions as a result of the type of electric generation that may be more cost effective to operate in more competitive markets. The report discusses each of these issues, after a few brief comments about the pending changes in electricity regulation.

A New Regulatory Regime

Governments worldwide are restructuring their electric power industry to promote competition, facilitate investment, and improve economic efficiency. An

* Readers should look in the endnotes section for key references.

important motivation has been that public ownership or traditional cost-of-service regulation of privately owned utilities has failed to provide adequate incentives for containing costs as efficiently as in more competitive industries. Within the United States, differences in regulatory environments have led to a marked price disparity among states. The wholesale electricity prices in neighboring franchise areas have been only one-half or less than the prices in California, New York and New England. Industries dependent on electricity and located in these high-price states argue that they are operating at a significant cost disadvantage. Outside the United States, restructuring has been combined with privatization of publicly owned utilities, partly to find new sources of investment funding.

Restructuring involves making the decisions about generating and selling power more decentralized. It also involves unbundling the separate functions in the industry:

- producing the power from fossil fuels or some other energy source (generation),
- moving power along high-voltage wires (transmission),
- moving power along lower-voltage wires (distribution), and
- selling to and billing customers (retail sales).

As a result, the combined forces of supply and demand conditions rather than the historic costs of the underlying assets will determine electricity prices. This change requires new approaches for thinking about how electricity prices will be set in the future.

Restructuring involves deregulating the generation sector—where the decisions about how much power to produce and what type of fuel to burn are made. Similarly, there are plans in many countries to deregulate retail sales—where customers' use is measured and billed. However, the operation of the transmission and distribution wires are likely to remain regulated because it is not economic to have more than one firm own and operate these functions within a region.

This fact complicates the task of restructuring this industry because decisions about generating and transmitting power are closely intertwined. The daily operation of the transmission system depends critically upon where and when to generate power. Longer-run decisions about investing in generation or loads are closely linked to those concerned with expanding the transmission system. The existence of these interrelationships, or complementarities, between functions presents opportunities to operate and expand both systems more efficiently or at a lower cost when done jointly rather than separately. A fundamental issue in restructuring concerns how to decentralize decisions about generation and loads and still acknowledge the complementarities between generation and transmission.

An important development in restructured power markets is how to provide for the system reliability and other ancillary services provided previously by the integrated utility. Power systems are complex and require that someone provide a set of ancillary services when and where they are needed. It is possible to establish a second set of markets and prices for handling reactive power and other services needed for a reliable electrical system. In a market-oriented system, opportunities exist to shift reliability from a supply-side and engineering phenomenon to one based more on incorporating economic demand-side considerations through the pricing system.

Market Power and Strategic Behavior

In perfectly competitive markets, the cost of the most expensive unit that is still being sold at a particular hour and location—its marginal cost—sets the market price. Consumers who remain in the market value their electricity at this price or above. Similarly, producers remaining in the market have costs equal to or below this price. However, prices also compensate owners and workers. Compensation, then, may work against an efficient allocation of resources because it provides incentives for some participants to distort prices in their favor if they can. Whether they are sufficiently large to distort prices remains the critical problem of market power.

Restructuring has the potential to create significant economic gains. As long as incentives for expanding interregional electricity trade are not thwarted, high-cost regions will import lower-cost power, while low-cost regions will earn more by selling to high-cost markets. Investment risks will shift to those who are willing to bear them in return for higher possible returns. In addition, consumers may value electricity differentiated by time of use and reliability more than the homogenous product available under traditional regulation. And finally, electricity generators will have stronger incentives to lower costs and increase availability than under cost-of-service regulation.

Defining Market Control

Large generating firms controlling prices could erase much of these potential gains. Market power exists when a firm has both the incentive and ability to sustain market prices above competitive levels by changing its own output. Markets are never perfect but instead have imperfections such as lumpy capacity increments, a finite number of players, regulatory threat, and imperfect capital markets among other factors. These imperfections will raise prices above "perfect" purely competitive levels. The key question is whether they more accurately reflect the marginal costs of providing electric power than does cost-of-service regulation.

Ownership of the marginal unit that sets the price, by itself, does not indicate market power. A generating firm needs to own sufficient other production to benefit from the price increase before it can have market power.

Market power has an important time dimension. It may be prevalent in the short run before new investments can be made to expand the system. Over time and with expanded interregional linkages, market power should diminish. In the long run, market power is more likely to be a function of how well incumbents can prevent competition from new entrants through their pricing or merger strategies.

Market power can arise when one or a few firms own a significant share of a region's productive capacity in the absence of competition from interregional power flows, competing energy sources, or new entrants. This potential increases when such a firm owns a critical ("must-run") plant that has important strategic or locational significance. Transmission constraints can create serious market power problems. Competitive generator access to transmission or competitive transmission investment is critical for reducing such market power.

The previous discussion focuses on the prospects for exercising market power in electricity generation. However, similar concerns may arise in the metering and retail marketing business, too. (Distribution wires will remain regulated.) Legislation in some states like Massachusetts appears to be providing existing utilities with a head start and protecting them from new competition in the retail supply business over the next several years. Most existing utilities are selling their generation and focusing on the retail. They have managed to move their stranded cost subsidy reimbursements across time and across customer classes in a way that diminishes the opportunity for new entrants to compete for the retail and marketing business.

Measuring Market Control

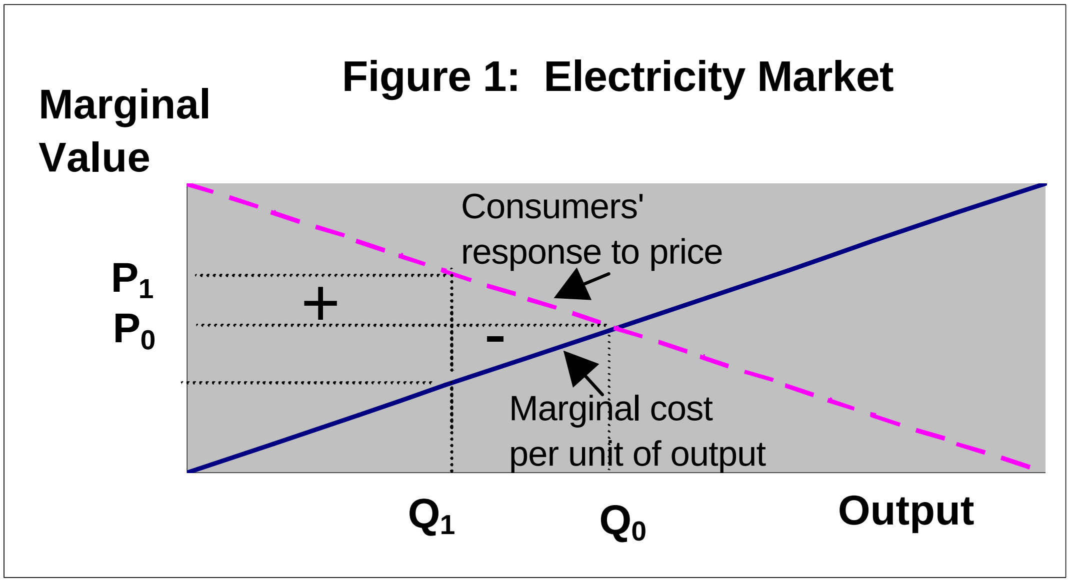
The detection and enforcement of market power, particularly when electricity prices are volatile, can be quite vexing. A significant price rise could indicate physical scarcities induced by constraints operating at certain times or locations that are not the result of direct price manipulation. The price increase under these conditions provides the incentives for competitors to find ways to overcome the bottleneck, making the system operate more efficiently. It is difficult to discern these conditions from behavior that manipulates prices.

Another problem in detecting market power is that firms, under certain conditions, can raise prices and their profits by expanding rather than holding back on output. Congested transmission lines can create a situation where a firm may have incentives to increase output to prevent other generators from providing power along certain links. This situation will prevail when there are significant interactions between links, known as "loop flows," that arise because electricity cannot be channeled along a direct line between two points but flows along all possible paths in the system.

Most firms considering price manipulation offer output at prices above their marginal costs. In pursuing this objective, a firm must balance the income gain from higher prices on the units it continues to operate with the income loss from units that it removes from the market. The firm's net financial position will depend upon several key impacts:

- How much higher can prices be sustained?
- Over how many units?
- What would be the price level without manipulation?
- How expensive would it be to operate the units removed from the market?

Figure 1 shows the factors that influence the firm's net position when there exists a single firm in the industry. The upward-sloping curve extending from the bottom left to the upper right shows the cost of the last unit added (on the vertical axis) at each total level of output (on the horizontal axis). When the firm reduces its output from Q_0 to Q_1, consumers will bid against each other for the fewer units and push prices upward along the industry demand curve (labeled as dashes) from P_0 to P_1. The firm gains P_1-P_0 on each of the Q_1 units it continues to produce. The rectangle filled with this large plus sign indicates this increased revenue. Meanwhile, the firm loses an amount (P_0 – the cost of the unit) on each unit it removes from



the market. The triangle filled with the large negative sign indicates these lost revenues. The relative size of these changes in income determines the incentives for the firm to withhold output.

Influences on Market Control

A number of factors will affect the firm's potential to profit from withholding production. First, in many electricity markets, retail suppliers (companies that sell power to the final customer) sign contracts with generators or financial institutions that hold prices fixed over a certain period. Generators that enter into such contracts will have fewer units whose price can rise when they try to remove some production. Thus, they have fewer incentives to curtail output to sustain higher prices.

Second, when allowed, ownership may also affect market power, as when a company owns both generation and retail supply. In these situations, the retail supplier may have incentives to accept higher prices from generation units that it owns, if it can pass through that price increase to its customers. This situation assumes little competition in supply. Most state proposals within the United States forbid the same company from holding both generation and retail businesses that transact with each other.

Third, consumers' ability to substitute away from electric power can limit price increases, thereby dramatically reducing market power. Real-time pricing of electricity will allow consumers to respond to shifts in the cost of electricity over the course of day or year. Policies that promote the responsiveness of consumers to price changes will help to mitigate the ability of firms to raise prices. The exercise of market power will cause greater price increases when the price elasticity of demand for electricity is smaller, although curtailed output per unit of price increase will be less.

And fourth, the behavior of other producers in the market often affects the market price after the firm removes production. In the opposite extreme of the situation depicted in Figure 1, there could be multiple firms, each one fiercely competing against the others. Under these conditions, the price remains at P_0 when the firm reduces output from Q_0 to Q_1, because other firms expand output to meet the demand at that price. The firm that initiates the action sees no increased revenue on the amount Q_1 it continues to supply. In fact, it loses income because it is simply relinquishing sales to other firms rather than affecting the market price.

Many electricity markets may be characterized by a more intermediate situation, where several large firms, each with some ability to influence the market price, operate. Under these conditions, the strategic behavior by the other large firms significantly influences how much a firm constrains output. There exists a wide range of possible results depending upon the strategies that the firm expects the other firms to adopt. In general, a firm opts for a higher-price, lower-volume path--one further from the competitive outcome--when it expects that the other large firms will not react to their withholding and change their output.

Most electricity markets with several large firms also include smaller producers, sometimes referred to as the "competitive fringe." These smaller producers have no incentive to curtail output because they individually own too few plants to benefit from influencing prices. When the market price rises due to actions by the larger firms, these producers will supply additional electricity that is cost effective at the new higher price. For this reason, availability of supply from these "fringe" producers will decrease the market power of a large firm. Abundant hydroelectric generation during "wet" years reduces the ability of larger firms to increase prices in regions like California. Alternatively, hydroelectricity capacity may be constrained during high-peak periods, resulting in opportunities for larger firms to exercise more market power.

Modeling Market Control

Traditional measures of market power are based upon the market shares of the firms and how the product and region are defined. However, as the preceding discussion emphasizes, the presence of large firms is only one dimension of market power. Behavior of all participants on both the demand and supply sides is not incorporated in these traditional measures. Moreover, new entry can provide competition in markets that are dominated currently by relatively large firms. The degree of entry will depend not only upon the cost structure of existing and new firms but also upon ready access to the transmission system, which must be continually expanded and upgraded.

Economic models of market behavior attempt to incorporate these different behavioral as well as structural factors. They can provide insights on

- How much higher prices would be if market power is exercised?
- What is the relative magnitude of lost economic efficiency?
- How effective are policies for divesting assets, extending the coverage of fixed-price contracts, or expanding transmission links in miti-

gating potential market power problems?

- How should geographical boundaries be defined in studies seeking to measure market power in terms of firm size?

At the same time, results from these economic models need to be interpreted carefully. They indicate the potential for price manipulation, but firms may be motivated by other factors to refrain from restricting output. In addition, results from these models may change significantly with different assumptions about consumers' response to price, how other firms react, and the cost structure of the asset base owned by a firm with market power. Different estimates of market power could reflect differences in methodologies rather than differences in market structure and behavior, thus complicating comparisons across studies and making interregional comparisons difficult.

Analysts have applied models to measure the extent of market power and the effects of different policies in a range of countries and regions. We consider studies on three different countries: England and Wales, the Nordic countries, and California.

English and Welsh Electricity

Two large producing companies, National Power and PowerGen, have tended to set market prices most of the time in the English and Welsh electricity markets. Such control over the market has given these firms the ability to charge prices well above their marginal costs and to earn substantial income. Estimates by Green (please see the endnotes) for the early 1990s indicate that the larger firms might be able to push prices a little less than 40% above competitive levels. However, pressure from a regulator, the potential for entry, and the generators' high share of production under fixed-price contracts meant that they did not actually raise prices to this extent.

In early 1994 the regulator within Britain successfully pressured these two firms to divest some of their coal- or oil-fired plants that tend to set the prices. Simulations of the English market suggest that a small reduction in these firms' capacity could significantly help consumers at relatively low costs. Moreover, more aggressive policies to increase the number of firms could substantially improve the industry's operation. If the industry could be revamped into five approximately equal-sized firms, most of the price disparity and lost economic welfare due to imperfect competition could be eliminated. In designing more liberalized markets, it is important in the initial stages to establish enough firms for effective competition.

Simulations also reveal that accelerating new entry into a market dominated by a few producers may have mixed effects if new capacity is not justified on cost grounds at the time. Economic welfare improves slightly with small amounts of entry but deteriorates at higher levels of entry. These policies provide benefits by pushing prices downward and increasing output toward their competitive levels. However, if the costs of building and operating a new plant are greater than the avoided costs of an existing plant owned by one of the large firms, these additional investment costs must be subtracted from the benefits before determining the net outcome of the policy. Such a condition may arise because prior to the investment, the longer-term market price will exceed the cost of the most expensive unit that remains producing (the marginal unit) when imperfect competition prevails. Entry decisions are based on prices, but welfare depends on costs.

Nordic Power Markets

One Swedish producer, Vattenfall, owns approximately 50 percent of Swedish production and about 20 percent of Nordic generation from Norway, Sweden, Finland, and Denmark. Under current conditions, this firm has some incentives to reduce their nuclear-generation capacity to influence prices. Simulations by Halseth suggest that a reduction of 25% in its generation could raise prices by 15% above competitive levels. The income earned on the production it continues to produce are sufficient to offset the income lost of the nuclear generation that is removed. In addition, while integration of these markets will move Norwegian and Swedish prices closer to each other, the analysis suggests that Swedish prices will fall only modestly, as Vattenfall seeks to protect its profits from sharp price reductions.

These estimates show the potential for price manipulation, but firms may be motivated by other factors in determining their output levels. Given the political debate about the desirability of nuclear power in Sweden, owners of these plants would be reluctant to sharply reduce their operations to seek higher revenues.

The main Norwegian generator, Statkraft, does not possess similar incentives to reduce output. It costs this firm very little to produce additional power from their existing hydroelectric plants; thus, their extra or additional (marginal) costs on these units are very low. Thus, it requires a more steeply rising price from controlling output to justify the removal of some of its generation,

California's Industry

A potential exists for market power in high-demand hours within California. The fall and early winter months present the most severe problem due to the relative scarcity of hydroelectric power within California and the Pacific Northwest. Native demand within the northwest absorbs most of the available hydroelectric power during these key hours, allowing little of it to be available for export to meet California demand under these conditions.

In one set of estimates by Borenstein and Bushnell with a moderate demand response to price, peak prices are about 65% higher than competitive levels in March while other prices range from 1 to 5 percent more. In September, peak prices are 31% higher while the other prices range widely from 3% to 73% more.

A key transmission bottleneck creates congestion along Path 15 that sometimes disconnects northern and southern California. The Borenstein-Bushnell simulations indicate that in high-demand hours of the fall and early winter months, competitive firms within northern California provide insufficient capacity relative to total demand in this region to prevent large producers there from raising prices.

Market power in California is most severe when the consumers' response to price is relatively low. In certain critical hours, prices can rise sharply in the simulations and can be several times higher than their competitive levels. Uncertainty exists about how responsive consumers are and whether firms are seeking to maximize their income over the short or long run. In addition, policymakers can influence this response. Offering real-time price information and improving the availability of certain end-use technologies can make consumers more responsive to price, thereby helping to mitigate market power problems.

California's largest producers are divesting most of their plants and increasing the number of firms competing in the new market. This divestiture significantly lowers the potential for market power in the simulations. The availability of hydroelectric power and the response of demand to price may also have a significant influence on market prices.

Transmission Pricing Policy

Workably competitive power markets depend on ready access to transmission and distribution lines that connect regionally dispersed end-users with generators. A country or state will benefit most if governments adopt rules that allow many market participants to compete, thereby fostering economic efficiency. Instead, strong political interests are setting rules in some regions, thereby sculpting rules in their own interests and at the expense of overall economic efficiency. An example may be the recent pricing rules adopted within Texas that discourage long-distance competition from generators located far away from important demand centers. Here, regulators have explicitly raised the costs of long distance transmission, but not local users, although actual economic costs will not rise with distance if electricity is sent against the prevailing flow. The traditional approach for recovering costs in a declining-cost industry like electricity transmission has been through postage stamp adders applied relatively equally to each user.

Electric transmission is a network where the costs at one location depend upon what is happening elsewhere. The location of generation & loads affects the amount of lost power. Transmission constraints can prevent cheaper plants from operating. Prices that ignore these interactions will result in higher operating costs and poorly located generation and loads. Some regions have recently adopted prices that reflect these costs but most have not. Prices that vary by location are known as nodal pricing. A node exists on the system where power can be either injected or used.

Comparisons of models for existing transmission systems are difficult because the economic and technological characteristics of regional systems can differ significantly from each other. For this reason, the group focused attention on comparing different regional approaches for setting transmission pricing rather than on existing transmission models. The group focused on six principles (Table 1) for guiding the design of transmission policy in different countries and states. The first principle listed in Table 1 is concerned with short-run economic efficiency, the second through fourth with long-term efficiency, and the last two with implementation.

Table 1: Principles for Transmission Pricing

- Promoting the efficient day-to-day operation of the bulk power market
- Signaling locational advantages for investment in generation and demand
- Signaling the need for investment in the transmission system
- Compensating the owners of existing transmission assets
- Simplicity and transparency
- Political implementation (feasibility)

Promoting Daily System Operation

A power system would quickly break down if some entity does not coordinate all the generators. Outside of hydroelectricity, electric power cannot be stored. The coordinator must ensure that total generation equals total demand at every instant for reliability purposes. In promoting efficient daily operation, a coordinator tries to meet the system demand at the lowest possible cost. If all generation and loads occurred at the same location, a coordinator would schedule the lowest-cost units first. Scheduling must be done in a way that maintains system reliability, including having sufficient excess generation to meet surge demands and sudden power outages.

Once generation is dispersed, efficient system coordination requires the inclusion of the cost of transmitting power from one location to another. These costs include not only the actual cost of system losses but also the opportunity costs imposed by transmission constraints. Transmission losses are an actual cost in that someone must pay for the generated power that is lost as heat when it is transmitted through the wires. On the other hand, transmission constraints represent an opportunity rather than an explicit cost or expenditure outlay. Constraints force a more-expensive generator to replace a less-expensive one. In the process, the system foregoes opportunities to provide more power less expensively. Whatever happens, the actual dispatch must be feasible, taking account of the transmission constraints.

Countries have adopted different approaches for incorporating these trans-

Opportunity costs are the forgone opportunities of a particular action. For example, a student attending a college must pay direct expenses for tuition and books. In addition, the student often incurs an opportunity cost because he or she yields the opportunity to earn a wage at a full-time job. Although not a direct expenditure by the student, these costs are real and must be included in the full costs of attending college. In a similar manner, the full costs of using an electric transmission line should include the lost opportunities of producing and carrying power more cheaply, even though a user may not pay these charges in some pricing systems.

mission costs. In determining the spot price of electrical energy in the day and hour preceding the delivery of power, the markets in England and Wales essentially ignore these costs and view all generation as being at a single point. When actual delivery occurs and constraints are realized, the coordinator may need to change the dispatch to relieve the constraints. It is a relatively simple system, but it can cause the real-time dispatch (at the time of delivery) to be badly inferior if the losses and constraints are significant.

Representing a second approach, power markets in Norway and Texas essentially pretend that all generation is at one point but administratively impose charges for transmission losses. Generators must bid prices that include these transmission losses as well as their additional or marginal generation costs. In Norway, these charges for transmission losses are administratively imposed by node and season. If congestion becomes a problem in Norway, this system price becomes a reference price. Price zones are defined administratively and regional prices are determined to clear these markets according to the constraints. This general approach for these systems appears to reduce administrative costs by simplifying transmission prices but it may lead to some problems in real-time dispatch in systems where losses and constraints change quickly or significantly.

Finally, one can choose generation based upon an explicit system model that includes these losses and constraints, as has been introduced in New Zealand. Generators provide the coordinator with their price bids, which should cover their marginal (or incremental) generation costs. The coordinator runs the system model to produce a schedule for when and where to operate plants and at what spot prices. Generators receive the spot price at their location on the system (or node), which includes the losses and constraint costs. The system automatically incorporates losses and constraints in determining the best schedule for plant operation and the best set of prices.

The possibility of market power among generators can influence the efficiency of any of these three approaches for charging for transmission losses and congestion. Some generators may bid their plant prices sufficiently higher than their marginal costs during certain times to attract additional revenue. The interaction between market power and transmission pricing and access is an important issue that requires additional future analyses.

Most market designs have focused on rewarding lower-cost over higher-cost generation. They have not paid the same attention to discouraging lower-valued end uses that may constrain the system at critical times and in key regions. Systems that simplify consumer prices (e.g., uniform prices across large zones) are politically popular but may sacrifice considerable economic efficiency. When rules allow consumers to pay a relatively uniform price across locations, they will demand too much power in high-cost locations and too little power in low-cost locations. In this respect, economically efficient generation schedules depend upon both consumers revealing their preferred prices and producers revealing their actual costs.

Signaling Investment in Generation and Loads

Although these short-run operations of existing plants and transmission are important to incorporate properly, there exist longer-run gains in economic efficiency that must also be reflected. Over time, it may be possible to reduce transmission costs by influencing the location of plants and loads on the system. In some cases, moving generation and sales closer to each other may reduce costs. In other cases, locating plants and loads in a way that relieves the use of congested transmission lines may be more economically efficient.

A system that allows transmission costs to influence the prices paid by consumers and received by producers may allow sufficient incentives for locating these investments properly. Firms and customers will locate in a way to reduce their transmission costs if their expansions are small relative to the overall system. When they are sufficiently bigger, prices will change throughout the system, causing the current spot prices to be a poor guide for economically efficient decisions.

Most electrical systems do not allow their electricity prices to vary with the cost of congestion and losses. Nevertheless, they frequently have some pricing mechanisms that encourage production to locate closer to anticipated growth in electricity demand. In England and Wales, for example, transmission access charges favor the injection of new plants in the south near London or they favor expanding electrical loads in northern England. However, the incentives may not be large enough to incorporate the full costs of locating generation and consumption in these different regions.

Expanding Transmission

Prices by location can also signal the need for investment to expand the transmission system, although most countries do not use such prices to guide investment. A significant price differential between nearby locations indicates that it is costly to transport electricity between these two points, perhaps due to congestion along the line linking them. A new line will reduce these costs and improve the efficient allocation of electricity. However, investment that relieves congestion will change prices and erode the price differentials. The investor will be unable to receive the income from these large price differences along the system, once the investment is made. Under these conditions, firms will not invest in transmission capacity unless they receive some type of capacity or fixed payment contract in advance.

Transmission congestion contracts are financial instruments that hedge the price differentials between nodes. When such contracts are in place, they allow participants to base their decisions on relatively stable prices by location. A key issue here is the length (number of months or years) of these contracts; investors require relatively long periods to achieve their returns.

Long-term investment will also require new institutions that establish clear ownership or decision rights over expanding the system or that identify the right user coalition that will benefit from an expansion. The entity responsible for operating the system on a daily basis need not necessarily be the one that invests in its expansion.

Compensating the Owners of Existing Transmission Assets

Owners of existing transmission assets need to be compensated. Transmission charges are usually set to recover historic costs. Use of 'signaling' prices would recover only a fraction of the allowed revenues. If a system uses 'signaling' prices, it must impose a large additional charge on each location's price to raise sufficient revenues. In some cases, this additional charge can be sufficiently large as to hide the incentives provided by 'nodal' prices.

Simplicity and Transparency

Transmission prices should be understandable if they are to provide useful signals. This need may or may not require that pricing be simple. Users may not understand complex approaches for calculating price differentials but may need to know only the few prices that affect them. At the same time, users may not have much faith in simple approaches that do not represent actual costs accurately.

The 'contract-path' pricing used in New England and in other systems until the recent past underscores simplicity. Each transmission-owning utility has a postage stamp wheeling charge per unit of power (kilowatt-year). This charge might be computed by dividing its cost of transmission by its peak demand. In arranging power exchanges across regions, any individual utility would need to negotiate a contract path across intervening systems and pay each its wheeling charge. In practice, such transactions affect power flows on other systems, but these additional effects would neither receive nor make payments (depending upon whether their costs were increased or reduced by the transaction).

Political Implementation

Some proposed pricing systems can not be implemented because too many influential interests are likely to lose. For example, existing transmission pricing often suppresses regional differences in costs, a practice that may have to continue to avoid creating winners and losers.

Another example may be the penalties recently imposed upon long-distance transmission in Texas. The state government will recover 70% of the transmission costs through a postage stamp and 30% through a technique that combines the change in electricity flow and distance. A long-distance transaction which increases the flows on a large number of lines will have to pay a large fee (which is economically efficient). The problem is that a transaction in the opposite direction, which would actually reduce flows and costs, would have to pay the same large fee, creating an unjustified deterrent for distant generators wishing to enter local markets.

Energy Sector and Environmental Impacts

The restructuring of the electric power industry should significantly change the industry's regulation and the way generators dispatch, operate, add and remove capacity, price and market electric power. These changes could fundamentally change electricity prices and demand and alter the eventual fuel mix of electric generation, which could either increase or reduce environmental emissions. This section discusses some of the basic fundamental factors determining the broader impacts of restructuring on energy markets and on the environment.

Existing Estimates of Changes in Pollution

Several earlier studies for the United States estimated the resulting changes in nitrogen oxides (NO_x), carbon dioxide (CO_2), and other potential pollutants that might result from having more competitive electric power markets. All studies indicated increased pollution levels, principally from increased coal use, that frequently were several percentage points higher than their baseline values over the next 5 to 10 years. During this period, many owners of existing Midwestern coal plants find that they can refurbish their existing plants and operate them more cheaply than those who seek to finance and operate new gas-fired plants. Over time, however, total electricity demand grows, eventually creating the need for new capacity. In this latter period, new gas-fired plants are likely to enjoy advantageous capital and operating costs in many regions.

The major problem with mid-west coal in this transitional period is carbon dioxide. Stringent carbon standards will make it uneconomic to retrofit existing coal facilities. If carbon standards are not implemented during this period, coal-fired generation should compete favorably in this region, even when meeting other new environmental standards.

No studies estimate increases in sulfur dioxide (SO_2) because these emissions fall under a national cap regardless of shifts in fuel use by electric power companies. However, increased coal use could increase the demand for, and hence the costs of meeting, these SO2 emissions targets.

The range of increased CO2 emissions varies substantially by study. Some projections anticipate relatively small increases in national CO_2 emissions. As an example, the 1996 environmental impact statement from the US Federal Energy Regulatory Commission expected national emissions in the year 2000 to range from about 3 to 28 million tons of carbon higher than their baseline scenario. These increases are relatively small compared to the level of commitment that the United States might make under many international proposals. However, Palmer and Burtraw provide other estimates that assumed greater growth in transmission capacity and accelerated retirement of nuclear plants. Their projections estimate national CO_2 levels that were several times larger, ranging between 75-134 million tons. The higher end of these latter estimates could equal 50% of the reductions needed by the year 2000 under the Climate Change Action Plan. Estimates vary with key assumptions not only across studies but also across scenarios within a particular study.

A similar range exists for the effect on national NO_x emissions levels by the year 2000. Once again, the FERC estimates remain relatively low, varying between 71 and 128 thousand tons. The Palmer-Burtraw study places this estimate at a higher range of 112 to 479 thousand tons, and several other studies estimate an even greater increase. Although these changes may appear large, they are relatively minor compared to the approximate 2 million ton reduction in national NOx emissions that are anticipated from the Clean Air Act Amendments.

The environmental impacts of electricity restructuring in other countries may be very different and depend upon the types of reform policies under consideration as well as on the underlying energy market conditions. In 1996 and 1997 Japanese integrated utilities contracted with independent power producers for 6 gigawatts (GW) of electric production to begin operation between 1999 and 2004. The Environment Agency of Japan estimates that this additional production will increase annual CO_2 emissions by 3 to 4 million tons of carbon, which equals about 1% of total CO_2 emissions in 1990. Current IPP plans for units that will begin operating by 2004 include 45% coal-fired and 43% residual oil-burned plants. However, gas-fired units should become more important as utilities and MITI, the regulator, pursue environmental regulation more aggressively.

Privatization and regulatory reform in England and Wales exposed that country's high-cost domestic coal resources to intense competitive pressure, substantially reducing both the use and price of that fuel. The English and Wales restructuring improved the efficiency of existing plants and replaced high-cost domestic coal by natural gas. During the transition toward privatization between 1990 and the 1994-95 period, the emission levels of the major pollutants declined. CO_2 levels fell by 28%, SO_2 levels declined by 35%, and NO_x pollution tumbled by 38% (Newbery and Pollitt).

Environmental issues will attract considerably more attention in the future. Even for a single country or region, many existing projections differ noticeably depending upon their methodologies and assumptions. In addition, there may be conditions that cause a restructured electricity market to improve the environment. Structured analysis based upon large-scale models of electricity and fuel markets will help to discern the relative impact of the interactions between these separate effects.

Restructuring and Environmental Protection

If further analyses continue to find increased pollution from the sweeping changes expected in the electric power markets, it should be understood that the issue of environmental protection can be separated from the issue of restructuring electricity markets. Restructuring is not the source of possible increased pollution. Rather, the problem arises from failing to force generators to account for the external costs associated with additional generation from older plants. Governments can design policies that would protect the environment without hindering the restructuring process. Moreover, economic measures like emissions trading may be a more attractive policy alternative under conditions of competitive power markets than under the previous rules for allocating costs and setting prices with cost-of-service regulation.

If a few large producers dominate an electricity market, they may be able to sustain prices above competitive levels. Higher prices should reduce electricity demand and its associated pollution levels. The net effect on the environment, however, must also incorporate how the exercise of market power influences the generation mix. An important area for future research will be to estimate the environmental effects of restructured electricity markets that are dominated by a few large producers.

In the past, policymakers have feared several possible sources for increased pollution from restructuring:

- Competitive pressures may favor an increased use of existing coal plants, especially older more polluting units.
- Total electricity demand could increase, particularly if electricity costs and prices should fall with restructuring.
- Some higher cost but less polluting generation sources (e.g., renewables and energy efficiency programs) may become more difficult to introduce into the electric system when units are bidding on the basis of costs.

While each of these factors may contribute to greater pollution, there are other factors that may help to offset and even reverse these effects. Some of the impacts favoring greater pollution appear more pronounced in the earlier years while other impacts contributing to pollution reductions are more important in later years. This uncertainty associated with a diverse set of factors makes it quite difficult to develop precise estimates for the environmental impacts of restructuring. Moreover, a major difficulty in comparing existing estimates of the net emissions impacts is that analyst's definitions of what would happen in the absence of restructuring (or their baseline assumptions) can often be quite different. For example, some analysts already include in their baseline scenario wholesale trade (or wheeling) between large electrical systems.

These complications may mean that it is easier to discuss the major conceptual issues than to provide precise empirical estimates. Table 2 contains a set of factors that could either increase or decrease the expected environmental emissions resulting from electricity restructuring efforts. This list serves as a useful background for the more indepth discussion below.

Expanding Coal Use in Existing Plants

When generation plants compete against each other and the transmission system allows a freer flow of electricity trade between systems, there will be pressures to switch electric production towards the available plants that are relatively inexpensive to operate. This redispatch of electric generation will favor the expanded use of coal-fired plants built in the 1957-77 period. These are the plants with available capacity and apparently low operating costs relative to other units. (This effect is already happening to some extent and can be mainly attributed to the wholesale competition between large electrical systems. It can therefore be partly taken into account as a baseline assumption in analyses which are restricted to the effects of competition in retail power markets.)

Although a more competitive industry is expected to increase utilization of existing coal plants in the near term, there are limits on this expansion. An important factor is that coal use is already growing under the baseline assumptions, thereby constraining the amount of excess coal plant capacity in the future. Additionally, although the accounting costs of operating coal plants more intensively appear modest, the actual economic costs of expanding production could be substantially higher in units that have not been well maintained and continuously upgraded over time. For example, heat rates and reliability in some such plants may not be that good, and for smaller plants, the manpower costs or environmental expenditure per kWh may be

Table 2: Influences of Restructuring on Environmental Impacts

Key factors that might *increase* emissions due to restructuring include:

- Increased utilization of more pollution-intensive (primarily coal-fired) power plants due to economic redispatch, lower operation and maintenance costs, and increasing baseload production in response to demand shifting from peak to offpeak periods;
- Economic retirement of nuclear plants prior to their scheduled license expirations; and
- Greater overall sales of electricity due to lower prices without offsetting declines in nonelectric fuel use.

Key factors that might *reduce* emissions due to restructuring include:

- Faster penetration of more efficient supply technologies (primarily natural gas-fired combined cycle plants);
- Economic retirement of the most costly fossil-fired plants;
- Successful marketing of 'green power' and end-use efficiency services as part of a differentiated, high-value electricity product;
- Improved efficiencies at existing plants; and
- Legislative requirements for new renewable energy sources and/or conservation investments.

higher than for larger, newer units. This issue requires careful future monitoring.

Access to Transmission Capacity

Another constraint on expanded coal use is the availability of interregional transmission capacity between high-producing and high-consuming areas. Much of the low-cost coal generation cannot be dispatched to other regions if critical transmission links are not in place.

Measuring existing transmission capacity and estimating the potential expansion of that capacity will influence estimates of projected environmental emissions. National-level analyses that exclude regional transmission constraints show more substitution of higher polluting generation sources for lower-polluting ones. (The results also depend upon other assumptions, such as NO_x emission rates and nuclear displacement. For example, the regionally-based Palmer and Burtraw study assume a much lower NO_x emission rate for older coal plants than does the previous nationally-based study by Lee and Darani. Please see the notes at the end of this paper.) Conversely, regional analyses which assume little or no growth in transmission capacity could understate this substitution.

Understanding which factors determine new investment in transmission capacity is not well understood at this point. Profitability, ownership of the transmission entity, and other institutional constraints will help to shape this response. It will also make a difference whether the new investment occurs as a new set of transmission wires or as enhancements of capacity on existing lines. It should be acknowledged that the economics of transmission expansion are poorly represented in current large-scale models.

Increased competition should lead to the retirement of uneconomic units and the addition of new, more efficient capacity. Owners will retire those plants with high operating costs or whose expansions would be too risky to assume. In this way, capital will be replaced differently than under baseline planned retirement schedules. What happens to emissions depends on what types of units are retired. If nuclear units are replaced by fossil-based systems recently built or located in another region, total CO_2 and NO_x emissions will increase because the nuclear systems do not emit these pollutants. If economically inefficient fossil-fueled units are retired, the impact on emissions will be less and can even be a net environmental gain in certain circumstances.

New Entrants and More Natural Gas Use

Restructuring is also spurring the addition of new gas combined-cycle units that should reduce emissions. Rapidly improving efficiencies and declining costs are fostering this new entry. Smaller-sized units are more flexible to build and use during uncertain times.

Although natural gas transmission capacity appears adequate to support increased gas sales for power generation, higher demand for this fuel could raise natural gas prices. Offsetting this pressure, however, competition between electricity and natural gas at the end-use level may prevent gas prices from rising much. If electricity prices fall with restructuring, some industrial and commercial users will shift away from natural gas toward electrically based technologies. This shift will partially offset the increased gas use for power generation, thus dampening the upward pressure on natural gas prices.

Operating Efficiency and Electricity Demand

The ability of firms to retain profits will change incentive structures, possibly leading to changes in plant operations, cost and performance. Operating costs could be reduced through workforce reduction, contracting, or adoption of cost-cutting methods from other firms. Plant operations could become more efficient, and plant availabilities could be increased, with both performance indicators tending toward a ‘best practice frontier’. The effects of such changes on net emissions depend on the relative advantage for specific types of plants. This factor is usually incorporated as a set of exogenous assumptions in modeling.

Restructuring is likely to lead to lower electricity costs and prices, although two factors could operate in the opposing direction. First, large producers may be able to sustain prices above competitive-cost levels if they own and exercise a monopoly power advantage, as discussed previously. And second, many restructuring programs within the United States allow owners of existing plants to collect a special unavoidable payment from all users of the electric system for recovering the difference between their historical asset costs determined under the old regulatory structure and the new market-determined prices. These additional costs, known as “stranded” costs, are added to the costs of supplying electric power under the new conditions to determine the prices paid by consumers.

If the electricity price should decline, one would expect an increase in consumer demand for electricity. Stranded-cost recovery is scheduled to decrease over time, which increases the chances of lower electricity prices and greater electricity consumption after a few years. In addition, prices may fall further with declining market power as new companies over time enter previously regulated utility areas, although mergers may dampen this competition in certain instances. Growth in electricity demand, stimulated by lower electricity prices, will increase pollution if it represents new demand for energy. On the other hand, substitution from other fuels to electricity, stimulated by lower electricity prices, need not involve increases in pollution. Analyses that do not include the reduction of fuels outside the electricity sector will overstate the environmental impacts of restructuring.

Current knowledge about the price responses of different types of consumers at different times is extremely uncertain. This is one of the most important empirical questions for ongoing research. Emissions changes due to demand growth will moderate over time because the mix of available capacity to meet the new demand will shift toward high-efficiency natural gas plants. If consumers switch to electricity from other sources of energy, the growth in pollution will not be as large and may even be negative, depending upon the emissions characteristics of the replaced fuels.

New pricing regimes under restructuring will also provide price signals reflecting the cost of producing and consuming electricity at different times. Time-differentiated (or real-time) pricing could also lead to a short-term increase in emissions but the case is more complex than for a simple decrease in overall prices. There will be more use of real time pricing in the future, especially when the cost of metering falls and data collection and processing technologies improve. These conditions will lead to higher peak-period prices and lower off-peak-period prices than under traditional utility pricing. Consumers may respond to these new conditions by replacing some peak demand with use at other times. The system's load profile will flatten, requiring greater use of baseload plants relative to peak-load plants. In the near term, the available baseload capacity would be existing coal plants compared to peak-period gas-fired generation. These conditions will lead to an increase in emissions. However, natural gas combined cycle plants will compete for baseload demand over the longer term, thereby diminishing this impact.

Renewables and Energy Efficiency

Although the cost of renewable energy production remains above market levels, it has declined in recent years. A more competitive industry is expected to increase the pressure on these costs. In addition, some renewable technologies can be located closer to the eventual end-use location, thereby eliminating some or all of the transmission and distribution costs. Opportunities to sell such generation, referred to as distributed resources, could grow if market forces begin to shape electricity prices.

Increased risk associated with a movement away from cost-of-service regulation will increase the cost of capital for power suppliers and will make capital-intensive renewable energy technologies more expensive than natural gas combined cycle sources. The future of renewable energy will depend on continued government support unless a great demand for 'green power' develops (as discussed below). Many proposals at the state and federal level contain some type of renewable supply mandate such as a Renewable Portfolio Standard. To the extent that these programs result in higher penetration of renewables such as solar, wind and biomass than otherwise would have occurred, environmental emissions will fall. The extent of this potential effect requires further analysis, including several key design issues for renewables support programs. These include evaluation of supply mandates versus financial or tax subsidies; inclusion of existing versus new capacity; definition of qualifying technologies; and mechanisms to locate capacity where it will have the most beneficial environmental effect.

End-use efficiency and conservation investment, which have been supported by public programs such as demand-side management (DSM), have been increasingly turned over to private markets during the transition to competition. In a competitive power market, some new firms selling electric power to consumers could obtain exclusive rights to a particular end-use equipment. Offering the customer exclusive use of this equipment to reduce his energy costs may be an effective way to differentiate a firm's product in the marketplace. Such programs may provide critical incentives to develop better technology that is also cost effective.

At the same time, however, these technologies and programs will not do well when their costs exceed the market rate for power. Some regions or states may opt to include these programs as additional unavoidable costs for consumers, as is done currently for the "stranded-cost" recovery, but the higher costs of these programs will become more visible than in the past. Assumptions about demand reductions from public programs or market-driven activities will probably remain as exogenous assumptions in current and future analysis.

Retail competition will allow consumers to vote with their wallets about how they want their electricity to be produced. As producers seek to differentiate their product offerings, many are considering offering electricity from environmentally friendly sources, or "green power". Consumer preferences will thus play a direct role in determining the electricity supply mix for the first time. To the extent that demand for green power leads to greater penetration of renewable energy sources, emissions will fall. The extent of this demand is extremely uncertain, as is the ability or desire of consumers to distinguish between types of power supply and whether these supplies are new or existing (i.e. a repackaging of resources which does not alter the system profile). The effects of green power marketing programs on air emissions are thus highly uncertain and depend on a number of factors, including the baseline market penetration of such services, the types of renewables which comprise a green power offering, and the location and timing of any new resource additions.

Environmental Policy

The impact of competition on the environment is likely to be closely guarded by a number of environmental regulations. The nature of environmental regulation varies among pollutants and this has important implications for the expected impact of industry restructuring.

Sulfur dioxide (SO_2) is subject to a nationwide cap, implemented through a program of tradable emissions permits (the Acid Rain Program). Restructuring in the electric power sector thus will not result in a higher level of total emissions than allowed under the program. However, it could increase the costs of SO_2 control and the market-clearing price of permits if it were to increase the demand for SO_2 emissions. It could also affect changes in the timing of emissions, resulting from the flexibility allowed through banking of excess emissions reductions.

Nitrous oxides (NO_X) are currently subject to regulation based on emissions per unit of fuel input. Thus, sources can increase their emissions as their output increases. Restructuring could lead to increased emissions of NO_X, and in the short to medium term these could be significant in certain parts of the US. However, it is possible that a partial cap on NO_X emissions could be developed prior to 2005, and such a cap is already in place in the Ozone Transport Region (OTR) covering 13 Northeastern states and the District of Columbia. The EPA has recently issued a proposal which would set 5-month summer NO_X caps, or budgets, for 24 states covering more of the Eastern US. The future of this proposal depends on the actions of the states and the EPA under the Clean Air Act and is not certain. (The Acid Rain program is specifically authorized by Congress; no such statute exists for NO_X trading).

Greenhouse gas emissions (GHGs) are currently unregulated and any increases due to restructuring would not be mitigated by federal or state law. Depending on the timing and magnitude of potential GHG emissions increases, efforts to meet current voluntary goals and potential future commitments could become more difficult and costly. Conversely, GHG emissions decreases through competitive effects or policy interventions would make control efforts less difficult and costly.

Mercury emissions are usually not considered in analyses of restructuring. As a hazardous air pollutant (HAP), mercury is regulated under Section 112 of the Clean Air Act. At present there is no direct regulation of mercury emissions from power plants, so any increase resulting from restructuring (which could only occur if more coal is used) would not be mitigated. Pilot programs for mercury control, and banking of emissions reductions, are underway in the Great Lakes region.

In general, restructuring is likely to improve the performance of incentive-based environmental policies such as emissions allowance trading, through better incentives for cost minimization. Conversely, the costs and environmental consequences of less efficient environmental policies are magnified.

To the extent that negative environmental impacts occur as restructuring of the electric power industry takes place, these impacts are not the result of restructuring per se. Instead, the problem arises from the failure to require electricity generators to account for the external costs associated with pollution, whether it comes from current plant operations or changes in operations under competition. Governments can design policies that would protect the environment without hindering the restructuring process. Examples include such price instruments as tradable permits or more quantity-oriented policies as the National Ambient Air Quality Standards (NAAQS), which place an absolute cap on emissions in non-attainment areas. In most cases these policies would be equally applicable to other sectors of the economy.

Modeling Electricity Markets

Models of electricity and fuel markets are extremely helpful in determining the range of possible outcomes for electricity prices, the fuels used for generation, and the associated environmental impacts. They provide an important framework for allowing analysts to understand how supply and demand conditions develop over time and how they combine to set market-based prices. The models useful for understanding developments in a market-based electricity industry are fundamentally different from those that served people well under a cost-of-service regulatory regime.

At the core of each model is a set of existing generation plants with varying cost and engineering characteristics. Much of the model depends upon how it incorporates improvements in operational and maintenance costs, the factors determining the retirement of existing plants, and the addition of new entrants employing advanced technologies. Demand characteristics that link electricity consumption to electricity and competing fuel prices, economic growth, and population are also very important. And finally, transmission linkages between producing and consuming areas and the setting of transmission and distribution charges form the all-important network channeling electricity supply to the relevant consumers.

Summary

The emerging competition in the electric power sector raises a number of important policy and strategic issues. Alternative market designs will create different opportunities for both incumbent and new firms. Some designs will promote economic efficiency more than others will.

While economic modeling focuses on only a subset of issues, it can improve basic understanding of different implications for both strategic and policy decisions. In this report, we have discussed three such problems: (1) the incentives for and the impact of exercising control over electricity prices by large producers, (2) the effect of different transmission and wholesale market rules on electricity prices, and (3) the broader impacts of restructuring on energy markets and on the environment. Application of models to these and other problems will require constant monitoring of assumptions and understanding of different general approaches.

Notes

This report focuses on the primary discussion among the Energy Modeling Forum working group on electricity competition and therefore excludes a number of other important issues under the restructuring topic. Where appropriate, we briefly mention here a few important sources on some of these topics.

A well-written background book on restructuring within the United States can be found in T.J. Brennan, K.L. Palmer, R.J. Kopp, A.J. Krupnick, V. Stagliano, and D. Burtraw, *A Shock to the System: Restructuring America's Electricity Industry*, Washington, DC: Resources for the Future, 1996.

Paul L. Joskow, "Restructuring, Competition, and Regulatory Reform in the U.S. Electricity Sector," *Journal of Economic Perspectives, 1997,* 11(3): 119-138, emphasizes the importance of generation and transmission complementarities in designing the cost-of-service regulatory approach that the current competitive model is trying to replace. He emphasizes the key issues that need to be addressed in the near, mid, and long term in improving economic efficiency.

David M. Newbery, "Power Markets and Market Power," *Energy Journal*, 1995, 16(3): 39-66, discusses the emergence of market power as England and Wales privatized its electricity industry.

William W. Hogan, "A Market Power Model with Strategic Interaction in Electricity Networks," *Energy Journal*, 1997, 18(4):107-141, discusses the problem of market power along a congested transmission system and how such behavior can result in expansions rather than reductions in the firm's production level.

The estimates of market power for different countries are drawn from several sources, including papers discussed at the Energy Modeling Forum working group meetings. For the English and Welsh markets, the estimates are drawn from Richard Green, "Increasing Competition in the British Electricity Spot Market, *Journal of Industrial Economics,* 1996, 44(2): 205-216. See also, Richard J. Green and David M. Newbery, "Competition in the British Electricity Spot Market," *Journal of Political Economy*, 1992, 100 (5): 929-953. For the Nordic markets, the findings are extracted from Arve Halseth, "Market Power in the Nordic Electricity Market," January 1997, ECON Centre for Economic Analysis, Oslo, Norway. See also Eirik S. Amundsen, Lars Bergman, and Bo Andersson, "Competition and Prices on the Emerging Nordic Electricity Market," in *International Energy Markets, Competition and Policy,* Proceedings, 18th Annual North American Conference, San Francisco, September 7-10, 1997, pp. 30-39. And finally, the California results are based upon those discussed by Severin Borenstein and James Bushnell, "An Empirical Analysis of the Potential for Market Power in California's Electricity Industry," January 1997, University of California Energy Institute, Berkeley, California.

The discussion in the section, "Transmission Pricing Policy", draws very heavily from the useful paper by Richard

Green, "Electricity Transmission Pricing: An International Comparison" *Utilities Policy*, 1997, 6(3): 177-184. This special issue of that journal carries a number of papers by other EMF participants conducted as part of the current EMF study that describe a particular country's experiences with transmission pricing and emphasizing the six principles identified in this report.

Karen Palmer and Dallas Burtraw, "Electricity Restructuring and Regional Air Pollution," *Resource and Energy Economics*, 1997, 19: 139-174, provide a useful discussion of their own modeling work on the environmental impacts and compare their results with previous studies on that topic. The other studies on national impacts reviewed by Palmer and Burtraw include: (1) US Federal Energy Regulator Commission, 1996, *Environmental Impact Statement, Promoting Wholesale Competition through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Cost by Public Utilities and Transmitting Utilities*, April; (2) Rosen, R., Woolf, T., Dougherty, B., Biewald, B., Bernow, S., Regulatory Assistance Project, 1995, *Promoting Environmental Quality in a Restructured Electricity Industry*, prepared for the National Association of Regulatory Utility Commissioners, Tellus Institute, Boston, December 15; and (3) Lee, H. and Darani, N., 1995, *Electricity Restructuring and the Environment*, CSIA Discussion Paper 95-13, Kennedy School of Government, Harvard University, December.

The discussion of the environmental impacts of privatization and restructuring in England and Wales is drawn from David M. Newbery and Michael G. Pollitt, "The Restructuring and Privatisation of the CEGB: Was It Worth It?" *Journal of Industrial Economics*, 1997, 45 (3): 269-303.

Participating Modeling Organizations

A number of modeling organizations reported on their approach and results in analyzing electricity restructuring and its impact on market power, transmission pricing, and the energy market and environmental impacts. We would like to particularly acknowledge the significant contributions of individuals from the following organizations:

- AES Corporation (Virginia)
- Altos Management Partners (CA)
- UC Berkeley
- U. Cambridge (UK)
- Caminus (UK)
- U. Canterbury (NZ)
- Catholic U. (Chile)
- Center for Clean Air Policy
- CORE (Belgium)
- CRIEPI (Japan)
- Data Resources Inc.
- ECON (Norway)
- Electric Power Research Inst.
- Harvard
- U. Illinois
- LCG Consulting (CA)
- London Business School
- Mass. Inst. of Technology
- OnLocation (Virginia)
- Resources for the Future
- Stanford
- U. Texas
- U. Toronto
- US Department of Energy, Policy
- US Energy Information Admin.
- US Environmental Protection Agency