Restructuring the U.S. Electric Power Sector:

A Review of Recent Studies

by

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EXECUTIVE SUMMARY

The restructuring of the electric power industry has been described as "one of the largest single industrial reorganizations in the history of the world." Over the past 10 to 15 years, state and federal policies have broken up and reorganized electric utilities, replaced administrative oversight with markets, created new institutions to coordinate the separated generation, transmission, and distribution stages, encouraged entry of new unregulated suppliers and marketers, and generally sought to unleash competitive forces. As with deregulation and reform of other industries, electricity restructuring was intended to produce cost efficiencies and price benefits to consumers. Whether it has achieved its stated objective is the focus of a number of recent studies that are examined in this review.

The 12 studies covered in this review are listed at the end of this summary and include the most comprehensive, prominent, and oft-cited evaluations of electricity restructuring. They differ in numerous important ways, most importantly, in their methodologies and their conclusions. The focus of this review has been on the strengths and limitations of their specific methodologies and, hence, on the confidence one might place in their conclusions. The methodologies used in these studies fall into three categories:

Four of the 12 studies compare prices before and after restructuring, or with and without restructuring, based on econometric models of price determination. That is, they represent pricing as a function of causal variables, estimate the relationship, and contrast actual prices with predicted prices in the absence of restructuring. Studies employing this technique are those authored by Cambridge Economic Research Associates; by Joskow; by Taber, Chapman, and Mount; and by Fagan.

Five studies compare prices (or costs) under restructuring relative to what they would have been in the absence of restructuring, but without using econometrics as the method for estimating prices without restructuring. Rather, they construct the latter from accounting data or through simulation techniques. These comparative studies are authored by the Center for the Advancement of Energy Markets; by Apt; by Synapse; by Global Energy Decisions; and by Energy Security Analysis, Inc.

The remaining three studies are more descriptive in their approach and also more selective in their focus. These studies –by Weaver; by the ISO/RTO Council; and by the N.Y. State Department of Public Service–evaluate the impact of single companies or institutions involved in restructured electricity markets.

With respect to their conclusions, these studies arrive at quite different results. Nine of the 12 find that there have been retail price benefits or cost efficiencies from restructuring. Some of the studies drawing this conclusion make clear that their conclusions are qualified and tentative, whereas others are quite sweeping and expansive. The three remaining studies report no benefits or even outright consumer costs from restructuring. Of course, any overall judgment

or conclusion is not simply a matter of counting the number of favorable versus unfavorable studies. Rather, that depends upon the reliability of each particular study, and that in turn on the soundness of its methodology.

This report begins by setting out the basic methodological approaches employed in public policy evaluation. It then discusses some deficiencies that characterize the methodologies in most of these studies. The three most common and major deficiencies of these studies are as follows:

First, there is a lack of precision about what is meant by "restructuring." Some studies recognize that restructuring has involved a series of policy actions occurring over time and at different rates in different regions, and attempt to capture that complexity. Others, however, treat restructuring as a discrete event that occurred at a single point in time. That latter approach over-simplifies restructuring and mischaracterizes the data.

Second, many studies overlook the fact that the post-restructuring prices in many states are the result of rate reductions and freezes, stranded cost adjustments, and excess capacity. All of these factors mean that post-restructuring prices are actually administratively set and not at all a reflection of the permanent or equilibrium market price. Studies that fail to look beyond these initial transition effects give a misleading impression of the effects of restructuring.

Third, while most studies recognize that many other factors besides restructuring affect prices, not all are careful to control for those other influences. For example, studies that control only for natural gas prices, or select a very small number of particular states for comparison are unlikely to isolate the effect of restructuring correctly. Other studies that use models based on prices in the 1990s are unlikely to project accurately after 2000 when natural gas costs were far higher. These mistakes can result in incorrectly attributing price effects to restructuring.

In addition to these deficiencies that are common to many studies, each study has its own specific limitations. Among the econometric-based studies, we note the rudimentary representation of "restructuring" and of price determination in the study by Cambridge Energy Research Associates (CERA), together with the poor predictive power of its model. Both the CERA and Joskow studies fail to adjust their price data for price freezes or stranded costs, resulting in an overstatement of apparent "benefits" in the post-restructuring period. Both Taber et al and Fagan rely on models that are too simplistic, on definitions of "restructuring" that are crude or incorrect, and on statistical techniques that are inadequate to their task.

The comparative studies by the Center for the Advancement of Energy Markets (CAEM) and by Global Energy Decisions (GED) do not adequately specify what they mean by "restructuring" and in addition fail to control adequately (or sometimes at all) for other possible influences on the price differences that they measure. The CAEM study, along with those by Apt and GED, makes no corrections for the temporary effects of freezes and excess capacity. Indeed, CAEM explicitly assumes that these effects are permanent, while the GED study's estimated benefits consist almost entirely of temporary effects. The Apt study employs a measure of price effects that seems poorly chosen, while Energy Security Analysis, Inc., relies on a "black box" simulation that yields some paradoxical results.

Among the three descriptive studies, Weaver's analysis seems as uniformly critical of Enron as the ISO/RTO Council report uniformly praises RTOs. The report by the New York Department of Public Service is not much more balanced, and none of these three purports to be a comprehensive evaluation of restructuring.

These observations and many other comments about the studies are documented in this review. Also noted are some instances in which studies are commendably careful to acknowledge their limitations, and some methods by which these studies might be improved. On the other hand, this report explains that most studies pay too little attention to three other factors that should be part of any comprehensive assessment of restructuring. These are as follows:

First, restructuring has been accompanied by market power, market manipulation, and numerous mergers among utilities. These concerns are scarcely mentioned in most studies, even though a full accounting of restructuring should address all the costs and risks of reforms, such as the loss of vertical integration savings and the increased risk of market power abuses, as well as any benefits.

Second, there is much concern in the industry, but little recognition or discussion in these studies, about the rising costs of regional transmission organizations (RTOs), inadequate RTO governance processes, and the failure of RTOs to deal with transmission congestion or to successfully encourage new investment in the grid. Again, these issues should be part of any comprehensive assessment of restructuring.

Third, while these studies seek to identify and measure cost efficiencies from strengthened profit incentives, none addresses the potentially adverse effects of restructuring on service quality and reliability effects. Present evidence on this issue is sparse, but from other experiences with deregulation, there is reason for concern and additional investigation.

This report therefore concludes that the methodologies used in these studies consistently fall short of the standards for good economic research. In addition, most of these studies fail to fully address the effects of restructuring. These deficiencies call into question the conclusions reached by existing studies of restructuring. In particular, despite much advocacy, there is no reliable and convincing evidence that consumers are better off as a result of restructuring of the U.S. electric power industry.

STUDIES REVIEWED

Apt, Jay. "Competition Has Not Lowered U.S. Industrial Electricity Prices." *Electricity Journal*, 2005.

Cambridge Energy Research Associates. Beyond the Crossroads: The Future Direction of Power Industry Restructuring. 2005.

Center for the Advancement of Energy Markets. *Estimating the Benefits of Restructuring Electricity Markets: An Application to the PJM Region*. September 2003.

Energy Security Analysis, Inc. *Impacts of the PJM RTO Market Expansion*. November 2005.

Fagan, Mark. "Measuring and Explaining Electricity Price Changes in Restructured States." *Electricity Journal*, June 2006.

Global Energy Decisions. *Putting Competitive Power Markets to the Test: The Benefits of Competition in America's Electric Grid*. July 2005.

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Joskow, Paul. "Markets for Power in the United States: An Interim Assessment." *Energy Journal*, January 2006.

New York State Department of Public Service. *Staff Report on the State of Competitive Energy Markets: Progress To Date and Future Opportunities*. March 2006.

Synapse Energy Economics. *Electricity Prices in PJM: A Comparison of Wholesale Power Costs in the PJM Market to Indexed Generation Service Costs*. June 2004.

Taber, John, Duane Chapman, and Tim Mount. "Examining the Effects of Deregulation on Retail Electricity Prices." Cornell University Working Paper, February 2006.

Weaver, Jacqueline. "Can Energy Markets Be Trusted? The Effect of the Rise and Fall of Enron on Energy Markets." *Houston Business and Tax Law Journal*, 2004.

I. INTRODUCTION

For most of its history the U.S. electricity sector has been dominated by large, vertically integrated, and heavily regulated utilities. The natural monopoly characteristics of the industry, its enormous economic importance, plus concerns about corporate abuses and mergers led to state and federal regulation of investor-owned utilities and to public ownership throughout much of the 20th century. Beginning in 1978, however, reforms made inroads on this traditional structure and operation of the private sector of this industry. By the late 1990s a transformed industry had started to take shape, characterized by substantial de-integration, significantly looser regulation, and more market-oriented operation. Major problems with restructuring in California and elsewhere stalled further reforms, but the industry nonetheless has been changed profoundly.

The promise of electricity restructuring was that it would result in competition that would in turn produce cost efficiencies in production and lower prices to retail consumers. Over the past few years, a number of studies have been conducted assessing the extent to which restructuring is meeting its objectives. The 12 studies covered in this review represent perhaps the most prominent of these recent efforts. Each is subject in this paper to a detailed evaluation of its methodological soundness and the reliability of its conclusions. In brief, this review finds significant deficiencies in all of these studies and thus no convincing evidence that restructuring has produced its intended benefits.

Among the challenges facing these studies is the complexity of electricity restructuring in this country. Unlike restructuring or deregulation in other industries such as telecommunications or airlines, electricity reforms have involved several different policy initiatives adopted at different times, by different government levels, and often phased in over a long period. The first restructuring initiative dates back to the Public Utility Regulatory Policies Act (PURPA) of 1978. It sought to promote energy conservation by requiring traditional utilities to purchase cogenerated power. PURPA also promoted wholesale power transactions between utilities. While PURPA demonstrated the feasibility of a broader market for wholesale power, it also highlighted the difficulties of ensuring access by buyers and sellers to the transmission grid required to transact power over longer distances.

The limitations on access to the transmission grid were one motivation for the passage of the Energy Policy Act of 1992 and the orders issued by the Federal Energy Regulatory Commission (FERC) in 1996 pursuant to the 1992 Act. FERC Orders 888 and 889 required utilities to file non-discriminatory "open access" tariffs for their transmission services and eliminated the sequential marking up of transmission charges that hindered long distance transactions. While these policies had some effect in prying open access in some regions, continued ownership and operating control of the transmission grid by the integrated utilities thwarted realization of full access to the transmission system.

As a result, four years later, FERC Order 2000 sought to wrest operating control of the transmission grid from the traditional utilities by promoting regional transmission organizations

(RTOs). Shortly thereafter FERC proposed a Standard Market Design that sought not only to improve transmission access, but also to encourage regional energy markets. In principle, FERC intended that all utilities in a region would turn over control (but not ownership) of their transmission infrastructure to an RTO. The RTO would operate the transmission lines on behalf of all market participants. RTOs have fostered broader and deeper wholesale markets, but they do not exist in all regions and even where they do exist, their record of success has been mixed and their management controversial. More recently yet, FERC has signaled its interest in exploring alternative methods of achieving efficient and effective management of the transmission grid.

Complementing federal actions promoting competition in wholesale markets have been a number of state initiatives in retail markets. Many states have required or promoted divestiture of generation assets from transmission and distribution by the traditionally integrated utilities. The purpose of such separation was to eliminate any competitive advantage for the incumbent owner of distribution and transmission, thereby at least theoretically opening up the market to multiple independent generation suppliers.

In addition, a number of states, beginning in 1996 with the high electricity cost areas of New England and California, have allowed entry by competitive or alternative electricity providers. These competitive providers are essentially marketers of power that is generated by others and ultimately distributed to final customers on lines that continue to be owned and operated by the local distribution utility. The latter then become strictly "wires" businesses, although in practice they are generally required to offer default electric service (purchased from generation companies) to customers who do not choose another provider. Finally, at the retail level, restructuring has been accompanied by rate freezes or other agreements designed to ensure benefits to customers during the initial few years of the program.

In short, all of these changes were intended to create alternative sources of power for wholesale and retail customers. The plan was to foster competition among independent generators by creating a level playing field for wholesale power transactions that permitted retail customers and local distribution utilities to shop for power supply. All this was expected to lower wholesale costs and retail prices.

By the year 2000, about half the states either had restructured their electricity sectors or were planning to do so. The transmission grid was increasingly operated by RTOs and in some places relatively free of artificial constraints. While the problems in California and elsewhere brought further restructuring to a halt, many states were irreversibly committed to deregulation and, in any event, reforms at the federal level continued. The result is that electricity restructuring is substantially complete in some regions of the country but has scarcely affected other regions.

Because the changes to electricity markets varied over time and by state or region, a useful exercise would seem to be a comparison of prices or costs between states that have restructured and those that have not, or between pre-restructuring years and the post-restructuring period. In this manner it is in principle possible to assess the impact of reforms and determine whether expectations about cost and price effects are being met. Most of the 12

studies reviewed here do precisely this. This review focuses on the methodological soundness of these studies and on the reliability of their conclusions.

The 12 studies, together with brief notations concerning their authorship, methodologies and conclusions, are listed in Table 1.[1] Of these 12, nine offer some type of quantitative assessments of the benefits of restructuring in which actual numerical measurements are made of the price (or in two instances, cost) effects. Four of those nine studies–by Cambridge Economic Research Associates, Joskow, Fagan, and Taber et al–employ econometric models of electricity pricing. These involve reliance on the economics of price determination and statistical estimation of a formal model.

Five other studies provide quantitative estimates of the effects of restructuring but without formal modeling. These are authored by the Center for the Advancement of Energy Markets, Apt, Synapse, Global Energy Decisions, and Energy Security Analysis, Inc. The final three studies–those by Weaver, the ISO/RTO Council, and the State of New York--present descriptive accounts of other issues relating to restructuring, but do not involve formal modeling or other quantification.

Apart from their methodological differences, these studies also differ substantially in their fundamental conclusions. As shown in Table 1, nine of these studies offer essentially favorable assessments of electricity restructuring, three of those with substantial qualifications. Three other studies come to negative conclusions. Any ultimate assessment of restructuring, of course, does not depend so much on how many studies come to each conclusion, but rather which of them is convincing as a result of using sound methodology. This report is devoted to the determination of their soundness.

To that end, this review begins with a discussion of various methodologies that are commonly used in economic evaluations of policies like restructuring or deregulation. That is followed by an analysis of three significant methodological deficiencies that characterize many of these studies. The individual studies are then assessed in three chapters that group them according to their essential approaches–those based on econometric modeling, those using other quantitative methods, and the descriptive studies. The final substantive chapter raises some additional effects of electricity restructuring that are relevant to a comprehensive assessment but are either not addressed or receive inadequate attention in these studies.

With respect to the nine quantitative studies of electricity restructuring, we conclude that, in various ways and to varying degrees, these studies fail to meet the standards of good economic policy research. Several are flawed to the point that they should not be given any credence, and most of the others should be viewed with considerable caution. This body of evidence provides no basis for the view that restructuring has succeeded in achieving its intended purposes.

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[1] Full citations to these studies as well as to several related items also evaluated in this report can be found in the Appendix.

TABLE 1
Listing of Major Studies Reviewed

Study, Report or Article	Author	Date	Methodology	Brief Conclusion
Estimating the Benefits of Restructuring Electricity Markets: An Application to the PJM Region	Center for the Advancement of Energy Markets	September 2003	Comparison of residential, commercial, and industrial prices for PJM states, net of price changes in 3 non-restructuring states, 2002 relative to 1997	Substantial savings found in restructuring PJM states
Electricity Prices in PJM: A Comparison of Wholesale Power Costs in the PJM Market to Indexed Generation Service Costs	Synapse Energy Economics	June 2004	Comparison of actual wholesale generation prices for three PJM utilities to implied costs under regulation in 1996/1997 projected forward to 1999/2003	Actual costs less than implied regulated costs, although not necessarily large differences
Can Energy Markets Be Trusted? The Effect of the Rise and Fall of Enron on Energy Markets	Jacqueline Weaver, *Houston Business and Tax Law Journal*	2004	Discussion of Enron's role in creating and operating in deregulated energy markets, especially in California	Energy markets cannot be trusted
Putting Competitive Power Markets to the Test: The Benefits of Competition in America's Electric Grid.	Global Energy Decisions	July 2005	Comparison of actual prices to simulated prices based on constructed costs under regulation Eastern Interconnection, 1999-2003	Substantial consumer benefit from restructuring
Impacts of the PJM RTO Market Expansion	Energy Security Analysis, Inc.	November 2005	Simulation of power flows and resulting costs within expanded PJM, 2005	Significant cost reductions in larger control area
The Value of Independent Regional Grid Operators	ISO/RTO Council	November 2005	Discussion of benefits and costs of ISOs/RTOs	ISOs/RTOs perform many necessary functions at costs that level out with time and size

TABLE 1

Study, Report or Article	Author	Date	Methodology	Brief Conclusion
Competition Has Not Lowered U.S. Industrial Electricity Prices[1]	Jay Apt, *Electricity Journal*	March 2005	Comparison of rates of change in industrial prices before and after restructuring to rates of change without restructuring, by state and region, 1990-2003	Restructuring not significantly related to differences in rates of price change
Beyond the Crossroads: The Future Direction of Power Industry Restructuring.	Cambridge Energy Research Associates	2005	Econometric model of overall electricity prices in 1981-97, for four regions, used to predict 1998-2004 prices	Predicted prices below actual prices in all regions. Index of deregulation related to savings, except in West
Markets for Power in the United States: An Interim Assessment	Paul Joskow, *Energy Journal*	January 2006	Econometric model of industrial and residential rates by state, 1970-2003	Variables for retail competition and share of exempt wholesale generation both associated with lower retail prices
Examining the Effects of Deregulation on Retail Electricity Prices	John Taber, Duane Chapman, Tim Mount, *Cornell University Working Paper*	February 2006	Econometric model of overall, residential, commercial and industrial prices, by utility, 1990-2003	Variables for membership in auction-based ISOs not associated with lower prices
Staff Report on the State of Competitive Energy Markets: Progress To Date and Future Opportunities	New York State Department of Public Service	March 2006	Discussion of progress and plans for restructuring New York's retail electric and gas markets	NYISO working well, with wholesale competition benefits, plus lower retail prices and entry of power marketers
Measuring and Explaining Electricity Price Changes in Restructured States	Mark Fagan, *Kennedy School Working Paper*	June 2006	Econometric model of industrial prices in 1990-97, by state, used to predict prices in 2001-03	Predicted prices higher than actual in restructuring states than without restructuring, but effects dominated by other factors

[1] The same research is also reported in a Carnegie-Mellon working paper with the same title.

II. ASSESSING DEREGULATION: PROCEDURES AND PITFALLS

Economics is routinely used to perform assessments of the effects of regulation or deregulation of various industries. Here we review standard methodologies for conducting such studies, highlighting the strengths and limitations of each. We then discuss three major methodological problems shared by most of the studies being evaluated.

A. Empirical Methodologies

The economics literature recognizes four major approaches to assessing the performance effects of regulation and deregulation.[2] The first and perhaps most obvious approach is a direct comparison of regulated and unregulated firms and markets. Such studies can be either cross-sectional–for example, across states with and without regulation--or time-series, say, during a period when regulation begins or ends. In either case, attention must be paid to (1) what constitutes the regulatory difference or change that arguably affects performance, (2) the exact date of change in regulation or deregulation, (3) any non-policy factors that need to be controlled for, and (4) the possibility that those states that choose to deregulate differ in some way that alters the effects of the policy.

The second approach is to examine the effects of variations in the intensity of regulation across time and place. This approach is particularly well suited to the circumstance where complete deregulation may not have occurred but regulation varies in its stringency across firms or markets. In this case with proper modeling and attention to all the above considerations, one can measure the effects of the degree of change or the difference in regulation that is observed. It may even be possible to project the effects of full deregulation based on the partial effects that have occurred.

Third, where actual data are unavailable, inadequate, or otherwise compromised, a controlled experiment is a possible means of predicting the effects of deregulation. Such an experiment in principle might be a field experiment or a laboratory experiment. Confidence in the results of a laboratory experiment may be tempered by the complexity of the regulation examined, the sophistication of the experimental design, and the ability to capture other factors that may be relevant to the outcome of regulation.

Fourth and lastly, one might estimate an industry model based on underlying demand, cost and other relevant behavioral relationships. A well-specified and well-estimated econometric model may provide the basis for predicting the effects of deregulation, but of course it is dependent on the availability of good data, correct model specification, and resolution of any econometric issues. Alternatively, simulation of a well-specified model with correct parameters is an accepted, although less common, approach to measuring likely regulatory effects.

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[2] This discussion borrows heavily from Paul L. Joskow and Nancy L. Rose, "The Effects of Economic Regulation" in *Handbook of Industrial Organization Volume II* edited by Richard Schmalensee and Robert D. Willig, The Netherlands: Elsevier Science Publishers, 1989.

The studies reviewed illustrate all of these approaches except for controlled experimentation.[3] Straightforward comparisons lie at the heart of studies by CAEM and Synapse, for example, while Joskow and Apt employ formal econometric modeling. The study by ESAI focuses on only one dimension of restructuring, while that by Global Energy encompasses nearly all aspects. In a number of respects, however, none of these studies satisfies all the important criteria for methodological soundness. The next chapters are devoted to the specific issues affecting each study. Here we begin with a discussion of three major failings that are common to many of these 12 studies.

B. Pitfall #1: Defining Electricity Restructuring

We begin with the most basic of problems–the lack of precision in what is meant by "restructuring." The studies reviewed here vary enormously in their definition of the reforms that they study, and indeed some do not offer a specific definition at all. But absent a clear and consistent meaning of restructuring, its effects will not be isolated and measured consistently.

One reason for such variation and ambiguity is that, in contrast to industries such as airlines and perhaps telecom, electricity restructuring was not a single event that occurred at one point in time. It was the cumulative result of several quite different policy actions taken over a considerable period of time. Moreover, some of the policies did not trigger sudden change but rather phased in the changes, or allowed them to occur, over an extended interval. These factors make "restructuring" a rather complex phenomenon to study.

The studies reviewed here deal with this multiplicity of reform events and the lack of precise timing in a variety of ways, some more satisfactorily than others. Some acknowledge the multiple dimensions of reform, creating separate variables for the major policy actions and even using continuous variables to capture the progressive nature of the consequences of certain actions. An example of this is Joskow's use of the percent of supply coming from exempt wholesale generators, something that reflects the gradual progress of competition better than a simple discrete ("yes-or-no") variable for when such generators were first allowed.

In contrast, other studies such as those by CERA and Fagan treat restructuring as if it consisted of a single event that occurred at one point in time. Often in such studies a single year is chosen to represent deregulation in its entirety. This approach fails to capture the actual effects of restructuring by incorrectly characterizing its multi-faceted and time-dependent nature. Portraying restructuring as a dichotomous event may result in the failure to detect a true effect of restructuring, or seeming to find one where none exists.

An extreme version of this is illustrated by the Global Energy Decisions study, which, despite the multiplicity of reforms over time, assumes that "restructuring" necessarily involves all of them simultaneously. The presumption that merchant generation, open access, retail competition, and RTOs represent some kind of indivisible policy bundle is unfounded and gives

[3] Controlled experiments have been used in electricity markets in other contexts, however, such as pilot programs and test cases for time of use pricing.

rise to a distorted measure of the consequences of reform.

Clearly, therefore, these studies interpret restructuring or deregulation in a variety of quite different ways. The most satisfactory of these explicitly recognize and measure the several dimensions and phased timing of policies that constitute "restructuring" in this industry. Much less satisfactory, sometimes to the point of distorting events, are studies that treat the process as if it were a single event occurring at one point in time.

C. Pitfall #2: Post-Reform Price

The second major pitfall in electricity reform studies concerns the prices used for comparison.[4] In assessments of deregulation or regulatory reform in most industries, the post-reform price is obvious, and the challenge is to identify the comparable pre-reform price. In the case of electricity, however, the post-reform price is itself often distorted, so that comparisons to it are invalid as guides to the effects of restructuring. There are three reasons why post-reform prices may not be correct measures: rate reductions and freezes, stranded costs, and excess capacity. Each of these merits discussion.

(1) RATE REDUCTIONS AND FREEZES

As previously noted, several New England states and California initiated state-level restructuring in 1998, with many more states following over the next several years. Restructuring typically involved several distinct elements, notably, divestiture of generation assets, provision for stranded cost recovery, and initial rate reductions followed by freezes. By 2003 some 64 rate reduction and freeze plans were in effect in nearly half the states.[5] Initial rate reductions ranged from 3 to 20 percent, ensuring immediate gains to consumers. Freezes extended from two to ten years, during which time consumers would be guaranteed little or no price change regardless of utilities' underlying costs. If costs fell as expected, unchanged retail price could at least be expected to generate excess funds to help pay utilities for their stranded costs.

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[4] Several of the studies examine other outcome measures besides price or cost, for example, generator heat rates or market liquidity. We do not focus on them in this report since, if these represent important actual performance improvements, they should ultimately manifest themselves in cost or price benefits. Indeed, it would be double counting to measure both the source of efficiency gain and its direct cost effect. In addition, the promise of restructuring was that costs and prices would show improvement. For these reasons we focus on price and cost effects.

[5] *2002 Performance Review of Electric Power Market*, Ken Rose and Venkata Bujimalla, Review Conducted for the Virginia State Corporations Commission, August 2002.

In fact, costs unexpectedly rose as natural gas prices spiked in 2000-01 and wholesale auction prices for electricity rose. This forced utilities and their regulators to deal with frozen retail rates that in many cases no longer covered utility costs. Many state utility commissions responded by allowing utilities to book as "deferred balances" those costs that exceeded revenues from the frozen rates. These deferred balances, which often grew to be quite substantial, could then be charged to ratepayers as soon as the rate freeze expired. The effect of this arrangement was to keep retail prices below their equilibrium level temporarily, but after expiration of the freeze, those prices would jump substantially in a "catch-up" phase.

The implications of this for measuring the impact of restructuring are illustrated in Figure 1. This shows a hypothetical jurisdiction that embarked on restructuring in year t. Prior to that time, retail rates were increasing at a modest rate indicated by the slightly upward slope to the line. Suppose that annual rate of increase was 3 percent. At time t, an initial rate reduction of 5 percent was agreed to, with a three-year period of frozen rates. Clearly, comparing rates in years t+1 or t+2 to those in t-1 or t-2 would give a very favorable view of "restructuring." An even more favorable view would result from projecting rates for years t+1, t+2, and t+3 based on the pre-restructuring trend. That would imply that rates would have continued to rise at 3 percent per year, giving the dotted line in Figure 1.

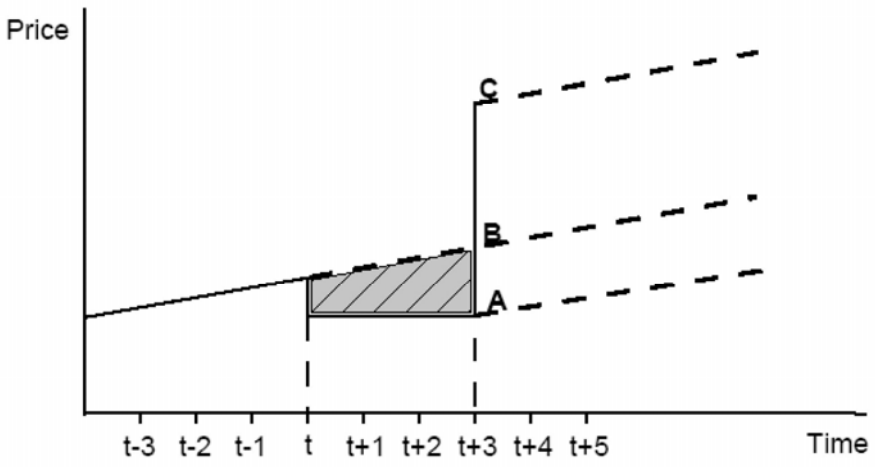
While the rate reduction and freeze indisputably conferred an initial benefit, the flaw in the comparison is apparent when the rate freeze expires in year t+4. At that time, the new rate need not begin rising at the old 3 percent rate from the point A, where price ends up at the end of the freeze. One possibility is that price immediately jumps back to point B, where it would have been absent the freeze, and then resumes rising at 3 percent per year. That would imply that consumers would see a rate rise in year t+4 of approximately 12 percent–the three-year catch-up plus the "usual" 3 percent increase. Beyond that, the utility might seek recovery of its unanticipated cost increases during the rate freeze period. That would mean that in year t+4 it would seek an increase sufficient to generate an additional amount of revenue equal to the shaded area, resulting in a potentially enormous year over year rate change, say, point C. The actual consequences of this entire scenario for consumers requires much more careful analysis of the entire time path of prices and an understanding of the counterfactual.[6]

The experience of the state of New Jersey is instructive. The Electric Discount and Energy Competition Act established a four-year transition program beginning in August 1999. It imposed initial rate reductions of 5 percent, growing to 10-14 percent, together with inflexible rate caps (apart from some cost pass-through) for the states' four utilities. Almost immediately, those utilities incurred losses. The regulator responded by permitting them to accumulate deferred balances, which grew to approximately $1 billion by 2003. This amount was approximately equal

[6] For example, one might smooth the entire rate reduction/freeze/spike and calculate something like an annualized rate of increase. Such calculations are made more complicated by the fact that in many instances utilities and state commissions agreed on a two or more year period over which deferred balances would be recovered.

Figure 1

Example of Retail Rate Reduction, Freeze, and Freeze Expiration



Typical retail rate plan with reduction at time t and three-year rate freeze. Shaded area is value of temporary rate reduction relative to likely alternative prices indicated by dotted line in periods t through t+3. Possible price paths after expiration of freeze are denoted by dotted lines rising from points A, B, or C.

to the estimated benefit of frozen rates, leading the state's Deferred Balance Task Force Report to conclude: "It is very possible that ratepayers, on net, would have saved more without the combination of rate caps and delayed pass-through that caused the accumulation of deferred balances and interest payments."[7]

Table 2 summarizes available information on those state plans where freezes have already expired. It shows the substantial price increases that have occurred in a number of utilities' service territories immediately upon expiration of their rate freezes. The most striking and controversial cases involve Connecticut Light and Power, Pike County Light and Power in Pennsylvania, and Baltimore Gas and Electric, which filed for rate increases in excess of 70 percent upon expiration of the freezes.[8] These sudden rate hikes make clear that the earlier period frozen prices were an administrative arrangement–perhaps even a simple postponement of changes--rather than equilibrium prices.[9]

Despite the fact that observed post-reform prices in states with freezes were divorced from underlying costs and hence not reliable guides to market equilibrium, several studies, including those by Taber et al and Fagan, use price in just that way and without qualification. Their methodologies are therefore invalid. Other studies, such as that by Global Energy, note the existence and influence of rate freezes, but proceed nonetheless to perform calculations that make no adjustment for them. Those studies are incomplete and their conclusions subject to revision. Yet other studies (for example, that by Apt) use industrial rather than residential rates for purposes of analysis, claiming that rate reductions and freezes were directed at residential users. That argument is incorrect, however, as shown in Table 2. Industrial rates have been subject to rate reductions and freezes in perhaps half the cases. While those have often not been of the same magnitude or duration, reliance on industrial rates as reflecting equilibrium is misplaced.

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[7] Executive Summary of the Deferred Balances Task Force Report, Trenton NJ, 2002, p. 13.

[8] As this is written, state regulatory commissions have modified these requests by allowing smaller rate increases over more years as an equivalent method of cost recovery. Electricity consumers in Illinois have recently been informed of rate increases ranging from 22 to 55 percent in January 2007. "Energy Auction in Illinois Will Lead to Jump in Rates for Consumers," *The Wall Street Journal*, Sept. 18, 2006, p. A8.

[9] It may be possible to infer what rates would likely have been in the absence of the freeze by smoothing the price path during the years of the freeze together with the post-freeze catch-up years. The annual rate of change across all those years might approximate the counterfactual price for comparison purposes.

TABLE 2
Summary of Information about Expired State Retail Plans *

State	Investor-owned utilities/distribution companies	Beginning of rate freeze/rate cap	End of rate freeze/rate cap	Initial rate reductions	Rate changes after expiration **	Comments
AZ						
	Arizona Public Service Co.(APS)	since 1999	until 2005	7.5% for residential and small business customers; 5% for large customers	Initial increase: 4.21%	Power supply adjustment beginning April 2006
CA						
	San Diego Gas & Electric Co.	since 1998	1999	10% for residential and small commercial	NA	
	Southern California Edison	since 1998	until 2002	10% for residential and small commercial	1) March 2001. "As much as" 42% rate increase 2) January 2006. 8.5%	
	Pacific Gas & Electric	since 1998	until 2002	10% for residential and small commercial	1) March 2001. "As much as" 46% rate increase 2) January 1, 2006. 11% for residential	
DC						
	Potomac Electric Power Co. (PEPCO)	2000	February 1, 2007 for low-and moderate-income customers; January 1, 2005 for all other residential and commercial customers	7% - residential; 6.5% - non-residential	1) Feb. 8, 2005. Residential rates increased on an average annual basis by 17.7%; small commercial by 24% 2) June 1, 2006. Residential increased on annual average by 12%; small commercial by 10%	
CT						
	Connecticut Light and Power	2000	Rates were capped until December 31, 2003 (Standard Offer Period)	Reduction of 10% until 2003	72% between 2003 and 2006	
	The United Illuminating Co.	2000	Rates were capped until December 31, 2003 (Standard Offer Period)	Reduction of 10% until 2003	20% between 2003 and 2006	

TABLE 2 (cont'd)
Summary of Information about Expired State Retail Plans

State	Investor-owned utilities/distribution companies	Beginning of rate freeze/rate cap	End of rate freeze/rate cap	Initial rate reductions	Rate increases after expiration **	Comments
DE						
	Delmarva Power & Light Co. (Connectiv)	1999	until May 2006	7.5% for residential	2003. 1% increase due to merger. May 1, 2006. 59% for residential and small commercial	Increase will be phased in over several years
	Delaware Electric Cooperative (DEC)	1999	until March 31, 2005	5%	6-8% since rate freeze was lifted	Rates are expected to increase further once long-term power purchasing contracts expire in 2007
MD						
	Baltimore Gas & Electric (BG&E)	since July 2000	December 31, 2003 - expired for non-residential; June 30, 2006 - expired for residential	6.5% for residential	1) 2004. Total bill increased by 17% for small commercial 2) July 1, 2006. Total annual bill increase of 72% for all residential	Increase of 2006 will be phased in over several years
	DPL/Connectiv (DPL)	since July 2000	June 31, 2003 - expired for non-residential; June 30, 2004 - expired for residential	7.5% for residential	1) 2004. Average annual bill increased by 12% for residential; decreased by 5% for small commercial 2) 2005. Total annual bill increased by 5.8% 3) June 1, 2006. Total annual bill increase of 35% for all residential	Increase of 2006 will be phased in over several years
	Potomac Electric Power Company (PEPCO)	since July 2000	June 30, 2004 - expired for residential	7% for residential; 4% for others	1) 2004. Total bills increased by 16% for residential and small commercial 2) 2005. Overall annual bill increased by 4.6% 3) June 1, 2006. Total annual bill increased by 39% for all residential	Increase of 2006 will be phased in over several years
MA						
	Boston Edison	since March 1998	Standard Offer Supply (SOS) until March 2005	Reduction of 10% from 1997 rates, followed by a further 5% reduction by September 1999	1) March 1, 2005. 5.18% for residential; 20% for commercial. 2) January 1, 2006. 25-34% for residential. 3) March 2006. Decrease in rates of commercial and industrial customers by 50%	Rate increase information is incomplete because residential rates change every six months

TABLE 2 (cont'd)
Summary of Information about Expired State Retail Plans

State	Investor-owned utilities/distribution companies	Beginning of rate freeze/rate cap	End of rate freeze/rate cap	Initial rate reductions	Rate increases after expiration **	Comments
	Cambridge Electric	since March 1998	SOS until March 2005	Reduction of 10% from 1997 rates, followed by a further 5% reduction by September 1999	1) March 1, 2005. 2.18% for residential; 20% for commercial. 2) January 1, 2006. 25-34% for residential. 3) March, 2006. Decrease in rates of commercial and industrial by 50%	as above
	Commonwealth Electric	since March 1998	SOS until March 2005	Reduction of 10% from 1997 rates, followed by a further 5% reduction by September 1999	1) March 1, 2005. 3.02% for residential; 20% for commercial. 2) January 1, 2006. 25-34% for residential. 3) March 2006. Decrease in rates of commercial and industrial by 50%	as above
	Eastern Edison	since March 1998	SOS until March 2005	Reduction of 10% from 1997 rates, followed by a further 5% reduction by September 1999	March 1, 2005. 6% for residential; 20% for commercial	as above
	Fitchburg Gas and Electric	since March 1998	SOS until March 2005	Reduction of 10% from 1997 rates, followed by a further 5% reduction by September 1999	1) March 1, 2005. 5.18% for residential; 20% for commercial. 2) Dec. 1, 2005. 31% for residential	as above
	Massachussets Electric Co.	since March 1998	SOS until March 2005	Reduction of 10% from 1997 rates, followed by a further 5% reduction by September 1999	1) March 1, 2005. 6% for residential; 20% for commercial 2) Novermber 1, 2005. 27.5% for residential.	as above
	Northeast Utilities (Western Massachusetts Electric Company)	since March 1998	SOS until March 2005	Reduction of 10% from 1997 rates, followed by a further 5% reduction by September 1999	March 1, 2005. 13.63% for residential; 20% for commercial	as above
MI						
	Consumers Energy Co.	since May 2000	Dec. 31, 2003 - expired for large industrial; Dec. 31, 2004 - for all other business customers; Dec. 31, 2005 - for residential	5% for residential	Upon expiration of residential price caps utility increased base rates by $86 million.	

TABLE 2 (cont'd)
Summary of Information about Expired State Retail Plans

State	Investor-owned utilities/distribution companies	Beginning of rate freeze/rate cap	End of rate freeze/rate cap	Initial rate reductions	Rate increases after expiration **	Comments
	Detroit Edison Co.	since May 2000	Dec. 31, 2003 - expired for large industrial; Dec. 31, 2004 - for all other business customers; Dec. 31, 2005 - for residential	5% for residential	9% for residential	
NJ						According to Citizens Utility Board, electric rates at the four NJ utlities have increased between 30 and 40% since the auctions began in 2002
	Conectiv	since August 1999	until August 2003	10.2% reduction phased in over 4 years	1) August 2003. 8.1% increase for residential 2) June 1, 2006. 12.5% for residential (BPU's projection)	Rate increase information is incomplete; rates are set by auction under staggered 3-year contracts
	GPU	since August 1999	until August 2003	11% reduction phased in over 4 years	1) August 2003. 3.3% for residential 2) June 1, 2006. 12.4% (BPU's projection)	as above
	PSE&G	since August 1999	until August 2003	13.9% reduction phased in over 4 years	1) August 2004. 15.1% increase for residential (PSE&G's projection) 2) June 1, 2006. 13.7% (BPU's projection)	as above
	Rockland	since August 1999	until August 2003	11.6% reduction phased in over 4 years	1) August 2003. 15% increase (PSE&G's projection) 2) June 1, 2006. 12% for residential (BPU's projection)	as above
NY						Different terms of restructuring for all state's utilities
	Central Hudson	since 1998	Frozen at 1993 rates through June 30, 2001	25% for large industrial phased in 5 years (5% reduction per year)	NA	

TABLE 2 (cont'd)
Summary of Information about Expired State Retail Plans

State	Investor-owned utilities/distribution companies	Beginning of rate freeze/rate cap	End of rate freeze/rate cap	Initial rate reductions	Rate increases after expiration **	Comments
	Consolidated Edison	since 1998	2003 for large industrial	Immediate 25% decrease for large industrial, to remain fixed for five years; 10% decrease for all other customers phased in over 5 years	NA	
	New York State Electric and Gas (Energy East)	since 1998	2003	25% for industrial and large commercial (five reductions of 5% each); 5% for residential and small commercial/industria consumers phased in over 5 years	NA	
	Orange & Rockland Utilities	NA	until May 1, 1999	4% for residential, 4% for commercial and 14% for industrial in 1995-1996. This was followed by two 1% reductions, in 1997 and 1998, for residential and a 8.5% drop in 1997 for large industrial	NA	
	Rochester Gas and Electric	since 1998	2002	Residential and small commercial - 7.5%, other commercial and most industrial - 8%, large industrial - 11.2%; all reductions phased in over five years	NA -	
OH						
	Monongahela Power Co.	2001	Dec. 31, 2005 for residential; 2003 for large industrial	5% reduction for residential on the generation portion of the bil		Mon Power's customers were transfered to AEP's subsidiary and will be charged the Columbus Southern rates which are frozen through 2008

TABLE 2 (cont'd)
Summary of Information about Expired State Retail Plans

State	Investor-owned utilities/distribution companies	Beginning of rate freeze/rate cap	End of rate freeze/rate cap	Initial rate reductions	Rate increases after expiration **	Comments
PA						Two rate caps. Total rates were capped at January 1, 1997 levels for 54 months, and the generation portion of the rate was capped for 9 years or until the time the utility no longer was recovering its stranded costs
	Duquesne Light	1999	until March 2002	State did not require reductions	1) March 2002. Utility announced that it had recovered its stranded costs and would reduce rates by 16 to 20%. 2) August 2004. Generation rates increased 11.5% for residential and small commercial for 2005-2007 period.	
	Pike County Light & Power	1999	Dec. 31, 2005	State did not require reductions	January 2006. Increase of 70%	

Sources:
Utilities' press releases;
State commissions' press releases;
APPA web site http://www.appanet.org/aboutpublic/staterestructurlist.cfm (information on restructuring legislation and current situation for individual states);
Kenneth Rose and Venkata Bujimalla. 2002 Performance Review of Electric Power Markets, Review Conducted for the Virginia State Corporation Commission. August 30, 2002. Appendix B: State-by-State Summary of Rate Freeze Expirations and Rate Reductions. P. 96-103.

Note:
The table contains only utilities for which rate freezes have already expired.
*** Incomplete information on rate increases (includes only increases information on which is available)*
NA=Not Available

(2) STRANDED COSTS

Stranded costs refer to sunk costs and other committed expenditures that the utilities were unlikely to recover in a competitive generation market. Most of these costs arose from three sources:

•The difference between market value and book value of generation plant in a competitive environment,

•The excess costs of long-term contracts to purchase cogenerated power mandated by PURPA, and

•The costs of non-completion and eventual decommissioning of nuclear plants.

As noted, rate freezes in many states were accompanied by provisions for recovery of stranded costs. The recovery process typically involved three steps. First, the utility and the state regulatory commission had to agree on the amount of such stranded costs.[10] Second, funds in that amount were transferred to the utility and the costs "securitized" or paid for by the state with bonds of eight to 15 years duration.[11] Third, the annual costs of the bonds were treated as a business expense of utility operation, so ratepayers would pay them off fully over that time horizon.

One method of raising the necessary revenues for bond payment was supposed to be the difference between the frozen rates and expected declining unit per kilowatt-hour costs of the utilities under deregulation. This difference–the so-called competitive transition charge (CTC)-would be collected from ratepayers and accumulate during the freeze period, compensate utilities for their stranded costs, and then expire. At that point, rates were expected to fall to a level reflecting underlying costs of operation since the CTC would no longer be incorporated into the rate level.

The implication of this scenario is that when the CTC was in effect, actual rates were higher than equilibrium, since they included an administratively set surcharge having nothing to do with utility operating costs. Comparisons of pre-reform and such post-reform prices are therefore invalid because as they fail to recognize that observed post-reform prices are overstatements of equilibrium prices and hence that comparison with pre-reform prices understate the difference. Nonetheless, most of the studies evaluated here fail to correct for the distorting effects of stranded cost recovery charges. Exceptions are the Fagan and CAEM studies, which attempt not-entirely-successful adjustments. It should also be noted that the Joskow, Synapse, and GED studies at least acknowledge this issue.

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[10] Both the principles and the amounts of stranded cost recovery were heavily debated. For discussion, see Paul Joskow, "Deregulation and Regulatory Reform in the U.S. Electric Power Sector" in *Deregulation of Network Industries*, edited by Sam Peltzman and Clifford Winston, Virginia: R.R. Donnelly and Sons, p. 132.

[11] For a discussion of securitization and related matter concerning stranded costs, see *Alternating Currents: Electricity Markets and Public Policy*, by T. Brennan, K. Palmer, and S. Marinez, Brookings, 2002.

(3) EXCESS CAPACITY

The period from 2000 to 2004 has been characterized as one of substantial excess generating capacity in many regions of the country. FERC's *State of the Markets Report* for 2005 noted that more generation capacity was built during that time than in any other five-year period in history–indeed, nearly as much as in the previous 20 years.[12] While loads increased somewhat, this capacity growth put pressure on operations, suppliers, and prices. Many combined-cycle plants have run considerably less than anticipated, often as intermediate rather than baseload. In addition, they have tended to compete with each other rather than with less efficient older plants. Moreover, much of the additional plant has been built in the Southeast, PJM, and Southwest, regions already with surplus capacity.

The consequences have been rising capacity margins (that is, generator capacity in excess of peak utilization), abnormally low prices, and generator bankruptcies. Relative to normal capacity margins of 15-18 percent, nine of the 10 regions in the North American Electric Reliability Council (NERC) experienced excess summer reserve margins in 2004, in some cases twice the normal levels.[13] As FERC noted, this put "downward pressure on both energy and capacity prices in the market, and reducing net revenues for gas-fired capacity in most regions."[14]

The implications of excess capacity for a study of the price effects of restructuring are straightforward: To the extent that post-reform prices were depressed by the overhang of excess capacity, those prices do not represent a reliable basis for assessing the effects of reforms themselves. Rather, they embody a temporary mismatch of supply and demand that has the effect of lowering post-reform price below its equilibrium value and thus overstating the long-run effects of reform itself. While a few of the surveyed studies acknowledge the existence of excess capacity, only one--that by CERA--makes an explicit effort to adjust post-reform price for market disequilibrium, although that study's procedure is neither described nor seemingly effective. To that extent, most of these studies overstate the effects of reform itself.

D. Pitfall #3: Causation

The third methodological issue concerns the determination of causation, that is, whether or not reforms are actually responsible for some observed and properly measured change in price or cost. This is, of course, the ultimate purpose of studies evaluating electricity reforms, but a convincing demonstration of causation requires attention to several issues, not all of which are correctly addressed in these studies. These issues are: controlling for other factors, projection and prediction, and selection bias and endogeneity. We discuss each in turn.

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[12] FERC State of the Markets Report 2005, pp. 28-30, 59.

[13] FERC, ibid, Table 6.

[14] FERC, ibid, p. 29.

(1) CONTROLS FOR OTHER FACTORS

As noted in Joskow and Rose, economics rarely employs controlled experiments. Rather, relationships of interest must be isolated from real world data that are affected by a range of other factors. Controlling for those other influences is essential to actual determination of causation. Otherwise, in the phraseology of economics, correlation may be misinterpreted as causation. In the present case this raises a concern that restructuring may be judged responsible for some outcome whereas other factors are ultimately responsible. To establish causation correctly, one must control for those other factors must in some fashion be controlled for. There are several standard techniques for doing so depending on the underlying approach of a study as well as on the availability of data.

Clearly, the ideal technique would be to identify and measure all other relevant factors and to include them in some regression model. Regression analysis is well designed for this purpose, namely, to isolate the incremental effect of individual causal factors on some outcome variable. Thus, one might run a regression of prices in different states on a variable for whether or not each state has restructured its electricity industry, plus variables for other possible influences on state electricity price. The latter might include local differences in generation type, or climate, or fuel costs. In principle, the resulting cross-sectional data might disclose the separate effect of restructuring.

The problem is that not all possible causal factors can be identified, or at least one cannot be sure to have done so. Moreover, any conceptual variable may or may not be measurable, or may have alternative measures with different characteristics. The result is that the model still may not have controlled sufficiently for other relevant factors.[15] Two common approaches to this problem are as follows:[16]

•Panel data–by which is meant cross section and time series data together–can be used. The addition of time series means any unmeasured or immeasurable factors that affect each particular observation (say, a state) can easily be controlled for by using "fixed effects" terms on those observations. The fixed effects terms hold constant those factors that are specific to the state and that do not change over time, allowing the regression to focus on those factors–like restructuring–that vary across states or over time.

•The so-called difference-in-differences approach entails a comparison, say, of the price difference before and after restructuring in those states that did restructure, with the price difference over the same period in states that did not. Any unmeasured influences on all states' prices during this period (e.g., general fuel price increases) would be captured in the price difference in non-restructured states. By subtracting that difference from the price difference in states that restructured (but also experienced the fuel price change) one can in principle isolate

[15] Other factors that are not relevant generally do not need to be included, although this simply raises a question about the determination of what is relevant.

[16] For discussion of these approaches, see, for example, *Microeconometrics: Methods and Applications*, A. Colin Cameron and Pravin Trivedi, Cambridge, 2005.

the effect of restructuring.

Variations on these methods are possible. For example, one might use only time series data rather than full panel data, or one might identify a comparison group rather than all non-restructured states. These are inferior to the more general approaches just mentioned, but may be better than uncontrolled comparisons. Of course, poorly chosen comparison groups, for example, a small number of non-restructuring states with unusual characteristics themselves, are unreliable guides to the effects of policy.

The studies evaluated in this report vary in the adequacy of their controls. Some, like those by Joskow and Taber et al, have a lengthy list of control variables in their econometric models, whereas Fagan appears to have only one. Three of the econometric studies used panel data, the exception being Fagan, and with the proviso that Taber et al do not explain how their sample is drawn. In certain comparative studies, such as that by CAEM, control groups are chosen with little or no explanation. Some of these techniques seem not to exercise adequate care.

(2) PROJECTION AND PREDICTION

Studies that employ an econometric model of price or construct a counterfactual price assess the impact of restructuring in two fundamentally different ways. This is best understood by example: Suppose that while not all states restructured, restructuring occurred at the same time where it occurred at all. Suppose further that 20 years of data on state electricity prices are available, the first 12 years before restructuring and eight after. And finally, suppose it is generally understood that fuel price changes and some other factor or factors also affect electricity prices. The best statistical method for determining any effect of deregulation would be to estimate a regression model on all 20 years of data, with fuel costs, the other factors, and a dummy variable for restructuring[17] as the explanatory variables. The coefficient on the restructuring variable will in principle isolate any effect of policy, taking into account the effects of fuel costs and other factors on price. The magnitude of this coefficient is a measure of the incremental effect of restructuring on price, the standard error reports how precisely that coefficient is estimated, and the R^2 of the regression equation indicates how well the overall model explains the data.

An alternative approach is to estimate the same model of price on fuel costs and the other factor, but limited to the 12 pre-restructuring years. The resulting estimates are taken to be the correct underlying relationship between price and non-policy factors and used to predict prices in the post-restructuring period based on actual fuel costs and the other factors during those last eight years. That is, the coefficient on fuel price estimated from the pre-restructuring period is multiplied by actual fuel price in later years to project later electricity prices, and similarly for the other factors. The validity of this approach depends on the assumption that the same forces, other than policy, would otherwise have determined electricity price in the same way in the post-restructuring period. There are two reasons why this approach is inferior to the first approach

[17] A dummy variable is a variable that takes on a value of one for the years (and states) with restructuring, and is zero for all other years and for nonrestructuring states.

based on the full sample of data.

First, using the entire sample gives more data points on which to estimate the effect of fuel costs and the other factors. More observations–in the above case, 20 years instead of 12-better establish the impact of any control variables, yield more precise estimates for the variables of interest, and thus strengthen the predictive power of the regression model.

Second, failure to use the entire period may generate errors in the predicted effects of restructuring. This is most likely when the relationship between price and the non-policy variables differs in the post-restructuring period from their relationship in the pre-restructuring period. For example, fuel costs in particular may reach levels never before encountered, levels that may prompt conservation measures or changes in generation technology. These latter measures may alter the relationship between fuel costs and price compared to that in the pre-restructuring period, so that the previously estimated relationship will incorrectly predict post-restructuring price. Predicting outside the range of past experience–so-called "out-of-sample" prediction–will introduce errors insofar as it fails to capture changes in the relationship in the later period.

This possibility is illustrated in Figure 2. The dots represent the path of actual prices over time, adjusted for fuel costs. Out-of-sample prediction takes the relationship before the point of restructuring–time t–and projects it forward to time t+1, t+2, etc. This prediction is shown by the dashed line extending past time t, whereas actual post-restructuring prices are illustrated by dots corresponding to years t+1, t+2, etc. The latter may be lower to the extent that the predicted relationship is altered by some factor not experienced in the pre-restructuring period. And of course, precisely this occurred, as fuel prices increased around the time of restructuring, raising the risk of incorrectly attributing certain effects to restructuring.

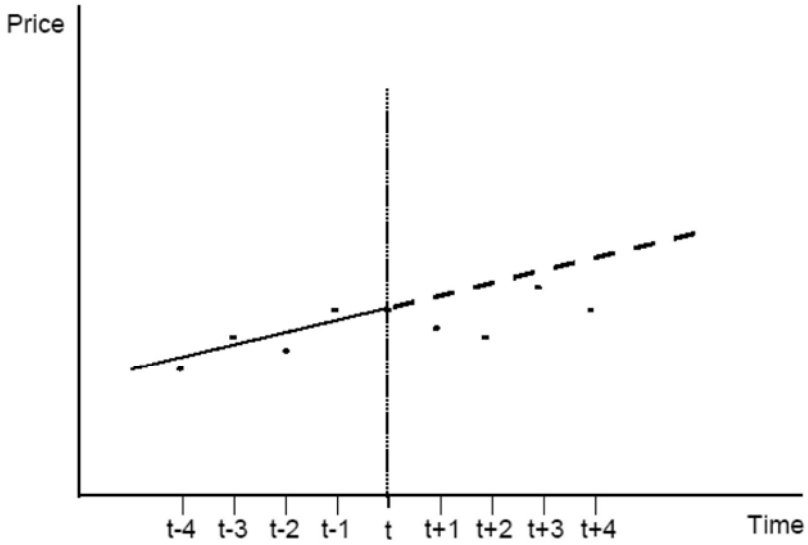
For these reasons, econometric techniques and counterfactual price calculations based on full samples (so-called "within sample" prediction) are preferred to out-of-sample estimates. Among the econometric studies reviewed here, Joskow and Taber et al utilize within sample techniques, for example, whereas CERA and Fagan do not.

3. SELECTION BIAS AND ENDOGENEITY

Econometric models or even simple comparisons of prices in restructuring versus non-restructuring states can encounter another more subtle methodological problem of causation. In principle in such models, the fact that some states have restructured is interpreted as the cause of any observed price difference between them and non-restructuring states, after controlling for all other relevant factors. But it is also possible that restructuring occurred in those particular states precisely because of the prices that existed there prior to restructuring, or because of some common force that simultaneously caused high prices and an inclination to restructure. To that extent the restructuring states may not be a random sample of all states, as econometric modeling requires. In that case, the result may be a biased estimate of the price effect of restructuring since

Figure 2

Illustration of Possible Error from Out-of-Sample Prediction



Data points are indicated for each year. Illustrative regression model on periods up until time t is shown by solid line, with dashed line representing predictions for years after the data sample. If the underlying relationship changes after time t, the out-of-sample prediction can diverge from the actual data points.

the estimate derives from a select set of states. The result is called "sample selection bias," simply "selection bias," or "endogeneity."[18]

In concrete terms, suppose that restructuring states are those that previously had unusually high prices. Restructuring may therefore have occurred in those very states since policymakers there were especially eager to try restructuring as a method for reducing prices. But in that case it is the fact of high prices in the first place that makes the state a restructuring state, and hence the measured effect of restructuring on prices after restructuring does not have the usual interpretation. The estimate at best might measure the effect of restructuring for high-price states. At worst, it may be entirely suspect if some characteristic of those states' political, social, or economic make-up simultaneously causes both the high prices and its effort to restructure.

Not all models assessing policy effects necessarily encounter selection bias. Rather, there must be a true and significant causal connection between some characteristic of the selected group and the policy variable. There are statistical tests for selection bias and endogeneity as well as corrections for them, and while the latter may be complicated, good methodology requires recognition of and attention to the issue. Implicitly assuming that restructuring "just happens" in some places, by contrast, may produce estimated effects that are either larger or smaller than the true effect. Among the studies reviewed here, Joskow acknowledges the issue, for example, and Fagan attempts to correct for it although not necessarily successfully. Other studies fail to address it at all.

E. Concluding Observations on Methodology

The studies reviewed in this report illustrate the wide variety of standard methodological approaches to evaluating regulatory reforms. Unfortunately, they also illustrate a number of pitfalls in such methodologies. Three of the more common ones discussed here are the failure to be precise about the reforms being evaluated, the use of a post-reform comparison price that is itself distorted, and an inadequate specification of causation. Each of these pitfalls by itself casts doubt on the conclusions of the study. In the next chapters, we shall examine additional specific problems that arise in each of the studies.

[18] The term endogeneity reflects the fact that the probability of being in the sample is related to a variable of interest, in this case price itself. To be clear, the problem is not simply that the restructuring states have some different characteristic. That would constitute an "omitted variables" issue, but not necessarily bias the coefficient on the policy action. Selection bias arises from the fact that "the unmeasured variable affects both the dependent variable and the probability of being in the sample." Peter Kennedy, *A Guide to Econometrics*, 2003, p. 286.

III. FOUR ECONOMETRIC STUDIES OF PRICE

Four of the 12 studies reviewed in this report offer quantitative assessments of the effects of restructuring that derive from econometric models of retail electricity prices. The models are used to examine whether prices differ between states or utilities that restructured vs. those that did not, or whether prices after restructuring differed from those that would otherwise have obtained. The first type of study is cross-sectional, the second time series. Most studies combine both types into panel data sets in order to strengthen the statistical basis for their conclusions. We discuss these studies in order of their publication, summarizing and evaluating each.

A. "Beyond the Crossroads: The Future Direction of Power Industry Restructuring," Cambridge Energy Research Associates, 2005 (CERA Study)

(1) SUMMARY

The 2005 Cambridge Economic Research Associates report has five major parts. The first and most important is its effort to measure the effects of electricity deregulation on the trend of power prices. Subsequent parts give letter grades for implementation of restructuring, discuss issues involved in a more robust transmission grid, propose administrative and other mechanisms for resource adequacy, and stress the need to "stabilize" the mixed regulatory/competition framework of the current industry.

These last four parts of the CERA study are mostly descriptive and are not the focus of attention here. Rather, we examine the analysis underlying the conclusion of the first part of the CERA report, namely, that as a result of deregulation, "U.S. residential electric customers paid about $34 billion less for the electricity they consumed over the past seven years than they would have if traditional regulation had continued."[19] In support of this, the report offers a threefold argument.

First, CERA examines real power price trends for the entire United States for 1978-2004 and observes that "the average US real price of power is currently lower than at any point in the past two decades."[20] In order to isolate the effects of reform, CERA proposes a definition of deregulation as "a period when the electric power industry moved from a structure dominated by regulation and public ownership to one incorporating significant market mechanisms."[21] Operationally, CERA simply chooses the year 1997 as an "inflection point" for restructuring. In support of this cutoff, the report simply notes a series of policies that were approved or took

[19] CERA Study, pp. ES-1, I-1.

[20] CERA Study, p I-1.

[21] CERA Study, p. I-3. The reason for mention of public ownership is unclear since there has been no major shift in ownership status of industry assets and operations in recent years.

effect in the 1996-1999 period.[22]

Secondly, the report proposes reasons for what the authors claim is the erroneous conventional wisdom about deregulation, namely, that it has not lowered prices for consumers. It asserts, without further explanation, that the incorrect impression is due to "money illusion"--the failure to adjust for inflation--and to "vividness bias," which it describes as the tendency to weigh that which is apparent more heavily than what is subtle but often more accurate.

In its third argument, the report claims that using lower prices to evaluate deregulation is a "flawed criterion poorly applied."[23] Rather, it asserts, the appropriate criterion is whether or not power prices fluctuate in a manner that provides appropriate signals for economic efficiency. It further notes that prices should mirror trends in marginal costs, with fuel costs the largest component of variable costs in electricity production.

Following this argument, the CERA report then sets out its procedure for determining the effects of deregulation. It estimates what the price would have been with continued regulation for the period 1998-2004 and compares it to the actual "deregulated" price during that period. To estimate the price with continued regulation, CERA first uses the following econometric model to establish the relationship between two cost factors and electricity price under regulation:

$$Price_{RY} = B_0 + B_1 \bullet FuelPrice_{RY} + B_2 \bullet RateBase_{RY} + \varepsilon \qquad (1)$$

with variables defined as follows:

Price = Consumer Price Index (CPI) for electricity price, by region,
FuelPrice = average delivered cost of fuel for power generation, adjusted by the CPI
RateBase = an index of the real return on capital

The term ε is the appropriately included error term, while B_1 and B_2 estimate the effects of fuel and rate base costs, respectively.

This equation is estimated using data for four regions *R*–Northeast, West, South, and Midwest--and all years *Y* from 1981 to 1997. The results of a pooled cross-sectional regression gives positive and statistically significant coefficient estimates for B_1 and B_2, indicating (not surprisingly) that price is higher where fuel costs and financing costs are greater. The overall explanatory power of the regression is given by its R^2 of 0.64.

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[22] There is no actual inflection point in any data series. The CERA report creates a fictitious line drawing with such a point from its characterization of policy actions taken during this time. Those actions were a combination of wholesale market changes contained in Order 888 that FERC issued in 1996, legislation for deregulation signed by the governor of California in 1996, and the commencement of operation by the first ISO in Texas in 1996, the PJM ISO in 1997, and the New England ISO in 1999.

[23] CERA Study, p. I-7.

CERA then uses this model to project rates for the years 1998-2004, as if regulation had continued, based on actual fuel costs and financing costs during those forward years. Comparing these predicted regulated rates to actual rates and aggregating over all output, CERA concludes that cumulative U.S. net gains from deregulation are $34 billion during the 1998-2004 period. While some losses were incurred due to deregulation in the West, these are said to be more than offset by gains in the other regions of the country, especially in the South. Indeed, the study claims that, with exception of the West, the greater the level and duration of deregulation–as measured by its index of deregulation--the greater the savings on a per megawatt-hour basis.

Notably, this study first states that "[t]he savings from power deregulation are net savings--including...the unintended consequences of price freezes, the California power crisis, and power development investor losses."[24] But then it proceeds with an effort at adjustment for the effect of excess capacity. Its method for doing so is to estimate the regulated price "using only the amount of capacity additions needed to keep regional supply and demand in balance."[25] The CERA report claims that the net effect of this adjustment was negligible, and therefore the study's results still stand. The study also includes a discussion of a number of other matters, the most relevant of which is its argument that deregulation has shifted risk in the power business from consumers to producers, with further benefits to consumers.

(2) COMMENTARY

The CERA study uses one of the basic methodologies outlined in Chapter III, namely, an econometric model of price that allows for controlled comparison of regulated vs. unregulated prices over time. For this approach to yield sound results, the mechanism for predicting counterfactual price (that is, what the regulated price would have been in the unregulated years) must be sound. In this regard, despite one or two strengths, the CERA study generally falls short. Here we list and discuss its major limitations.[26]

(1) Perhaps most basically, the study's use of 1997 as the year of "demarcation" between regulation and restructuring is too simplistic. As discussed in Chapter II, restructuring has been a multidimensional process, taking place in stages over time, and at altogether different times in different places. There is no single point in time for deregulation, and indeed the events cited in the CERA study hardly support its conclusion to use the year 1997 as that time.[27]

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[24] CERA Study, p. ES-1.

[25] CERA Study, p. I-16.

[26] This discussion draws on some points made in "Beyond Belief: A Critique of the Cambridge Energy Research Associates' Special Report," Christensen Associates, November 2005, and in "A Response to Two Recent Studies That Purport to Calculate Electricity Restructuring Benefits Captured by Consumers," Howard Spinner, November 2005.

[27] While it is true statistically that crude categorizations can sometimes pick up phased changes, such categorization introduces errors, can bias coefficients, and runs the risk of spurious results.

(2) The model explaining price is extremely rudimentary, relying as it does on only two explanatory variables–fuel price and rate base cost. No doubt these are important, but the absence of other factors such as generation type and demand conditions is notable. In addition, given the panel data set employed, fixed effects for regions and years should be included to control for other influences. The failure to include these latter variables at least for regions assumes identical price paths for all regions, an assumption that is almost certainly incorrect and responsible for inaccurate price predictions by region.

(3) The study uses a model estimated for 1990-97 to predict 1998-2004 prices. Such "out-of-sample" prediction is statistically inferior to estimating a model on the entire period and then testing for differences in the period of deregulation. As discussed in Chapter II of this review, this latter approach includes more observations, gives more accurate estimates of the effects of some causal variables, and protects against the possibility that the effects of some variables differ between the two periods. The likelihood of this final problem seems clear from the unprecedented increase in natural gas costs starting in 2000. Moreover, whatever the merits or limitations of its prediction method, the CERA study fails to provide confidence intervals or other measures of the statistical reliability of its estimates of cost savings by regions and years.
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(4) The CERA model predicts poorly and in some cases nonsensically. The graphs of actual and predicted prices by regions–Figures I-12 to I-15--indicate clear weaknesses of the model in predicting prices even in the regulation period. More telling yet is the fact that for all four regions the predicted price exceeds actual price in the year 1997, and for three regions, for 1996 and yet earlier years. This suggests that some factor omitted from the model started to overestimate prices beginning in the mid to late 1990s--*before* restructuring got under way. This should serve as a caution about the reliability of the model's post-1997 predictions, which show similar differences. Further indication of the weakness of the model is provided in the Christensen Associates' critique of the study, which estimates a yet-simpler model than CERA's, but one that performs better in the regulated period.[28] In contrast to CERA's model, Christensen's shows no statistically significant break in prices in 1997 whatsoever.

(5) Further indication of the model's unreliability is its results by region. The study concludes that the South has the largest savings, fully $24 billion of the total net benefit of $34 billion. But this is inconsistent with the fact that of all regions the South has experienced the least restructuring. State efforts at divestiture and competitive wholesale markets have been stymied. No RTOs have been formed. Retail competition is virtually non-existent. Yet the model projects price under continued regulation far higher than actual price, giving rise to this oddity of a huge benefit from restructuring in a region where it largely did not happen.[29]

(6) CERA acknowledges both rate freezes and excess capacity as issues, but its effort to

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[28]Christensen Associates, November 2005, pp. 9-11. Christensen graciously provided the data underlying their regression, permitting replication of their results.

[29] This may be because utilities in the South were less vulnerable to the rapid fuel price increases starting in 2000.

interpret those as benefits of restructuring is incorrect. As discussed in Chapter II, rate reductions and freezes administratively lowered post-1997 prices, and so these savings are more accurately attributed to regulation than to reform. Later, the report asserts that "a significant portion of the gains are due to power customers' not shouldering the cost of much capacity added in the post-1997 period."[30] But treating investor losses on new and excess generation as a benefit of restructuring is an effort to credit reform for what is a one-time, disequilibrium event. Clearly, in the long run, investors will insist on proper compensation for risk, compensation that will be reflected in rates that consumers must pay. CERA's interpretation presents a misleading, if not outright erroneous, impression.

In summary, the CERA study is deficient in its economic foundations and in its estimation procedures. Accordingly, its results cannot be relied upon to judge the effects of electricity restructuring.

B. "Markets for Power in the United States: An Interim Assessment," Paul Joskow, 2006 (Joskow Study)

(1) SUMMARY

In the last section of a lengthy article on electricity deregulation, Joskow offers an analysis of retail prices after reform. He first notes the difficulties of determining the counterfactual price and then proceeds with three approaches to the problem: an analysis of time series data on prices, a comparison of price trends in states with and without retail competition, and finally, a regression analysis.

From a long time series of average real residential and industrial prices for the United States as a whole, Joskow observes that both residential and industrial prices fell continuously from the early 20th century to about 1972. Thereafter, real prices started increasing as a result of rising fuel costs, growing nominal interest rates, exhaustion of scale economies in generation, and oil supply shocks. Real prices reached their peak in the early 1980s and then began to fall, reflecting lower fuel prices and interest rates. Despite the fact that this occurred just after PURPA first took effect, Joskow rejects any causal association with that policy initiative.

Joskow next compares trends in retail prices in states that adopted retail competition with the trends in states that largely continued the regulated monopoly system for electric utilities. Indeed, data from the period 1996-2004 suggest that prices behaved differently. Real residential prices fell more in states that implemented retail choice programs than in those that did not. While the average price reduction among states without retail competition for this period of time was around 8%, price reduction in states with retail competition varied from 11% to 32%. The only exception was Texas which showed an increase in retail prices (3%). Rather oddly, however, the reduction in retail prices was much higher in those states that had almost no residential switching from the incumbent utility to competitive suppliers.

As for industrial prices, Joskow calculates the average reduction for states without

[30] CERA Study, p. I-15.

competition to be about 24%. Among the states with retail choice programs, only Maine and Illinois showed price reductions greater than those without retail choice, whereas eight states had smaller reductions. In these results, California showed almost no change–a curious finding, given that state's problems during those years--while Texas and Nevada had very large actual increases in prices.

In the final step of his analysis, Joskow offers a "first, admittedly crude empirical analysis"[31] of the effect of deregulation on retail residential and industrial prices. He estimates an equation explaining average residential or industrial price by state for the period 1970-2003, labeled *Price*, as a function of variables measuring a combination of cost drivers and policy initiatives. The equation is as follows:

$$Price_{it} = \beta_0 + \beta_1 RFC_{it} + \beta_2 Hydro_{it} + \beta_3 Nuclear_{it} + \beta_4 RYield_t + \beta_5 Size_{it} + \beta_6 PURPA_{it} + \beta_7 EWG_{it} + \beta_8 Retail_{it} + \mu_i + \nu_t + \varepsilon_{it} \quad (2)$$

In this expression, i designates states and t indexes years. The cost variables are as follows:

RFC = average real fossil fuel price per kWh of total electricity supplied,
RYield = real yield on electric utility debt,
Hydro = share of total electricity supplied coming from hydroelectric generation,
Nuclear = share of total electricity generation coming from nuclear plants, and
Size = average annual electricity consumption.

The policy variables are:

PURPA = the share of total electricity generation coming from cogeneration and related sources sanctioned by PURPA, beginning in 1985
EWG = the share of electricity coming from unregulated "exempt wholesale generators" beginning in 1998, and
Retail = a dummy variable indicating whether or not a state had introduced retail competition in a particular year, beginning with 1998.

The last three terms in equation (2) represent state-specific error, time-specific error, and random error, as is standard with time series, cross section data. In this specification, *EWG* is intended to measure the effect of wholesale competition while the variable labeled *Retail* is intended to capture the effect of retail competition. This regression model is run separately for residential rates and industrial rates. Joskow also runs both models for the shorter period 1981-2003 during which rates seemed to resume their long-term decline.

In all four models the cost drivers behave as would be expected. More to the point are results on the policy variables. Joskow reports that for the longer time series, PURPA generation is associated with the higher retail prices, corroborating his prior view that the net effect of PURPA was to lock utilities into excessively costly power. On the other hand, the results confirm that the greater the share of electric sales from exempt wholesale generators (*EWG*), the lower the retail prices. Finally, the coefficient on *Retail* is consistently negative. That implies

[31] Joskow Study, p. 28.

that states implementing retail competition have had lower retail prices, everything else held constant.

Estimates for the time period 1981-2003 are obtained as well, the main difference being somewhat lesser statistical significance to most variables in the recent period. Overall, Joskow concludes that both wholesale and retail competition lead to lower retail prices–perhaps 5 to 10 percent lower on average, holding cost factors constant. These results are similar for both residential and industrial prices in both time periods. Overall, this study finds significant benefits to restructuring.

(2) COMMENTARY

Joskow's study is one of the more careful quantitative assessments of electricity restructuring. He uses the full sample in order to maximize reliability of coefficient estimates. He incorporates a number of control factors, which indeed prove significant. He has controls for both state-specific and time-specific errors. And he forthrightly acknowledges that his effort is just a "starting point," even offering his own caveats. Those caveats are as follows:

First, Joskow notes that data on customers served by competitive retailers are very difficult to obtain. Excluding those customers, as he has done, may result in an overestimate of some price data. On the other hand, average prices may be underestimated insofar as the available cost data include only delivery charges for customers who switched from default service. Secondly, some right hand side variables (*Retail*, for example) are endogenous, which likely leads to an underestimated effect of retail competition. Joskow notes that the use of a long data series and state-specific fixed effects may help in avoiding this bias. Finally, Joskow states that the effect of retail competition on consumers is not consistently positive in all states that introduced these reforms and for all customers, although he asserts that in the long run the benefits "can significantly outweigh the costs."[32]

Apart from these qualifications, additional questions can be raised about this analysis:

(1) Joskow appears not to have made any correction for price reductions and freezes in the deregulation period. There is no mention of these problems with his price series, but as previously discussed, failure to correct for these distortions will result in an overestimate of the effects of restructuring on price from the regression results. An analogous concern arises with respect to the impact of excess capacity, which also appears to have temporarily held price down, and stranded cost recovery, which works in the opposite direction. The absence of correction for these factors results in a comparison of regulated price to distorted deregulated price, rendering the results suspect.

(2) The variable *Retail* is a simple "zero-one dummy variable," meaning that it is assigned a value of zero in the absence of restructuring or a value of one where restructuring it deemed to have occurred. No other values are used. But electricity retail restructuring is in reality a continuous process of increasing competition in state retail power markets. The text of

[32]Joskow Study, p. 32.

the article states that it is equal to one in the year in which the state introduced retail competition, though the Appendix offers a somewhat different explanation, namely, that the variable represents the "[a]uthor's assessments based on programs initiated in each state."[33] But simply allowing customers to choose another electricity supplier does not mean that there is competition. It is unclear, for example, how Joskow determines this variable in states where independent retail suppliers are numerous because state retail prices are high, versus other states that have legally allowed retail competition but where prices are set too low for entry to be viable.

(3) Finally, there appears to be an important inconsistency in data used in the analysis. The published paper states that *Price* is "average retail residential or industrial price," making no mention of inflation correction. By contrast, *RFC* is stated as "average *real* fossil fuel price"[34] (emphasis added). Ordinarily for data extending such a long time and displaying such substantial changes, inflation correction would be standard practice. Alternatively, regressing nominal price on nominal fuel costs might be done, although needlessly harder to interpret. But it would be poor statistical practice to regress nominal electricity price on real fuel costs, or vice versa. Such a mixing of data creates the very distinct possibility of biased, even outright erroneous, results.[35] Yet a close reading of the text and data appendix to this paper suggests that that is precisely what was done.[36]

In summary, Joskow's study in many ways represents a good effort at evaluating the price impacts of electricity restructuring–in many ways, but not all. Its limitations are sufficiently serious that its results should not be relied upon as a guide to the effects of restructuring.

C. "Examining the Effects of Deregulation on Retail Electricity Prices," John Taber, Duane Chapman, and Tim Mount, 2006 (Taber et al Study)

(1) SUMMARY

The working paper by Taber, Chapman, and Mount begins by noting that the purpose of electricity deregulation was to reduce the retail price of electricity. It proceeds to summarize several studies of the effects of deregulation, to examine some preliminary data, and then to undertake a new study.

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[33] Joskow Study, p. 32.

[34] Joskow Study, p. 29.

[35] Simulations of a regression model on mixed real and nominal data indicate the distinct possibility of biased results, including quite possibly finding price effects that do not exist. Thanks to Maria Luengo-Prado for assistance with this issue.

[36] In an effort to clarify this issue, this author asked Joskow, who responded that he believed he had run the model both in fully nominal and in fully real terms and would check further (email communication, August 3, 2006). No additional clarification was received, however, and so this review reads the paper literally.

The study's preliminary examination of retail price data looks at different consumer types, different types of utilities, and different ISOs in the period 1990 to 2003. Inspection of graphs indicates that nominal industrial prices rose most for deregulated utilities, while commercial and residential customers saw much smaller increases. The difference between deregulated and regulated prices grew throughout this period, although most of the gap is due to the experience in California. Taber et al conclude that "deregulation may not have succeeded in its aim of lower prices through the efficiencies generated by competition."[37] But since other factors may be important, they emphasize the need to do a more thorough analysis.

Their empirical study compares prices for utilities in deregulated states with prices in regulated states between 1990 and 2003. This study defines deregulation in the context of wholesale markets. Although the authors note four major components of deregulation–the formation of ISOs, the creation of auction-based wholesale markets, retail choice, and divestiture of generation–their definition is based on the first two factors. According to what they call their "primary definition," a utility is deregulated if it belonged to an ISO with an auction-based market in the year 2002. Their second definition designates a utility as deregulated "only for those years in which it actually belonged to an ISO." For the third definition, a utility is considered deregulated "only for the years it belonged to an ISO which had an auction-based market."[38]

Prices are examined for each of four consumer classes (residential, commercial, industrial consumers, plus the average overall prices) and also for three categories of utilities--privately owned in regulated states, privately owned in deregulated states, and publicly-owned. Prices are examined both in nominal and in real terms. With all possible combinations of consumer classes, nominal/real prices, and definitions of deregulation, there are 24 different possible model specifications.

Taber et al suggest a number of factors that can independently affect prices of electricity and must therefore be controlled for. These variables fall into the following categories:

•Fuel cost per unit of output,

•Climate, measured by heating and cooling degree days, and

•Type of generation, represented by the amount of power generated from coal, oil, natural gas, nuclear, hydro, or other renewable sources.

[37] Taber et al Study, p. 15.

[38] Somewhat different second and third definitions are given later in the study.

The policy variable in this study is simply whether or not a utility belongs to an ISO with an auction-based wholesale market for one or more of the years in the period. ISOs with this property are the California ISO, PJM, the Electric Reliability Council of Texas (ERCOT), the New England ISO, and the New York ISO. Regulated IOUs and publicly owned utilities are also included, with publicly owned systems the default category because their prices are said to be lowest. The authors appear to have approximately 85 utilities in their sample.[39] Most of the regressions are run with commendable corrections for certain statistical problems, known as heteroscedasticity and autocorrelation.

At this point the Taber et al study proliferates model specifications. In addition to having simply price as the dependent variable, another set of regressions uses "gap variables" as the dependent variable, where "gaps" are the percent difference between regulated and unregulated price, and between public and private utility prices. These models use a combination of "gap" and "non-gap" versions of the independent variables. Finally, in another variation, they rerun all price models with generation mix ratios instead of generation amounts, use-weighted fuel prices instead of a simple average fuel price, and dummy variables for NERC regions, together with the usual climate and ISO membership terms, as explanatory variables.

Each model is estimated on all 24 combinations of consumer classes, deregulation definitions, and nominal/real prices, resulting in more than a hundred different regressions. For presentation purposes, the authors provide two types of tables. The first table reports "Typical Regression Results" for each model and the second a "Meta-Summary of 24 Regressions." The "typical regressions" are for industrial prices (or their gaps), but it is not clear which definition of deregulation is employed. The Meta-Summary provides information on the simple average of coefficient estimates across all 24 models as well as the number of such coefficients (out of 24) that are statistically significant.

The "typical" regression results reported for the first category of model–on price itself--are said to be similar to most others. The overall explanatory power of the model is measured by an R^2 of 0.42 and many, but not all, control variables behave as expected. The coefficient for regulated IOUs is negative and significant, contrary to the expectation that publicly owned utilities would exhibit the lowest price. Of the five ISO dummy variables, all but that for ERCOT (or in one set of models, those for ERCOT and PJM) are positive and statistically significant. The Meta-Summary of 24 such regressions shows much the same thing.

With respect to regressions on "gap" variables, the results are statistically much weaker. Taber et al conclude that "price differences cannot be easily explained by any of these models."[40] As for their third model, based on alternative definitions of some variables and with

[39] While they do not disclose the number, there are 1,177 observations over 14 years, implying about 85 utilities. Attempts to confirm this in private communication with one of the authors were not successful.

[40] Taber et al Study, p. 27.

dummies for NERC regions, Taber et al report one set of results suggesting a negative price effect for PJM and a positive effect for the New England ISO, but the meta-analysis indicates that in general only the California ISO has a statistically significant effect, and that is a positive (i.e., price-increasing) one.

This mix of results is difficult to interpret and summarize, so Taber et al base their main conclusions on one final table that compiles all coefficients derived from all ISO variables, three definitions of deregulation; and eight regressions for each definition. From this meta-summary, they observe that for most ISOs the average coefficient values are both positive and larger than the coefficients for privately regulated utilities. Hence, the results "do not support a conclusion that in aggregate deregulation has lowered electricity rates relative to those rates in still-regulated states."[41] However, the authors concede that "only 39 out of 60 coefficients from which these averages are generated are significant at the 5% level".[42]

(2) COMMENTARY

The Taber et al study is notable for its multiplicity of model variants, but in that and other respects it is a study with more limitations than strengths. We note the following major concerns about its methodology:

(1) The basic definition of a deregulated utility--membership in an auction-based ISO in 2002--is flawed. This criterion ignores two of the components of restructuring noted at the outset of this study itself, namely, retail choice and divestiture. Moreover, this approach treats restructuring as a dichotomous event, although most aspects involved a process of phasing in. Apart from that, ISO membership in the year 2002 is inexplicably used to assign a utility[43] to deregulated status for the entirety of the 1990-2002 period. This introduces errors into the variables, since data for all years *prior* to actual entry into the ISO are treated as representing deregulated status. The second and third definitions of deregulation are limited to years in which a utility is a member of the ISO, which is clearly the more appropriate criterion, although that does not resolve the issue that simple ISO membership defines deregulation.

(2) The rationale for using "gap variables"–really, percent changes--is unclear. The economic factors responsible for different price levels are not the same as those responsible for changes, and indeed, it is unclear whether deregulation should alter the rate of change in prices as opposed simply to their level. This study does not seem to recognize these issues. Instead, it proceeds simply to run dozens of additional regressions on the alternative dependent variables. It may therefore not be surprising that the regressions on "gap variables" leads the authors to conclude, "Price differences cannot be easily explained by any of these models..."[44]

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[41] Taber et al Study, p. 29.

[42] Taber et al Study, p. 29.

[43] In places the text alludes to states rather than utilities as being deregulated, but the criterion of membership in an ISO applies only to utilities.

[44] Taber et. al, Study p. 27.

(3) In addition to deregulated utilities, the study incorporates prices of regulated IOUs, since they are the obvious comparison group. But it also includes publicly owned utilities, and then specifies the model so that they are the default group. It states that "[i]f deregulation has been effective in reducing retail electricity rates, the constant terms for ISO's should have a negative or zero coefficients." Given that publicly owned utilities are the default group, that approach is incorrect. A negative coefficient on an ISO term would simply indicate less expensive power from that ISO member relative to publicly owned systems. Whether the ISO's power is cheaper than that from a private regulated utility would require a statistical test of that difference to the difference between the ISO and the publicly owned utility. That test is not performed anywhere in this study.

(4) The "meta-summaries" offered in the study do not represent a valid basis for drawing conclusions. Indeed, since meta-summaries are nothing but arithmetic averages of the coefficients from dozens of regressions run in this study, the results would differ with different model specifications or numbers of regressions. But "results" that depend on a particular set of selected models are quite arbitrary. Moreover, arbitrary or not, there is no economic meaning or statistical test for the "average value" of a coefficient from a group of entirely separate regressions. Those models are not equivalent in any way, and so their average is without meaning. Similarly, counting the number of regressions (out of 24) with a statistically significant coefficient estimate lacks meaning, since this, too, is entirely dependent on the batch of regressions that happen to have been run.

(5) The Taber study uses price data throughout without recognizing that post-restructuring price reflects price reductions and freezes, stranded cost recovery charges, and excess capacity for many utilities. As a result, the price effects of "restructuring" that are estimated include the purely administrative phenomena of freezes and stranded costs, plus the input market phenomenon of excess capacity, all of which result in a distorted post-restructuring price. For this reason alone, the results are suspect.

In summary, the Taber, Chapman, and Mount study does not appear to be well designed or specified. It is statistically inconclusive and should not be relied upon to help understand the effects of restructuring.

D. "Measuring and Explaining Electricity Price Changes in Restructured States," Mark Fagan, 2006 (Fagan Study)

(1) SUMMARY

Fagan begins his study by noting that the "key impetus" for electricity restructuring was "the desire of industrial customers in high-priced states to reduce their electric bills." He then notes disagreement between studies regarding the actual effects of restructuring, thus motivating his own inquiry into industrial price differences between states that restructured and others that did not. The focus on industrial prices is justified by the argument that standard offer prices in most restructured states continue to be set by a mix of competitive and regulated forces, whereas

industrial prices tend to more closely reflect the competitive marketplace, both because of different regulatory approaches and because of higher rates of industrial switching to competitive suppliers.

Fagan develops a counterfactual model of price differences between restructuring and non-restructuring states over the period 2001-2003. Counterfactual prices–that is, those that would have arisen under continued regulation–are determined by first constructing a model that attempts to explain prices for the period 1990-97 using selected inputs, and then applying that model to predict prices based on values of the same inputs for 2001-03. The model used to estimate prices is:

$$Price_{it} = \alpha_i + \beta_i\, t + \theta_i\, FuelPrice_{it} + \varepsilon_{it} \qquad (3)$$

where *Price* = real industrial price paid in state *i* in year *t*
t = a time trend
FuelPrice = real price of natural gas in the region.
Again, ε_{it} denotes the error term.

Fagan explains that the parameters α, β, and θ are determined "for each state *i* using real (2003$) industrial electricity prices and real (2003$) average city gate price of natural gas for all years (1990-1997)."[45] This and other comments about "state regressions" together with graphical results by state (Fig. 3) would seem to imply that the equation was estimated once for each state; otherwise, there could be no state-specific values to the coefficients. The results of these regressions are not reported, nor is the estimation technique explained, but Fagan does state that the "vast majority of [high] explanatory power lies with the time variable" and that "the gas variable is rarely significant in the state models."[46] Using these regressions and data for 2001-03 on the explanatory variables, predicted prices as if regulation persisted are obtained for restructuring utilities. This predicted price series is then compared to actual prices in 2001-03.

While none of these state-specific prices are shown, Fagan reports that actual prices were lower than predicted prices in 12 of 18 restructured states. By contrast, the same was true for only seven of 25 non-restructured states. A mean difference test is said to yield a t-statistic of 2.07, just barely in the range of statistical significance.

Fagan then undertakes a separate comparison of average price differences between all restructuring and all non-restructuring states based on "consumption-weighted average prices" in 2001-03. He reports that the average actual prices were 7.5 percent higher than predicted prices in restructuring states, compared to 9.2 percent higher in non-restructuring states. Next, Fagan adjusts price data in restructuring states for stranded costs. His method involves use of data from the Edison Electric Institute and state public utility commissions to remove competitive transition charges from total price. The result is that actual prices in restructuring states net of

[45]Fagan Study, p. 36.

[46]Fagan Study, p. 38.

these stranded costs are found to be only 1.3 percent higher (rather than 7.5 percent higher) than predicted levels. The benchmark value for non-restructuring states–9.2 percent–remains unchanged.

Finally, the Fagan study then develops two additional models to further examine the determinants of the differential between actual prices and predicted prices. The first regresses the price difference from the previously predicted values on a variable for the restructuring status of the state, which simply tests for a correlation between the variables. Thus,

$$Diff_i = \beta_0 + \beta_1 Rest_i + \varepsilon_i \qquad (4)$$

where *Diff* = the difference between actual and predicted 2001-2003 price in each state i
Rest = a dummy variable for the state's restructuring status.[47]

The second model examines the change in price for each state between 1993-95 and 2001-03. For explanatory variables, it includes restructuring status but also the state's participation in a well-functioning RTO, the state's pre-restructuring (1993-1995) electricity price, the state's difference between the actual 1993-95 price and the counterfactual 1993-95 price, and the change in 2001-03 predicted price from 1993-95 predicted price (based on the counterfactual model). These are said to reflect such things as effective wholesale market design, as well as the state-specific impact of gas prices and various regulatory forces on electricity prices. The estimated equation is as follows:

$$\Delta \text{Price}_i = \beta_0 + \beta_1 Rest_i + \beta_2 \Delta PredPr_i + \beta_3 RTO_i + \beta_4 InitialDiff_i + \beta_5 InitialPr_i + \varepsilon_{ii} \qquad (5)$$

where *ΔPrice* = change in actual prices between 1993-95 and 2001-2003
Rest = dummy variable equaling one in restructuring states
ΔPredPr = change in predicted price between 1993-95 and that in 2001-2003
RTO_i = membership in a "well-functioning" RTO
$InitialDiff_i$ = difference between 1993-95 actual and predicted price, and
InitialPr = prerestructuring price (1993-95).

In addition, in both models the variable for restructuring *Rest* is said to be quite possibly endogenous and a correction is introduced. The correction factor–an "instrument" that is supposed to be highly correlated with *Rest* but not with the dependent variable[48]–is, in equation (4), membership in an RTO, while the instrument in equation (5) is George W. Bush's share of 2004 major party presidential votes. No explanation for the choice of these variables is offered.

In the bivariate regression (4), Fagan finds a negative but insignificant coefficient on the restructuring variable and concludes (in contrast to his results on the first question) that

[47] While this is not defined, it appears to be a dummy variable based on the year in which each state restructured.

[48] These issues are discussed in Peter Kennedy, *A Guide to Econometrics*, op. cit.

restructuring is not responsible for state price differentials. With respect to price changes, the sign on restructuring in fact is reversed and the effect of RTO membership is insignificant. The 1993-95 actual price *InitialPr* and the change in counterfactual prices between the periods *ΔPredPr* are statistically significant. Fagan concludes that "neither regulatory reform at the retail level (restructuring status), nor at the wholesale level (RTO participation) is a significant driver of the restructured states' superior price performance."[49]

(2) COMMENTARY

The Fagan study first estimates a counterfactual model for predicting prices under continued regulation, and then uses what it terms a two-stage model to deal with sample selection and endogeneity issues. Few details of either the procedures used or the results obtained are reported, however, and some of the descriptions are inadequate and unclear. We note the following specific limitations of this study:

(1) The counterfactual model is too simplistic to produce reliable predictions. Fagan's model has only two explanatory variables–gas price and a time trend. This already fails to control for many other causes of differences and changes in electricity prices. Moreover, he acknowledges that gas prices are generally insignificant explanatory variables. This implies that his "model" consists of nothing more than a linear time trend, hardly an adequate basis for analysis.

(2) Fagan's use of this model to project 2001-03 electricity prices is even more problematic, for several reasons. First, the crucial explanatory variable is already known to be statistically insignificant so that any estimates based on it are unreliable. Confidence intervals around his point estimates–which he does not provide–would confirm that they offer little or no guidance. Secondly, Fagan's approach represents out-of-sample prediction which, as discussed in Chapter II, is less reliable under the best of circumstances than a within-sample approach. The limitation of out-of-sample prediction is made clear by the statistical insignificance of gas price, which undoubtedly plays a role in 2001-03 prices that is not captured in the estimation period 1990-97. Thirdly, the gas cost variable that is used for prediction is said to be a regional price index, rather than state-specific prices. This implies that the model assumes that the predicted prices in all states in a region move in lockstep in the post-restructuring years. This is an inadequate assumption on many grounds, not the least of which is that the predicted prices for all such states represent a single observation, not one for each state. Fagan's t-statistic on the groups of states is therefore invalid.

(3) Fagan's benchmark models of industrial prices appear to have been estimated for each individual state, rather than for all states together. If so, the model would have two explanatory variables and only eight observations for each state. Eight observations are too few for a meaningful estimation of a regression model with reliable results. Those regressions therefore do not qualify as a well-specified and reliably established model.

(4) Fagan's second and third estimations–on the difference between actual and predicted

[49]Fagan Study, p. 41

prices, and between the regulated and deregulated periods –are problematic for several reasons. The regression of the price difference on a restructuring variable is in reality nothing more than a simple correlation between the two series. Fagan reports an insignificant negative effect of restructuring, but that is difficult to reconcile with his first empirical finding, which was that the price differences were smaller in deregulated states.

(5) Fagan's third estimation, in which he checks whether various factors might be causally related to price changes over time in regulated and deregulated states, raises further questions. In particular, if there were reason to believe these factors might be important, they arguably should have been included in the initial regression, which after all was intended to isolate causal factors. Moreover, Fagan introduces a number of quite doubtful independent variables in this regression. Three such variables–initial price, actual minus initial price, and the change in predicted price--are all by definition related to each other and to the dependent variable, making interpretation of any of the coefficients impossible. No motivation for these variables is offered in the study; indeed, for some it is difficult to imagine what that motivation might be.

(6) The crucial restructuring variable is defined only as a "state's restructuring status," but precisely what that means is not explained. Fagan observes that that variable is likely to be endogenous with price, due to the fact that restructuring occurred sooner in states with higher prices. Accordingly, he proceeds to instrument for it in the actual regressions.[50] In principle this is good procedure, though in practice it depends on the quality of the instrument. A good instrument will be correlated with the likely endogenous variable (in this case, *Rest*) but not with the error term. Fagan offers no explanation for his choice of instruments–"participation in a well-functioning RTO"[51] for his bivariate model, and "George W. Bush's share of 2004 major party presidential vote" for the augmented regression. He offers no explanation for the use of two different ones for the same right hand side variable. He does not report any statistical test for endogeneity, a standard practice when this is a potential concern.

In summary, Fagan's study does not represent good economic methodology or good econometric technique. Apart from its notable effort to deal with stranded costs, the study's data, modeling, and estimation are sufficiently flawed that the results cannot be deemed reliable.

E. Conclusions With Respect to Econometric Models of Prices

Despite the fact that these four studies all rely substantially on econometric modeling, there are striking differences among them, as summarized in Table 3. As is evident, each employs somewhat different price variables, different criteria for the restructuring event, a

[50] For discussion of the relevant econometrics, again see Kennedy, *A Guide to Econometrics*, op. cit.

[51] Since RTO membership is for utilities and his observation is for states, it is unclear what this statement may mean. Nor is it clear what time period is used for making this assessment. And in any event, restructuring involves elements beyond RTO membership.

different list of control variables, and different types and numbers of observations. Two employ out-of-sample prediction, while the others use the more reliable within-sample technique. Substantively, three of the four come to essentially favorable overall judgments about restructuring.

As noted by Joskow, his and all these studies are initial efforts at empirical assessment of electricity deregulation. As such, both variation in approach and some minor errors might be expected. Most of these studies, however, contain more serious problems than that. There is inadequate attention in these studies to the important data issues of post-restructuring price freezes, stranded cost recovery charges, and excess capacity, among other things. These deficiencies render the conclusions of these studies tenuous or unreliable.

That said, the problems that afflict some of these studies are by no means uncorrectable. In most cases, the issues that compromise one study are adequately addressed in some other study, making clear that sounder work is entirely feasible. Unfortunately, no single one of these studies has addressed all of them simultaneously, and hence none offers reliable and convincing evidence with respect to the effects of restructuring.

TABLE 3
Summary of Econometric Studies of Price

	CERA	**JOSKOW**	**TABER et al**	**FAGAN**
Dependent variable(s): **Electricity Price**	Regional CPI for electricity	Residential Industrial	Residential Commercial Industrial Overall	Industrial
Causal variables	1977	PURPA Independent generators Retail choice	ISO membership	Year, "Restructuring"
Control variables	Fuel price Capital cost	Fuel price Capital cost Generation type (2) Average usage	Fuel price Generation type (6) Climate	Fuel price
Number, type of observations per regression	4 regions x 16 years = 48	51 states x 34 years = 1,734	Approx. 85 utilities x 14 years = 1145	8 years
Prediction method	Out-of-sample	Within sample	Within sample	Out-of-sample
Recognition of **Price freeze** **Stranded cost** **Excess capacity**	 No No Adjusts	 No Recognizes No	 No No No	 No Adjusts No
Brief conclusion	Predicted prices below actual in all regions. Separate index of deregulation related to savings, except in Western US.	Variables for retail competition and share of exempt wholesale generation both associated with lower retail prices.	Variables for membership in auction-based ISOs do not indicate lower prices.	Predicted prices higher than actual prices more often in restructuring states than without restructuring, but effects dominated by other factors.

IV. FIVE COMPARATIVE STUDIES OF PRICE AND COST

This chapter discusses five studies that undertake a quantification of the price or cost effects of restructuring with techniques that are not fundamentally econometric in nature. Two such studies–those authored by CAEM and by Apt–are essentially comparisons of prices before and after restructuring. The studies by Synapse and GED construct alternative prices or costs from accounting data to infer the effects of deregulation. The quantitative analysis in the ESAI study rests on a simulation of the counterfactual prices. We summarize and comment on each in turn.

A. Estimating the Benefits of Restructuring Electricity Markets: An Application to the PJM Region," The Center for the Advancement of Energy Markets, 2003 (CAEM Study)

(1) SUMMARY

The study by the Center for the Advancement of Energy Markets (CAEM) begins with a review of traditional cost-of-service regulation and its inefficiencies. It then goes on to describe the restructuring process in the PJM region and examines the operation of the restructured PJM power pool. In this discussion it makes a number of claims about the operation of the PJM market, including; that the marginal cost of the last bid in the auction market determines the price received by all generating plants, that bids for energy and capacity trace out a supply curve which is the industry marginal cost curve, that the system encourages supply reliability, and that most markets are "reasonably competitive."[52]

Next, the CAEM study discusses sources of expected benefits from restructuring at the wholesale and retail levels. The study asserts that wholesale cost minimization should result from the profit incentive facing energy suppliers and capacity providers. It acknowledges that retail market competition is emerging rather more slowly. It also acknowledges that "some of the customer cost reduction benefit of retail competition is being deferred to pay the transition costs of restructuring."[53] The transition issues that the report mentions are temporary price reductions, together with recovery of transition and stranded costs.

The next part of the CAEM study contains its calculation of the benefits from restructuring the PJM market. It begins with a supply-demand framework, discusses consumer vs. producer benefits from cost reductions, and states its working assumption that "restructuring redistributes producer surplus [the profit gain] from regulated utilities to competitive suppliers, but produces no net change."[54] CAEM next offers a list of 10 possible benefits from

[52] CAEM Study, p. 24.

[53] CAEM Study, p. 37.

[54] CAEM Study, p. 43.

restructuring, such as a decrease in outage rates, construction of new capacity, and increased reliability of the system. While some of these should be reflected in the consumer benefit of lower electricity prices, CAEM argues that some benefits such as environmental improvements are not captured in this way.

Deep into the report, CAEM finally "sketches [its] method" for estimating the benefits of restructuring. That method turns out to be--in its entirety--a simple comparison of the real residential, commercial, and industrial prices in PJM states between 1997 and 2002. Multiplying the change in price by PJM electricity generation in 2002 gives an estimated $3.3 billion in savings for the region in that one year. The report asserts that this comparison "reflect[s] wholesale market efficiencies, the effects of the retail restructuring deal, and the effects of retail competition," but notes it also captures "fuel prices, inflation, and other factors that affect electricity prices in other regions."[55]

CAEM also claims as a benefit from current restructuring efforts the present value of future electricity cost savings that will result from current efforts.[56] These additional benefits are estimated by assuming the same price reduction but a growth in electricity generation over time in accordance with Energy Information Administration estimates. This procedure yields an estimate of consumer benefit in present value terms of $38.8 billion. These savings are also calculated for each PJM state and each consumer class.

In various places in this chapter, the report concedes that the "present value of cost savings reflects the benefits of restructuring efforts plus cost reductions due to other factors," that its estimates for Pennsylvania are based on "benefits post stranded cost recovery, even though most of that recovery will not be complete for another six years,"[57] and that some of the price benefits may be "precarious" because of increases when freezes expire. Nonetheless, it asserts that efficiencies in the wholesale PJM market will be passed along to consumers, making nominal price declines "plausible," and that in any event retail price increases "provide a much needed incentive toward retail competition, which may ultimately make customers better of [sic] than commission mandated price declines."[58]

CAEM makes one effort to separate the effects of restructuring from other factors by examining changes in electricity prices between 1997 and 2002 in three neighboring states that did not restructure their electricity sectors, and for the United States as a whole. Since prices generally declined during this period, the report proposes to subtract from the gross benefits within PJM those that arose in the neighboring non-restructured states of Kentucky, North Carolina and Tennessee. The implication is that any residual must be due to deregulation within

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[55] CAEM Study, p. 47.

[56] The present value represents the equivalent value today of money that will not be received until some future time.

[57] CAEM Study, p. 48.

[58] CAEM Study, p. 48.

PJM, although the study cautions that other factors such as fuel prices and state environmental regulations might also differ among states. Nonetheless, it gives an unqualified interpretation to the differences that it calculates. It concludes that $10.1 billion in savings in present value terms would have occurred even in the absence of reforms, leaving $28.7 billion attributable to restructuring.

The last part of this chapter of the report is devoted to the contention that electricity price reductions have additional "macroeconomic" benefits to the states and regions that have deregulated electricity and hence enjoy lower prices. In support of this proposition, but without further explanation, the report states that "As a first approximation, a simple multiplier of 2 is reasonable."[59] The next and final substantive chapter presents an analysis of the effect of restructuring on the market for capacity.

2. COMMENTARY

The CAEM study does not cast any light on the key issue of the price effects of restructuring electricity markets. Its methodology contains a number of deficiencies and its conclusions are unsupported by its calculations. The major limitations of the CAEM study are as follows:[60]

(1) CAEM's "method" for estimating the price benefits of restructuring is entirely inadequate. The study's approach consists of a comparison of PJM prices in 2002 with prices in 1997, with the difference (adjusted for inflation) attributed to restructuring. Failure to control for other possible causes makes such attribution erroneous. On this crucial question, the study indicts itself. The text states that reliable estimates requires determining "the change in prices to customers due specifically to restructuring, and not due to other factors," and then repeats that "the task of capturing the benefits of restructuring requires isolating the price increment (ΔP) produced by restructuring."[61] Attached to this last sentence is the following footnote: "The relatively large price declines in the PJM region are a result of successful restructuring and other possible factors. An econometric analysis is required to identify the statistical importance of other factors, but is outside the scope of this study."[62] This forthright disclaimer is commendable, but it serves as an acknowledgment by CAEM of the unreliability of its own study.

(2) In addition, while the CAEM study recounts changes that did occur within PJM–for example, the development of an auction based spot market for electricity--the study does not state precisely what "restructuring" means and why it would have caused the price effects

[59] CAEM Study, p. 53.

[60] These comments include some observations made in *Erecting Sandcastles from Numbers: The CAEM Study of Restructuring Electricity Markets*, by Christensen Associates, 2003.

[61] CAEM Study, p. 46.

[62] CAEM Study, p. 46.

examined. Moreover, since PJM is a wholesale market, any direct effects of restructuring would be at the wholesale level, while the study addresses only retail prices. Particularly in current electricity markets, the relationship between the two is very imperfect. CAEM's effort to connect them with a hypothetical supply-demand graph overlooks all the important features of these markets that interfere with the direct translation of wholesale price changes into retail price changes, such as market power, pre-restructuring regulation, post-restructuring price freezes, etc.

(3) In its calculation of the price benefits supposedly due to restructuring, the CAEM study fails to correct for the distorting effect of rate reductions and freezes and of excess capacity, even as it concedes that, for example, New Jersey consumers were only temporarily enjoying 15 percent lower prices due to the regulatory bargain.[63] On the other hand, the study takes a different approach to the analogous issue of stranded costs. It adjusts retail rates in Pennsylvania for such stranded costs, thus crediting restructuring for additional, yet-to-be-realized benefits. This adjustment has the effect of reducing post-restructuring consumer costs by $8.6 billion, or 30 percent of the total.[64] As argued in Chapter II, such adjustment is desirable, but in this case the study makes the one adjustment that favors restructuring, while ignoring others.

(4) CAEM's assumption that consumer benefits will continue at the same rate indefinitely cannot be justified. While the study acknowledges that "some current price declines may not be permanent,"[65] that statement fails to make clear that the mandated rate cuts that CAEM incorporates into its calculations were known to be temporary, and indeed some were already expiring at the time of their study. There was simply no factual basis for the study's assumption of unchanged rate reductions. Moreover, when it does acknowledge the possibility of subsequent rate increases, the report strives to turn them into a consumer benefit, arguing that the "expiration of retail price decreases will encourage the development of retail competition. Hence, benefits estimated here are likely to be understated."[66] This effort to make higher prices appear beneficial to consumers is illogical, at the very least.

(5) The study's effort to adjust the calculated benefits for factors other than PJM restructuring itself is inadequate. Using a "difference-in-differences" technique, CAEM compares savings within PJM to savings over the same period in Kentucky, North Carolina, and Tennessee, three states chosen because they are nearby and were not actively restructuring. One indication that they may not be suitable for comparison purposes is the enormous differences among those "control" states themselves. For example, the present value of cost savings as a percent of 2002 costs–CAEM's measure of savings--in those states is 6 percent, 45 percent, and

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[63] Interestingly, this 15 percent figure is precisely the amount of the rate reduction calculated by CAEM as due to restructuring. Simply put, it would appear that the entirety of the benefit found by CAEM for these consumers was nothing but the initial rate deal.

[64] CAEM Study, Table A1.

[65] CAEM Study, p. 50.

[66] CAEM Study, p. 6.

76 percent. No explanation is offered for this variation, but it surely implies that these states are fundamentally different and hence quite suspect as control states for PJM states. Clearly, a different possible choice of states–for example, any two of these three, or perhaps some other one–would alter the benchmark entirely and produce quite a different conclusion about the benefits of PJM deregulation. Benefits calculated based on an arbitrary and volatile benchmark cannot be trusted.

In summary, the CAEM study falls well short of standards for good empirical analysis. Its methodology is flawed and inadequate, something it virtually concedes. It selectively makes corrections and adjustments in order to strengthen its preferred conclusions. It cannot be relied upon for insight into the actual effects of restructuring.

B. "Competition Has Not Lowered U.S. Industrial Electricity Prices," Jay Apt, 2005 (Apt Study)

(1) SUMMARY

The Apt study begins with a brief chronology of the restructuring of the electric power industry, but its main goal is to examine the effect of restructuring on prices paid by U.S. industrial customers for electricity. Industrial customers are chosen as the focus for several stated reasons: They are said to have both the incentive and the capability to shop for the best price, and are supposedly not subject to retail rate reductions and freezes, as were residential users. In addition, other sectors, notably commercial users, are extremely heterogeneous, making the assessment of the effects of restructuring more difficult.

Apt presents tables of industrial prices for 1990-2004 in five western states, five regulated southern states, and the New England states. He observes that much of the volatility in New England prices is a reflection of their dependence on natural gas, whose price shot up in 2001 and peaked again in 2003. In the case of Maine, these spikes were followed by a decrease in prices due to the opening of new natural gas pipelines.

Apt further notes that, since Vermont has continued to regulate its electricity sector, it is useful to compare Vermont's prices to those in other New England states. The study calculates the average annual rate of industrial price change for Connecticut, Massachusetts, Maine, New Hampshire, New York, and Rhode Island from January 1990 to one month prior to the beginning of each state's "phase-in period" for industrial competition. That calculation of pre-restructuring price change implies a 0.9 percent price increase per year. The corresponding annual rate after the phase-in of competition was a decrease of 1.7 percent per year. Given the importance of the Maine anomaly to these numbers, Apt recalculates these changes without Maine's data and obtains a pre-competition increase of 0.8 percent and a post-competition increase of 2.0 percent for the remaining states, implying an increase in the annual rate of change of 1.2 percent. By comparison, Vermont's regulated prices rose 0.8 percent annually from 1990 through March 1998, and fell 0.8 percent from 2001 to 2003. Vermont's net change of -1.6 percent was therefore considerably better than the experience of the rest of New England (except for Maine). Apt concludes that these data do not support the proposition that restructuring reduced prices.

In the next step of his analysis, Apt calculates the average annual rate of change in

industrial prices for each of 20 states that restructured their electric power industry, first for the period prior to their restructuring and then following restructuring. Their mean pre-restructuring price change was a 0.4 percent increase per year, rising slightly to 0.5 percent after restructuring. (Omitting Maine results in a pre-restructuring value of 0.3 percent and a post-restructuring value of 1.7 percent). Apt compares these values to those for all 50 states plus the District of Columbia. For the latter, the rate of price change in the pre-restructuring period (taken as April 1998 through 2000) was a negative 0.4 percent, followed by a later increase in price at the annual rate of 0.4 percent. These comparisons also provide no evidence favoring restructuring.

Finally, Apt examines individual state data more closely, calculating the difference between the pre- and post-restructuring annual rate of change in industrial price for each. Graphical inspection suggests no correlation between restructuring and the annual rate of price change. Apt then reports that a regression was run on these differences in the rate of price change, with "restructuring" as the independent variable. The regression confirms the absence of a relationship between restructuring and price change in these data.[67] The R^2 of 0.01 indicates virtually no correlation between the two variables. Restructuring in the electricity industry, Apt concludes, "has not led to lower industrial prices, nor to decreased rates of annual price increases."[68]

(2) COMMENTARY

The Apt study takes what appears to be a relatively straightforward approach to the question of the effects of electricity restructuring. Both its conceptual framework and methodology, however, are problematic. The major concerns with this study are as follows:

(1) The outcome variable for Apt's study–the annual rate of price change–does not seem to be a well-chosen criterion for measuring the performance effects of electricity reforms. Successful reforms should bring about efficiencies, competition, and ultimately a lower level of price, but not necessarily prices that increase (or decrease) at a different rate. The rate of change of prices should largely reflect input costs in either case. To that extent, the finding of a lesser rate of change after restructuring can be consistent with either successful or unsuccessful restructuring in terms of price level. Apt offers no explanation or motivation for his choice. Moreover, his statement that the study finds that restructuring has not led to lower prices or lower rates of change is incorrect insofar as his study focuses exclusively on rates of change.

(2) In addition, this study's method for calculating the annual rate of price change is likely to introduce errors in variables in several respects. First, the period over which the annual rate of change variable is calculated differs for each state, creating a mismatch and errors in the variables. Then as noted previously, restructuring is a process that unfolds progressively so that using a single point in time converts a continuous variable into a dichotomous one, introducing further errors. And finally, the phase-in period varies enormously across states, ranging from March 1998 in Massachusetts to March 2002 for Oregon. But during 2000 and 2001, electricity

[67] Jay Apt graciously provided these data, permitting replication of his results.

[68] Apt Study, p. 58.

prices changed considerably for reasons having nothing to do with restructuring. For those states with an early retail choice phase-in, the 2000-01 price experience is part of their post-restructuring rate of change, while for other states with later phase-ins, that price experience is integrated into its pre-restructuring calculation. This process introduces further errors into variables of interest.

(3) By annualizing the rate of change, Apt overlooks possibly relevant differences in the rate of price change in certain years. For example, if prices were beginning to fall just prior to restructuring, annualization over a longer period might result in an incorrect benchmark for evaluating the post-restructuring price. In general, discarding detailed information is a risky statistical practice. On the other hand, it should be noted that Apt's use of annualized rates of price change might work to his advantage in capturing the more discrete change due to restructuring. As a demonstration, suppose that prices were trending upward at a 3 percent annual rate prior to restructuring, but that reform caused price to fall by 2 percentage points (that is, to a 1 percent increase) in the first year after restructuring, after which they resumed their historic 3 percent annual increase. Annualizing post-restructuring prices over two or more years would give a rate less than 3 percent. While this smaller rate is only because of the first post-restructuring year, the calculation nonetheless results in a lower rate for comparison purposes, to some extent offsetting the problem with the rate of change.

(4) The focus on differences in annualized price change before and after restructuring creates difficulties in controlling for other possible influences. Apt initially chooses non-restructuring states as the comparison group, but obviously there is no such thing as a pre- or post-restructuring period for such states. Apt therefore picks two arbitrary time periods to use in an attempt to control for the possible influence of other factors on electricity prices during this time. The study specifies the benchmark or "pre-restructuring" period for non-restructuring states to be January 1990 through March 1998, and the subsequent or "restructuring" period to be January 2001 through December 2003. For each, the annualized rates of change in prices are calculated, and compared to pre- and post-restructuring rates of change for states that did indeed restructure. These periods are quite arbitrary, however, and also different from any of the periods over which the same calculation is made for restructuring states. This approach creates mismatches and yet further errors in the variables. Also, curiously the study compares this calculated figure in restructuring states relative to *all* states, a group that obviously includes the restructuring states as well as those that did not restructure. The better comparison group would be all non-restructuring states.

(5) Finally, the study chooses to address industrial prices in order to avoid issues such as price freezes, stranded costs, etc., that confound residential prices. But as noted in Chapter II, industrial prices in many states were also subject to rate reductions and freezes, so that the post-restructuring data relied upon by Apt are by no means free of such difficulties.[69]

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[69] Of course, since Apt ostensibly finds restructuring to have had no effect, failure to correct for post-restructuring freezes–a correction that would raise such rates–should not reverse his conclusion. In any event, excess capacity and stranded cost remain issues.

In summary, the Apt study's focus on the rate of price changes as well as some other matters cast doubt on the reliability of this study's conclusions.

C. "Electricity Prices in PJM: A Comparison of Wholesale Power Costs in the PJM Market to Indexed Generation Service Costs," Synapse Energy Economics, 2004 (Synapse Study)

(1) SUMMARY

The Synapse study analyzes electricity generation costs before and after two changes: 1) the retail restructuring in states within the PJM region, and 2) the restructuring of the wholesale markets in PJM with the introduction of markets for energy, capacity and other services, beginning in 1998. Specifically, this study compares the actual wholesale power costs (WPCs) paid by utilities under deregulation to the implied cost of generation that would have occurred if regulation had continued. To implement this approach, Synapse engages in extensive reworking of individual company financial and operations data to construct the implied generation service costs for three PJM companies. Most of the report consists of description of the procedures employed in developing the data series.[70]

In the first part of the study, Synapse provides some general information on retail deregulation in PJM and a closer look at three companies to be examined. These are Delmarva Power & Light in Delaware (Delmarva), Jersey Central Power & Light in New Jersey (JCPL), and the Pennsylvania Electric Co. (Penelec). These are said to represent a relevant range of PJM utilities in terms of geography and prices. This chapter also contains a description of the wholesale markets in the PJM Interconnection system, namely, the markets for energy, capacity, spinning reserves, regulation (of power), and transmission rights. Since the energy and capacity markets account for almost the entirety of costs, calculations of the wholesale power costs are based primarily these two markets.

Actual wholesale power costs are calculated in the second substantive section of the report. Energy market costs are represented by load-weighted locational marginal prices.[71] Locational prices are calculated separately for each of the three utilities to capture their different purchase cost experience. By contrast, capacity costs are essentially the same for each company in PJM East in any given year. Wholesale power costs are the total of both energy and capacity and are calculated by Synapse for the whole of PJM East region as well as for each of the three examined utilities by year from 1999 to 2003. The results show that PJM East average costs have varied from a low of $30.72 per MWH in 2000 to a high of $42.64 in 2003. Costs for Delmarva and JCPL are close to the PJM East averages in each year, while Penelec's costs are systematically lower. These numbers constitute one part of the comparison to be drawn.

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[70] One of the principle authors of the Synapse Study, Bruce Biewald, graciously spent time explaining the analysis.

[71] These are prices that reflect the differences in costs of delivering electricity to different parts of PJM, known as nodes.

The next part of the report confronts the more difficult task of constructing counterfactual generation service costs (GSC) for pre-deregulation years. GSCs reflect the utilities' generation capital financing and operating expenses, as calculated for a base year under cost-of-service regulation. This exercise involves unbundling of costs in a base year and then indexing those costs to future years. In the unbundling step, Synapse uses Federal Energy Regulatory Commission Form 1 data to prepare pro forma financials for a hypothetical generation-only company based on each of the three companies chosen for study. This is done for the pre-restructuring base year of 1996.[72] Base year GSC revenue requirements consist of operating expenses, return on rate base, working capital allowances, and adjustments for deferred taxes and investment tax credits. Operating expenses include various O&M expenses, production plant costs, fuel costs, purchased power expenses, as well as allocations to generation of a number of other utility-wide cost items.

GSCs for subsequent years are obtained by indexing initial values. For production costs, the indexing adjusts base period costs for actual load growth, sales and purchases, and locational fuel cost indices. It is assumed that no new generation is built and that any additional energy needed for load is obtained at the market price. Other cost elements are adjusted in accordance with procedures and assumptions set out in this chapter. The resulting indexed GSCs are calculated for all three companies for five years, yielding the second set of costs needed for the comparison.

The final part of the Synapse report compares the two sets of costs described above in a series of tables and graphs. It begins, however, by noting two unavoidable defects in the data: (1) the indexed GSCs contain stranded costs, and (2) the capacity surplus in PJM distorts recorded costs. That said, GSC costs were higher than WPCs for four years out of five for Delmarva and Penelec, and for all five years in JCPL's case. The difference between actual wholesale power costs and the implied generation service costs are fairly modest for Penelec but considerably larger for JCPL. In addition, the comparison indicates that the actual wholesale costs were more volatile than the counterfactual ones.

Based on these observations, the study draws its main conclusion that "while PJM deregulated costs fluctuate year-to-year, on average, the deregulated rates appear to have been lower during this five year period than those generation rates that would have existed under a business as usual, regulated environment."[73]

(2) COMMENTARY

The Synapse methodology--constructing counterfactual costs in the absence of restructuring–is a novel approach to the question of the effects of reform. Its strength lies in the ability to use actual data to infer such costs, but therein lies its limitations as well.

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[72] The report states that data for 1997 were used for Penelec due to problems with 1996 FERC data for that company.

[73] Synapse Study, p. 32.

Synapse is commendably forthright in stating some caveats about its methodology and results. These are as follows: First, the indexed GSCs rely on "highly simplified assumptions"[74] about trends in various cost items, incorporate stranded costs, and fail to reflect any productivity improvements in utility's generation or overhead operations. Second, the WPCs are calculated based on locational wholesale prices and hence include some congestion-related transmission cost, whereas the GSCs do not. Third, the WPCs do not necessarily translate into actual prices to customers, as retail adders, marketing costs, and market power may divorce the two series. Fourth, the WPCs in these years have been unusually low due to capacity surpluses in the PJM region resulting from new generating plants. And fifth, the study examines only three utilities, and while they are chosen to be representative, that cannot be assumed to be the case without further study.

It is interesting to note that all of these caveats, but one, operate in the same direction, that is, they exaggerate the likely cost advantage of the WPCs over the constructed GSCs. The exception concerns the difference in treatment of transmission costs between WPC and GSC, a correction that would lower WPC.[75] Moreover, several of these caveats are potentially quite large, sufficiently so that the measured advantage of post-restructuring costs might be substantially narrowed or even reversed. We elaborate on and add to these issues as follows:

(1) Most generally, the constructed counterfactual costs are largely assumption-driven. None of the cost elements making up the GSC arises from freestanding market transactions, and hence their reliability is dependent on the assumptions used to construct them. Some of the stated assumptions seem reasonable, whereas others are harder to assess. And it is impossible to know which are most important. The Synapse study offers no sensitivity analysis to cast light on the issue of how the findings vary with reasonable alternatives to its assumptions.

(2) A related concern is that a significant part of the constructed GSCs derives from overhead and common cost items such as administrative and general expenses, certain taxes, etc. Synapse uses cost allocation formulas to apportion these costs, formulas based on such things as generation's share of sales or plant or other underlying factors. While in principle entirely appropriate, this procedure relies on formulas that have a significant element of arbitrariness in them, so that generation might be assigned a significantly different share of cost under plausible alternative formulas. Similar considerations affect its allocation of major cost items between the electric and gas operations of Delmarva.

(3) A further set of questionable assumptions concern indexing GSCs for future years. For example, the study states that all new energy needed for load is obtained at PJM market price rather than at some price determined by the cost of new generation or at the price of a new contract for the purchase of power from existing generation. But PJM market price may not provide an accurate reflection of equilibrium price during the study period, as indeed Synapse

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[74] Synapse Study, p. E5-1, p. 32.

[75] This actually is confusingly stated in different places in the Synapse Study, but from discussions with its author, it appears this is the reason for the caveat.

acknowledges in another context.[76] Another example concerns the treatment of purchases and sales, which at least for Penelec constitutes a substantial part of its operations. Synapse uses FERC Form 1 data to estimate the prices of purchases and sales, noting in the process that these might not be correct since the actual prices in many of these years reflect deregulation itself.

There are numerous other assumptions and adjustments employed in the data analysis of the Synapse study. These are described with considerable care in that study, but it is also clear that for any study based on constructed values–even the most careful and candid--it is difficult for an outsider to determine the adequacy of many of its assumptions or the sensitivity of the results to them.

D. "Putting Competitive Power Markets to the Test: The Benefits of Competition in America's Electric Grid–Cost Savings and Operating Efficiencies," Global Energy Decisions, 2005 (GED Study)

(1) SUMMARY

In its 2005 report, Global Energy Decisions analyzes three aspects of wholesale electric market restructuring in the Eastern Interconnection region: the consumer benefits from the introduction of unregulated wholesale electricity suppliers, the effect of this restructuring on the operating efficiency of power plants, and the benefits of PJM expansion with the inclusion of new member utilities in 2003-04. The GED report asserts that these policies promote competition and "are unequivocally producing consumer benefits."[77]

With respect to wholesale power deregulation in the Eastern Interconnection, the study attempts to quantify consumer benefits by comparing costs under two scenarios. The first, termed the "With Wholesale Competition" case, is simply based on the actual operating data from wholesale power markets for the period 1999-2003. These markets are divided into two sectors: a "competitive sector," comprised of exempt wholesale or merchant generating units that sell their energy and capacity on the open market, and a "regulated sector" of traditional regulated utilities obliged to serve native load retail customers with their own generation plant and with power purchased from the competitive sector.

The second case, termed "Without Wholesale Competition," involves the construction of counterfactual cost data and a simulation of market operation as if "the market remained as traditional, vertically integrated utilities operating in a regulated environment without wholesale competition."[78] More specifically, this counterfactual assumes the absence of unregulated merchant power plants so that all power is internally generated at regulated utilities' traditional costs, no regional transmission organizations (hence assuming continued pancaked transmission rates), and finally, marginal cost-based contracts instead of market-based pricing for wholesale

[76] Synapse Study, p. 32.

[77] GED Study, p. RS-1.

[78] GED Study, p. RS-3.

energy transactions. The counterfactual therefore involves the replacement of power currently purchased by utilities with power from regulated generation plant plus power acquired at pancaked transmission rates. The various cost items making up these totals are constructed from utility financial and operating statements.

The next step taken by GED is to simulate market operation for the Without Wholesale Competition case. For purposes of this study, the Eastern Interconnection power market is divided into 29 market areas, delineated by critical transmission constraints. Within each such area, GED assumed the absence of transmission constraints and therefore zero costs for power transmission. Its proprietary Strategic Planning software then simulates the operation of individual generators, utilities, and control areas, based on a model that searches for all economically eligible exchanges of power across zones. Together with some additional adjustments, these results yield estimates of the costs that would have risen under continued regulation.

Finally, the outcomes of two models are compared, with the difference representing estimated consumer benefits from wholesale restructuring. Cumulatively over the five-year study period, regulated utilities actually paid the competitive sector $13.7 billion for energy and capacity, but in GED's assessment would have spent $28.9 billion in electricity generation operating expenses in the absence of wholesale competition. Accordingly, consumer benefits are said to total $15.1 billion over the whole study period.[79]

The second section of this report is devoted to an evaluation of the operating efficiency of power plants before and after wholesale competition. Its method is simply to compare various measures of operating efficiency over the 1999-2003 period and to conclude that any improvements were due to competition. Moreover, for this exercise GED analyzes the entire North American generation fleet, including not just regions within the United States where restructuring has occurred, but regions where they have not, plus Canada and Mexico. GED finds that such measures as length of fueling outages, O&M costs per MWH, heat rates, and capacity factors have improved over the five-year period and then, without further elaboration, attributes these to "the skill of experienced fleet operators, the standardization of procedures and maintenance, and the combined buying power for fuel, equipment, and supplies."[80]

In the last part of the report GED examines the benefits for wholesale power customers from the 2003-04 westward expansion of PJM to include Commonwealth Edison (ComEd), American Electric Power (AEP) and Dayton Power & Light (DPL). The report indicates the benefit it seeks to measure as simply the reduction of pancaked wheeling charges between these three utilities and PJM energy markets. The methodology is again a cost comparison within the Eastern Interconnection, this time between production costs the actual PJM members in 2004 versus the "without competition" case, defined as a scenario where ComEd, ARP, and DPL had

[79] An alternative "Low-Capital Cost" variation, based on a different mix of new generation plant, results in a benefit "floor" totaling $9.4 billion.

[80] GED Study, p. RS-8.

not joined PJM.[81] This comparison is based on different GED simulation software.

The comparison of the costs under these two scenarios implies $85.4 million of annualized production cost savings during 2004 for the Eastern Interconnection and $69.8 million of savings for PJM. These estimates are an extrapolation to the full year of part-year estimates since the three new utilities joined PJM during the calendar year. GED observes that this favorable conclusion supports the results of a separate PJM analysis of prices in 2003-04.

(2) COMMENTARY

The study by Global Energy Decisions combines two different methodologies–constructed costs, and market simulation–each based on a number of crucial assumptions. Several of these are problematic, most importantly the following:[82]

(1) The distinction that the study draws between "with" and "without" wholesale competition seems excessively sweeping. As previously noted, restructuring has been a multi-faceted process over time, but this study takes the exaggerated view that "without competition" means that no reforms whatsoever have taken place. Even simple rule changes preventing pancaked transmission rates are automatically viewed as part of the broader restructuring of the wholesale markets and are put into the "with competition" scenario. Hence, some major benefits that GED attributes to restructuring are perfectly attainable without the entire wholesale market restructuring package, and indeed, one might predict they would have occurred without it.

(2) The study's assumption of no transmission constraints and hence zero transmission costs within each of the 29 market areas in the Eastern Interconnection is incorrect, sufficiently so as to undermine the analysis on which it is based. As has been pointed out, its "NY East" area has major constraints between upstate New York, New York City, and Long Island.[83] The "Carolinas/Southern Company/Grid Florida" market area has major constraints along the Florida peninsula interties. By overlooking such constraints, the GED study is certain to introduce errors into its cost estimation.

(3) GED's estimated $15.1 billion in benefits from competition derives from two sources, both of which are doubtful. More than half of that amount–$8.9 billion, to be exact–is the result of what the study terms the "shift of expense and risk of building power plants from utility consumers to the competitive plant owner and operator and the competitive power supplier

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[81] The reason why simply adding these utilities to PJM constitutes "competition" is not made clear.

[82] These comments include some observations made by Howard Spinner in *A Response to Two Recent Studies That Purport to Calculate Electricity Restructuring Benefits Captured by Consumer*, 2005, and by Christensen Associates, *Global Energy Decision's 'Putting Competitive Power Markets to the Test': An Alternative View of the Evidence*, 2006.

[83] Christensen Associates, *Global Energy Decision's "Putting Competitive Power Markets to the Test": An Alternative View of the Evidence*, p. 10

generally."[84] But in practice this consists of the losses borne by new generators in the post-restructuring market environment, losses that, as noted previously, represent a temporary post-restructuring disequilibrium. Such a "benefit" will persist only if there is a never-ending supply of misinformed investors who are prepared to enter, build, and take losses on generation indefinitely. In contrast to that implausible scenario that underlies the GED calculations, the long run equilibrium will surely be characterized by full capital cost recovery by non-regulated generators, eliminating most of GED's claimed consumer benefit.

(4) The other major part of the estimated benefit derives from the assumption that new plants would have been built by regulated utilities at the same capital cost as in the past. GED calculates these regulated unit costs to be so much greater that, despite the smaller amount of capacity under regulation, they far exceed costs under competition. The study claims this difference is a $5.8 billion "cost of regulation," but in reality it is based on several dubious assumptions. For example, regulated utilities almost surely would have adapted their generation mix to changing fuel costs and other factors, rather than replicating historical practice as assumed here. In addition, the competitive sector's dependence on new gas-fired generation may have seemed prudent during the study period, but subsequent high natural gas prices may undermine that advantage. Overall, these two factors--temporary generator losses and excessively costly new capacity, both of which are doubtful–account for $14.7 of the $15.1 billion in total gains from restructuring that this study finds.

(5) The GED study's second exercise–assessing changes in the operating efficiencies of the North American generation fleet–is, for two reasons, a misguided exercise. For one, its universe consists of all plants in Canada and Mexico as well as those in the United States. No insight is provided into factors that might affect non-U.S. plants, and whether they are appropriately included in the comparison group.[85] In addition, the study categorizes plants into traditional and competitive groups. The former consists of "investor-owned utilities, municipalities, and cooperatives that are subject to retail rate regulation. Competitive utilities are best defined as independent power producers and other generators that are not subject to rate regulation."[86] Oddly and without explanation, these definitions differ from those advanced in the first part of this study. Moreover, the study's regulated sector is extraordinarily heterogeneous, including traditional rate-regulated utilities as well as rural electric cooperatives. The level of the co-ops' rates are set in an entirely different manner than those for traditional utilities subject to rate of return regulation. And finally, these two categories–traditional and competitive entities--are not correctly posed. An IOU in a restructured wholesale market but with retail rates that remain heavily regulated would seem to fit neither category.

(6) The study's final exercise is called "The Impact of Regional Transmission

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[84] GED Study, p. RS-20.

[85] Unless, of course, some plant in Mexico or Canada has been subject to restructuring. The GED Study is silent on issues of numbers of plants, location, restructuring status, etc.

[86] GED Study, p. RS-8.

Organizations" but in reality it deals only with expansion of the PJM market. Moreover, the exercise is not an effort to understand fully the consequences of RTO expansion, but rather only to calculate the predictable results of eliminating pancaked transmission rates–something that could be accomplished without adding additional complexity to RTOs by having these entities operate locational energy, capacity, and other markets. Moreover, if this or any other "benefit" actually did require an RTO, a true assessment of the RTO's value would logically also require measuring any offsetting costs. As we shall see in a later chapter, such costs appear to be substantial.

In summary, the GED study's methodology is fundamentally flawed. Crucial assumptions, data adjustments, and inferences are incorrect. Its conclusions cannot be relied upon for insight into the effects of restructuring in the PJM region or elsewhere.

E. "Impacts of the PJM RTO Market Expansion," Energy Security Analysis, Inc., 2005 (ESAI Study)

(1) SUMMARY

Commissioned by PJM itself, the purpose of the ESAI study is stated in its title, namely, to evaluate the impact of PJM's expansion both on its original service territory and on its expanded territory following the addition of member utilities starting in 2002. The study emphasizes that while it does perform a quantitative assessment of price benefits from expansion, that calculation represents only one part of its impact evaluation. Much of the rest of the study is devoted to discussion of other outcomes measures

The ESAI study notes that PJM expansion in 2002, 2004, and 2005 incorporated five new utilities in seven states, nearly tripling its original service territory, customer numbers, generating capacity, and transmission lines. As a result, ESAI casts PJM as a broad "agent of change" in the industry, altering market rules, interconnection rules, and transmission system management rules over a larger and more diverse set of generation and transmission assets. The study insists that PJM expansion has had various "more subtle, and ultimately more important consequences"[87] than a simple reduction in energy price.

The first of these other consequences is the degree of liquidity in the market for power contracts. Data series are presented showing favorable long-term trends in PJM with respect to short-term market volumes, longer term market volumes, bid/ask spread, and market bias. Most of these series show pronounced gains immediately after restructuring in 1998, declines in the 2001-02 period, and then some recovery. ESAI concludes that PJM expansion is associated with net gains relative to the pre-restructuring period. These various factors are said to be enormously valuable to market participants. The study states that "If, over the course of the decades in which these efficiencies must be measured, the price of energy turns out to be only $2/MWH less that in a world of monopoly agents, the economic benefits of the spread of PJM's platform would be measured at $1.4 billion per year...or $15.7 billion over a 20-year planning period..."[88] As the

[87] ESAI Study, p. 5.

[88] ESAI Study, p. 39.

word "if" suggests, there is little hard evidence to support the $2 figure.

The next section of the study assesses the reliability effects of integration by examining the PJM capacity market. ESAI discusses the new reliability pricing model (RPM) that was introduced in 2004 to encourage the construction of generation capacity that would improve reliability. The stated aim of the RPM was to better reflect the value of reliability services as provided through generation capacity and any regional differences in the costs of generation facility maintenance. ESAI values the RPM by predicting the increase in the energy charge that would otherwise occur due to capacity reductions, then assumes RPM will prevent all of that increase. By treating that magnitude as the benefit of PJM's capacity market under the planned RPM, it concludes that this program will provide between $500 million and $5 billion in annual savings.

Next, the ESAI report addresses the energy price effects of PJM integration. Its methodology involves power flow simulations. The simulation software requires specification of generator data, system interface constraints, and import/export flows as inputs. It then optimizes system operation under normal operating limits and also under violations that might arise in various contingencies. The result is a set of prices at each node, from which can be determined load-weighted average prices in each area. ESAI acknowledges that the integration at issue is essentially the flow of low-cost energy from PJM West to PJM East, a transfer that must produce model benefits. The report then states that exact amount of these benefits depend on "a host of necessary assumptions, among which the most important is input fuel prices."[89] Its assumptions lead to an estimated energy price difference of $0.78 per MWH. Given PJM consumption, the reduction in PJM area energy costs is calculated at about $500 million.

This section reinforces this estimate by examining generation dispatch benefits (pre- and post-PJM integration), price trends in PJM and associated markets (on-peak and off-peak prices), trends in heat rate (a measure of the energy-efficiency of generation, as measured by the heat content of the fuel required to generate a kilowatt-hour) and management of regional price risks with the help of financial transmission rights (FTRs).[90] It notes, for example, that FTR trade volume rose from a few hundreds of MWH in 1999 to over 30,000 MWH in most months of 2005, thus permitting locational price risks to be better managed. In addition, power flow transfers between PJM's original areas and new areas have generally increased since integration, which ESAI asserts is confirmation that the PJM design has improved the optimization of generation.

The final two sections of the ESAI report address the effects of PJM expansion on electricity trading volumes and on innovation. As described in the study, ESAI and PJM staff

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[89] ESAI Study, p. 58.

[90] FTRs in theory provide the holder with the rights to revenues received for congestion on a given portion of the transmission system. Congestion revenue is paid when more expensive generators must be dispatched because there is no room on the transmission lines to accommodate power from less expensive sources.

developed data sets on metered power flows across individual lines making up each of the external interfaces prior to expansion. These were then compared to the analogous post-expansion flows. The report documents increases in power flow transfers between PJM's original territory and its new regions, which ESAI concludes is a measure of the benefit of expansion. As for innovation, the ESAI study simply asserts that PJM has been "an engine of innovation" spawning many innovations in its pursuit of becoming a competitive power market.

(2) COMMENTARY

The ESAI study consists of an estimate of energy cost savings from PJM integration and a variety of other effects that it claims are ultimately more important. Both its estimate of savings and its discussion of other effects are problematic. The major concerns are as follows:[91]

(1) The energy cost estimation technique is a "black box." Power flow simulations are useful in implementing operating protocols and anticipating various contingencies, but they are not designed as methods for quantifying costs of alternative structural designs. The outcomes are therefore subject to wide margins of error, something that ESAI neither calculates nor even acknowledges. In the present case, ESAI notes that its simulation procedure requires a "host of necessary assumptions." Only a few of these are reported in this study and no sensitivity analysis of alternative assumptions appears to have been undertaken.

(2) Problems with ESAI's methodology are confirmed by certain paradoxical results that it generates. The report describes how the simulation produces a set of load-weighted prices for each load level under PJM expansion. These prices are then compared to actual prices for each year, the difference being the price benefit of expansion. Since actual prices are the outcome of optimal generation dispatch within narrower pre-expansion areas, the results of simulation *must* show benefits from post-expansion optimization, or at worst no difference. Yet ESAI's simulation finds that in some cases global optimization is actually inferior to suboptimization. Tables 1 and 2 in Appendix 1 of the ESAI report show higher price under the assumption of expansion and global optimization for three of eight load levels in 2005 and four levels in 2010. While the reasons for these anomalies are difficult to discern, this quick check establishes an apparent error of this simulation process and of the benefits estimate that it produces.

(3) Many of the other benefits of PJM expansion that ESAI dwells on are based on mere assumption, speculation, or unfounded assertion of causation. For example, none of the beneficial changes in liquidity documented in this report are necessarily related to PJM expansion. Rather, several have occurred in all power markets, and others are simply the effects of recovery from various market problems in 2000-01. As for ESAI's claim about possible improved efficiency in forward power prices, the study "acknowledge[s] from the outset that PJM's installed capacity (ICAP) market is not ready for this kind of test."[92] Several of the charts on which ESAI relies for its conclusions about market convergence are nothing more than

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[91] These observations draw in part on *A Review of "The Impacts of the PJM RTO Expansion" by Energy Security Analysis, Inc,* Christensen Associates, February 2006, p. 1

[92] ESAI Study, p. 29.

overlaid lines drawn to show apparently narrowing differentials. No statistical tests are offered and, indeed, visual inspection of several suggests that apart from very high differentials at the outset of the time series, there may be no actual trend whatsoever.

(4) The study endorses FTR markets as a hedging mechanism based on their apparent effectiveness in the short term. Yet since FTR contracts extend only for one year, they are irrelevant as a hedge against transmission price risk in the longer term. ESAI indirectly acknowledges this fact, by stating that "There needs to be additional progress in the depth and liquidity of longer-dated contracts." The absence of such instruments does not diminish ESAI's enthusiasm or conviction about the results. Immediately after the above statement, the study goes on to say, "given the confidence that we believe market participants have in the PJM platform, we believe these liquidity improvements will continue."[93]

(5) Alternative examinations of data have caused some who have studied electricity restructuring to question ESAI's conclusions with respect to reductions in the bid-ask spread and trends in heat rates. ESAI used Platt's data on bid-ask spreads in the day-ahead market, finding reductions that imply efficiencies perhaps as large as $1.4 billion. Intercontinental Exchange (ICE) data examined by Christensen Associates show that bid-ask spreads–seemingly more carefully measured by ICE--actually increased over this same period.[94] In addition, ESAI's conclusion that market heat rates have declined after PJM expansion is not supported by Christensen Associates' examination of PJM West data, which suggest that heat rates at best have remained the same. Without access to the underlying data, it is impossible to assess these conflicting claims, but several statements in the study suggest ESAI is inclined to find benefits that may well be elusive.

In summary, the ESAI study fails to offer a balanced assessment of PJM expansion. Its reliance on simulation is misplaced, and its other demonstrations flawed. Its conclusions cannot, therefore, be relied upon.

F. Conclusions With Respect to Other Quantitative Studies of Restructuring

These five quantitative but non-econometric assessments of electricity restructuring differ in many ways. As shown in the summary presented in Table 4, they posit different performance variables, use different restructuring variables, control for different other influences, have different types and numbers of observations, and draw on different methodologies. Some of their judgments in these areas are defensible, others less so.

Most involve some type of fairly straightforward comparison of prices or costs across time or place. Often these studies use a true "difference-in-differences" approach, which requires care in selecting the control group. Others involve constructed or counterfactual prices or costs based on various assumptions and judgments. Still others rely on simulations to obtain

[93] ESAI Study, p. 33.

[94] Christensen Associates, *A Review of "The Impacts of the PJM RTO Expansion" by Energy Security Analysis, Inc*. pp. 3-4.

estimates of performance outcomes. Most have significant limitations to their analytical techniques, diminishing the reliability of their conclusions, but few acknowledge those limitations. It should nonetheless be noted that the methodologies used in these studies represent a range of interesting and promising approaches that, with appropriate care, might be used in further evaluations of restructuring.

TABLE 4
Summary of Comparative Studies of Price and Cost

	CAEM	**APT**	**SYNAPSE**	**GED**	**ESAI**
Performance variable	Prices: Residential Commercial Industrial	Rate of change in industrial prices	Wholesale Costs	Retail prices	Wholesale price
Restructuring variable	None	None	None	With, without wholesale competition	PJM expansion vs. no expansion
Control variable(s)	Non-restructuring states	Non-restructuring states	Constructed counterfactual	Constructed counterfactual	Simulated counterfactual
Observations	PJM states, 1997 and 2002	All states, 1990 - 2003	3 PJM utilities	Eastern Interconnection, 1999 - 2003	PJM East vs. PJM West
Analytical method	Differences in differences	Differences in differences	Comparison	Comparison	Simulation, comparison
Brief conclusion	Substantial savings found in restructuring PJM territory	"Restructuring" not significant in regression on differences in rates of change.	Actual costs less than implied regulated costs, although not necessarily large differences	Substantial consumer benefit from restructuring	Significant cost reductions in larger control area

V. THREE DESCRIPTIVE STUDIES OF RESTRUCTURING

In contrast to the studies previously reviewed, the remaining three studies are not quantitative in nature nor do they raise such broad questions as the overall merits of restructuring. One is a law review article chronicling the rise and fall of Enron and the lessons learned from that experience about electricity markets and regulation. The other two are essentially internal evaluations of institutions operating in the restructured electricity industry– the first a discussion of the benefits and costs of ISOs and RTOs by the ISO/RTO Council, the other an assessment of New York State's restructured electric and gas markets by the staff of that state's Department of Public Service. We review each of these in turn.

A. "Can Energy Markets be Trusted? The Effect of the Rise and Fall of Enron on Energy Markets," Jacqueline Weaver, 2004 (Weaver Study)

(1) SUMMARY

The 2004 law review article by Jacqueline Weaver discusses in great detail the story of Enron's emergence as an innovator and major player in energy markets, and eventually as one of the parties responsible for manipulation of those markets and for the rethinking of deregulation that has ensued. Along the way, Weaver addresses California's experience with deregulation, FERC's effectiveness as an overseer of deregulated markets, and the implications of all these events for trust in electricity markets and deregulation generally.

The first part of the article provides background information on Enron and the markets in which it operated. Enron began as a natural gas pipeline company in 1985, but as electricity began to be considered for deregulation, Enron saw new opportunities. For example, with gas being traded as a fuel for generators on spot markets, Enron created the Gas Bank which permitted producers to "deposit" gas in the bank under long-term purchase contracts with Enron, thereby guaranteeing the producers a steady cash flow. Gas consumers also entered into multi-year contracts with the bank, paying a premium for a guaranteed gas supply and large volumes. The Gas Bank broadened the market, reduced price volatility, and earned Enron considerable profit for the risk it bore.

Enron became the largest nationwide marketer of both gas and electricity by the end of the 1990s, handling almost one-quarter of all gas and electric trades. Beyond that, Enron started to sell weather derivatives, established Enron Energy Services to market long-term contracts for customized energy services to large industrial users, and launched its e-commerce Web-site EnronOnline, which offered over 800 various products. But for all its innovation and bravado, Enron's profitability was always an issue, according to Weaver. The company invested in numerous bad deals and it was not clear that either its Energy Services division or Enron Online truly profited the company. Its finances came under suspicion during 2001 and in December of that year, Enron declared bankruptcy.

The next part of the article discusses California's energy crisis and Enron's role. It is now well understood that Enron traders invented a number of schemes for gaming the system

and increasing profits--withholding power, affiliate abuse, manipulating gas and electricity price indexes, all the while lobbying regulators to rewrite existing rules so Enron could provide even more energy services. Enron's conduct and contribution to California's crisis are documented in FERC's *Final Report on Price Manipulation in Western Markets*, issued in March 2003. But Weaver points out that this report stands in contrast to FERC's rather slow actual response to the situation in California. FERC took three months to even open an investigation. The eventual FERC order, some seven months after the crisis began, was accompanied by a staff report blaming California's problems on flaws in its market design and on a supply/demand imbalance in power markets and finding no evidence of market power or any "gaming" of the system. It was not until June 2001 that FERC finally imposed interstate power price caps, bringing an end to the worst of California's crisis.

Weaver then focuses on the reforms implemented by Congress, FERC, and the electricity industry after the bankruptcy of Enron. Members of Congress introduced bills that proposed to prohibit "round-trip trading"[95] and "market manipulation" and to increase penalties for violating FERC orders. FERC reforms were numerous — a new Office of Market Oversight and Investigations, changes in the way data are reported, a new screen for market power, a single set of standards of conduct to govern affiliate transactions, and the proposed standard market design intended to implement aggressive control over wholesale electricity markets throughout the United States. Weaver recounts a number of industry self-reforms, noting that their voluntary nature casts some doubt on their efficacy.

Two additional sections of this article deal with stalled energy restructuring and the future of electricity reforms. Then a concluding section returns to the central question of the study, namely, whether energy markets can be trusted. According to Weaver, "the easy answer is: no. They cannot be trusted to work without a high degree of government intervention that true believers will continue to find offensive and continue to criticize as retarding the benefits that markets can provide."[96] Weaver proceeds to ask whether electricity deregulation might not have resulted in net private and public sector costs. Weaver suggests that if one takes into account California's losses and considers them part of deregulation's costs, "then past and future benefits of both wholesale and retail restructuring nationwide must total in the many billions, simply to provide net benefits above the massive red ink spilled in California."[97]

(2) COMMENTARY

An enormous amount has now been written both about Enron, about California's electricity crisis, and about FERC's conduct as regulator. Many of the suspicions originally

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[95] Round-trip trading involved the transfer of power out of state, after which it could be imported back in at much higher price, due to the fact that necessary imports were paid their bid price, rather than the common price set at the state auction for routine supply.

[96] Weaver Study, p. 13.

[97] Weaver Study, p. 141.

voiced by some, and rejected by others as paranoia, have proven to be true. Weaver's article is notable for the thoroughness with which it documents the story, as well as for its broad perspective. Its purpose is to reflect on the abuse of trust that Enron illustrated, on the failure of responsibility by FERC, and on the implications of their behavior for confidence in the market and its overseers. That confidence has been shaken, Weaver argues, with lasting costs to society and making the prospects for electricity market reform very uncertain.

That said, there are some matters on which one might take issue with Weaver. Most are variants of the observation that the article is not and should not be read as a fully balanced assessment of Enron. More specific points include the following:

(1) Enron may deserve more credit than Weaver gives it for its innovation. While she acknowledges this in places, many of the markets Enron created are in principle quite meritorious. Enron's gas contracting mechanism, its online trading system, even its weather futures, can reduce the transaction costs of markets, allocate risk efficiently, and provide methods for all economic agents to deal better with uncertainty. NYMEX's development of gas futures instruments attests to the fact that some of Enron's innovations tapped clear market needs, which more traditional players belatedly discovered and sought to emulate. Whether society could have had these innovations without Enron's corrupt use of them is not addressed in this article.

(2) Weaver implicitly raises the question of whether a company like Enron was and is virtually inevitable to emerge in certain markets, with devastating effects. Where markets are inherently complex, legal and regulatory oversight is difficult, making such markets vulnerable to exploitation by corrupt agents. But if such conduct is inevitable, she implies, then creating markets with such vulnerabilities is itself bad policy. This assessment may be unduly pessimistic, in that it does not allow for improvements in regulatory design or oversight process that arguably might make such behavior more difficult or for liability assessments in the Enron matter that might deter such behavior in the future. While none of those reforms are certain, there is some history to suggest that progress on these various fronts can be made.

(3) Weaver's assessment that "in electricity, markets have met their match"[98] may be too sweeping. She bases this conclusion on the following: electricity cannot be stored, incumbents have market power, and real-time power markets are complex. But some of these features are by no means unique to electricity markets and do not prevent satisfactory operation of other markets with those characteristics. At most, it would seem that the need for real-time balance may be unique to electricity, but even that by itself may not be the cause of problems. It is in conjunction with low demand elasticity and short-run capacity constraints that the need for real-time balance creates the opportunity for strategic withholding or market exploitation. Even in electricity, some have recently proposed institutional designs and methods for addressing this problem,[99] but Weaver does not really address these more constructive matters in her discussion.

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[98] Weaver Study, p. 27.

[99] Frank Wolak, "Diagnosing the California Electricity Crisis," *The Electricity Journal,* 2003.

(4) The most arresting–and perhaps the most controversial--proposition advanced in this article is that deregulation of electricity markets might not pass the relevant cost-benefit test. Even if true, of course, it may not be entirely clear what is to be done since a vast and largely irreversible restructuring of electricity markets has taken place in most states. But Weaver's point may nonetheless merit consideration. The article contends that a fair assessment would take into account the enormous costs of California's debacle and the exploitation of electricity markets by Enron and other traders, in which case (she argues) restructuring would have to be even more enormously beneficial elsewhere to pass the test. This may be an appropriate retrospective standard, but if one wishes to assess the merits of further change, this criterion may be too broad. To assess the likely costs and benefits of further change, the only relevant aspects of the California and Enron experiences are those that can recur. To the extent that laws, regulations, regulators, and market design have since improved to the point that they can prevent the same problems, those no longer pose risks for future reforms.

In summary, the Weaver article offers a careful recounting of the Enron story and a provocative analysis of its meaning for restructuring. It does not, however, purport to be a balanced overall assessment of electricity restructuring or of its various players.

B. "The Value of Independent Regional Grid Operators," ISO/RTO Council, 2005 (ISO/RTO Council Study)

(1) SUMMARY

The ISO/RTO Council represents the seven independent system operators (ISOs) and regional transmission organizations (RTOs) in the United States, that collectively cover nearly two-thirds of electricity delivered and consumers served. In 2005, the council released a study intended to explain the major functions of ISOs and RTOs and the benefits associated with their operation. The perspective of this report is evident from the titles of its primary chapters: ISOs/RTOs Maintain and Improve Grid Reliability, ISOs/RTOs Improve Operating Efficiencies, ISOs/RTOs Operate Markets that Lower Customer Energy Costs, ISOs/RTOs Provide Fair, Independent, and Open Markets and Transmission Access, ISOs/RTOs Provide Effective Regional Planning, and RTO Costs Flatten with Size and Experience. The body of the report is devoted to advocacy of these positions.

This report does not involve any new study or data or information. Rather, it assembles data and information in support of the positions enumerated above. This support comes from the ISOs and RTOs themselves, FERC, the Edison Electric Institute, electric generation companies, as well as several of the studies reviewed in the present document.

The first substantive chapter in the report describes how ISOs and RTOs maintain and improve grid reliability. While utilities and smaller grid management organizations perform the same functions, ISOs and RTOs are said to have the size, scope, scale, tools, information and authority to be more effective. Their large sizes enable ISOs and RTOs to fund and maintain sophisticated information technology tools. Greater coordination and sharing agreements among different ISOs and RTOs is possible because of their small numbers. In addition, ISO/RTOs have invested significantly in training highly skilled operators and support staff. All these

factors are asserted to have increased grid reliability.

Next, the report argues that ISOs and RTOs realize a variety of operating efficiencies, which arise partly from optimization of resource use through centralized grid operation over larger areas. For example, electric generation reserves are more efficiently shared in large regions, and large regional grid operators can better manage the effects of simultaneous outages. Operating efficiencies have also improved because of the elimination of pancaked rates, which has made it easier for buyers and sellers to obtain transmission services over long distances. All of the above cause an increase in energy flows among regions.

The report asserts that ISOs and RTOs have facilitated the development of wholesale competition, resulting in lower wholesale electricity prices and increases in efficiency. In support of this assertion, the council report quotes the GED study's statement that "The skill of experienced fleet operators, the standardization of procedures and maintenance, and the combined buying power for fuel, equipment, and supplies have produced dramatic improvements in capacity factors and plant performance"–a proposition we have previously noted was not established by any evidence in the GED study. The council report also refers to New England ISO data indicating a 5.6% decrease in system wide weighted-average heat rate since 2000 and an increase in the percentage of time that generation units are available for dispatch from 81 to 88 percent from 2000 to 2004. And finally, it cites a TXU Energy presentation as the evidence for the proposition that incremental heat rates within ERCOT fell by 40 percent, lowering marginal price bids and saving customers more than $10 billion.

The council report next argues that ISO/RTO operations reduce retail customer electricity costs. In support of this proposition, it cites studies of the price effects of wholesale competition done by individual ISOs, as well as those by GED and CERA, discussed earlier in this review. Furthermore, the council report concludes that price and other key system parameters are more transparent within ISOs/RTOs, and that organized markets have higher liquidity, offer many mechanisms of risk management, and use locational marginal pricing or zonal pricing to manage congestion. It also notes that load-serving entities in the region can use financial transmission rights to manage congestion costs, and asserts that each ISO or RTO protects against the exercise of market power through its market monitoring function.

Next, the authors argue that ISOs and RTOs provide fair and open markets and transmission access, and also that they provide effective regional planning. The report points out that ISOs and RTOs were initially formed to meet precisely those requirements that FERC stipulated in Orders 888 and 2000. They do so by ensuring equal access to the grid, by facilitating greater competition between power suppliers, and by allowing all parties to spread their risks and lower their costs. ISOs and RTOs are also claimed to provide effective and efficient regional transmission planning since they oversee the needs of all of the utilities and loads within their areas. According to the report, a significant amount of new transmission has been built as a result of regional planning by ISOs/RTOs.

The final substantive part of the council report addresses the issue of the costs of participating in ISOs and RTOs. It begins with the assertion that each ISO/RTO has relatively fixed operating costs due to specialized information technology tools and a skilled labor force. It

offers figures suggesting that the growth in total ISO/RTO costs has slowed and that the cost per customer had flattened or even fallen over time. The report notes that where costs have grown, this reflects the expansion of ISO/RTO functions. It concedes ISO/RTO costs of $1.1 billion, but argues these are small compared to the retail customers' electricity bills and that "the value of these services and the savings and efficiencies they bring ...far exceeds the funds...spent to provide these services."[100]

(2) COMMENTARY

The ISO/RTO Council report is not so much a study as it is an advocacy piece for the merits of large regional RTOs. It offers up declarations about issues without any real evidence, conclusions from other studies regardless of their merit, and quick dismissals of some major concerns about RTOs. Its specific limitations include the following:

(1) The basic methodology of this report is flawed. It largely consists of an enumeration of the tasks of a well-functioning grid operation and then assertions that RTOs perform these better than other mechanisms. Often that is the full extent of the argument, although in a few instances, a favorable trend or comparison between points in time in a performance outcome is noted. But even where those are offered, the trends or comparisons are never tested against other possible explanations. RTOs are simply credited with every positive development in electricity markets in their regions in recent years. The lack of demonstrated causation represents poor methodology.

(2) In many places the council report cites other studies in support of its conclusions, but its reliance on studies like those by CERA, ESAI, and GED is altogether uncritical. As discussed above, those studies' methodologies are subject to serious reservations and their conclusions are often unreliable. The council report nonetheless repeats their conclusions without reservation, in some instances without even noting limitations in the methodologies that the studies themselves acknowledge. Similarly, the basis for its assertion that RTO benefits "far exceed" their costs appears to be its reference to an "analysis performed by ISO-NE [that] reveals the cost-benefit ratio to be 1:7."[101] No citation is offered for this unlikely proposition.

(3) The report dismisses much too quickly some of the more serious concerns that have been expressed about RTO operation. One of these is market power, which is addressed in exactly three paragraphs in this report. Those paragraphs are dedicated to the proposition that RTOs are superior to traditional systems because RTOs have market monitors to "protect against the exercise of market power."[102] While RTOs do indeed have market monitors, they have demonstrably failed to protect ISO and RTO markets in California and elsewhere. A large literature–none of it even mentioned in the Council report–makes clear that there are many continuing concerns over market power.

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[100] ISO/RTO Council Study p. 42.

[101] ISO/RTO Council Study, p. 43.

[102] ISO/RTO Council Study, p. 29.

(4) Further matters of growing concern are the burgeoning costs of RTOs as well as their governance and their effectiveness. The council report strives to put the cost matter to rest by asserting that costs rise only as additional functions are added to RTOs, and that costs are flattening out anyway. But many others view this matter differently. As will be discussed in the next chapter, RTO costs have become very substantial and are continuing to increase. The governance of RTOs is quite controversial and in the view of many, quite possibly dysfunctional. Their performance with respect to congestion management and infrastructure expansion is unsatisfactory to many. Scarcely any of these important issues are even mentioned in the ISO/RTO Council report.

In summary, the ISO/RTO Council report is basically an advocacy piece for RTOs. It paints a uniformly favorable picture of them, cobbled together from all suitable sources while downplaying contrary evidence, causation, and other problematic issues.

C. "Staff Report on the State of Competitive Energy Markets: Progress to Date and Future Opportunities, " New York State Department of Public Service, 2006 (NYDPS Study)

(1) SUMMARY

In early 2006, the staff of the New York State Department of Public Service issued its report on energy markets in that state. The purpose of the report was to provide an overview of the state of wholesale and retail electric and gas markets in New York, including progress in creating competitive markets and the remaining problems (referred to as "challenges" in the report) facing the state Public Service Commission and the New York ISO.

The report has two broad sections–one on wholesale electric markets, the other on retail electric and gas markets–followed by shorter sections addressing policy issues and remaining market problems. Progress in wholesale competition is measured by changes in electricity prices, the degree of robustness of markets, construction of new facilities, demand-side response, and generators' performance. The report states that between 1996 and 2004 the real price of electricity, which includes charges for supply and delivery, decreased by approximately 15.9%, 17.7%, and 14.7% for retail residential, commercial, and industrial customers, respectively. At the wholesale level, after adjustment for changes in fuels costs, the average price has been constant for the last several years.

The report next examines the remaining measures of wholesale market development, described in the above paragraph. Volatility in prices in the NYISO's day ahead energy market declined from 2000 to 2004, although it increased again in 2005. With respect to market robustness, the report concludes that NYISO's spot and short-term markets for energy and capacity are generally quite liquid, while longer-term forward energy and capacity markets are not. New facilities construction is reported to be substantial and said to be helpful in ensuring market performance. In addition, seams between control areas have been reduced, resulting in more entry by suppliers from adjacent areas into the New York market. And finally, the Report presents data indicating that summer availability of generators increased from 86.5 percent before formation of the NYISO to 90.3 percent in recent years.

The second half of the wholesale market section of the report is devoted to a series of wholesale market design issues, including market rules, price transparency, system reliability, market power, capacity markets, demand-side response, and regional markets. The authors note, for example, that price transparency is important since efficient electricity markets depend on prices accurately reflecting the cost of supply. Also, generation costs vary significantly between different locations on the electric grid, something reflected in NYISO wholesale market price data. With respect to system reliability, tight coordination of wholesale generation is achieved by central dispatch and has been facilitated by the entry of new and efficient generating units. In addition, NYISO uses an annual comprehensive reliability planning process to predict system reliability needs over a longer ten-year period.

As for market power, the report provides the Herfindahl-Hirschman Index (HHI), a measure of market concentration.[103] The HHI for the state, not including New York City and Long Island, is 1028, indicating a low potential for market power. For the New York City metropolitan area and Long Island, the HHIs are 1843 and 6317, respectively, indicating considerable potential for market power. The report states that mitigation should be continued to ensure that prices remain at competitive levels.

Regarding capacity markets, the Department notes that flaws in the original design of the capacity market in New York caused it to be replaced in 2003 with a new system which, it is claimed, results in procuring excess capacity at a lower price. As for demand response, the NYISO has implemented a number of voluntary price-responsive load and distributed generation programs that give customers an opportunity to make decisions on whether to curtail load, by how much, and to be compensated for these actions accordingly. Regarding regional markets, the report mentions that since 2000 the NYISO has been cooperating with PJM, IESO (Ontario), and ISO-NE to facilitate interregional trade.

The next major section of the report is devoted to electric and natural gas retail markets. It describes the development of retail markets, progress in retail energy markets, and education and outreach. It notes, for example, that there are at least seven competitive suppliers serving residential electric customers in each major utility franchise area in the state. Progress in retail energy markets is measured by a variety of factors, both on the supply and customer sides. It cites much data and concludes by referencing Joskow's study indicating that while the average real price for residential customers in states without retail electric competition fell by about 8%, the real residential electric price in New York fell by about 14%. As for the level of customer satisfaction, the report notes a decline in the number of customer contacts regarding the services provided by non-utility suppliers, as well as increases in both the number of customers served by these competitive suppliers and in the extent of migration from the utilities.

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[103] The HHI index of concentration is defined as the sum of squared market shares of all sellers. It ranges from 0 for a perfectly competitive industry, to 10,000 for a monopoly. The Department of Justice/Federal Trade Commission Merger Guidelines term an industry with an HHI in excess of 1000 as moderately concentrated, and one with an HHI or 1800 or more as highly concentrated, although actual antitrust practice involves higher thresholds.

The report follows up on all this information by discussing policy issues and remaining problems. According to the report, regulatory intervention is still needed to promote renewable energy resources and demand-side management. Finally, the report notes remaining issues regarding demand side response, regional markets, wholesale market rules, new generation and transmission, customer awareness and education, price signals and value-added services, infrastructure and retail market design.

(2) COMMENTARY

The New York Department of Public Service staff report is more a progress report on restructuring than it is an evaluation. It begins by declaring that "New York State is recognized as a leader in this area"[104] and then recounts the many beneficial changes that have occurred under the "vision" of the Department of Public Service and since the formation of the New York ISO in 1999. Even as a progress report, however, it has a number of limitations.

(1) This report fails to address questions of causation carefully, sometimes not at all. The authors substitute simple declarations and speculations for analysis to connect many observed changes in electricity prices to restructuring or other policy actions. The mere fact that such changes may have coincided with new policies and institutions is taken as confirmation that these policies are responsible for those changes. Sometimes this approach requires further leaps, as with the assertion that "volatility of energy prices in the NYISO's Day Ahead Energy Market decreased between 2000 and 2004, reflecting maturity in the market."[105] But the very next sentence observes that volatility subsequently *increased* in 2005, for which the report offers entirely ad hoc explanations (possibly accurate, but unsupported). Many of the central arguments of the report are similarly unproven assertion.

(2) The Report glosses over facts that do not fit neatly in its overall story of the benefits of restructuring. Notable is its mention of the fact that despite all the changes in the wholesale markets, the average price of power in New York state outside of New York City was essentially the same in 2002-04 as it was prior to restructuring in 1997. Oddly, the report does not provide this same important price comparison for New York City or alternatively for all of New York state. In addition, the report makes the claim of lower post-restructuring prices in real terms, but it fails to acknowledge the temporary downward price effect of retail price reduction-and-freeze programs and of excess capacity.

(3) The report's discussion of market power concerns seems uncertain about what to conclude. It first notes the high concentration measures in certain areas of the state, notably, Long Island, and the implications of such concentration for market power. Yet the report cites the finding of the NYISO's "independent market advisor" that the NYISO electric market is competitive, with no evidence of significant economic or physical withholding.[106] Neither of

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[104] NYDPS Study, p. 1.

[105] NYDPS Study, p. 12.

[106] Withholding occurs when a generator shuts down one or more of its units in order to

these seem adequate to assess market power separately: Concentration measures are just one factor, albeit an important one, in the assessment of market power. And withholding is only one dimension of market power, and an elusive one at that.

(4) In places the report offers data that exaggerate its point. Seeking to emphasize the extent of retail competition, for example, it asserts that "The opening of retail energy markets to competition has provided all New York state consumers–9.4 million residential and 1.2 million business electric and natural gas accounts–with the ability to choose their commodity supplier."[107] Elsewhere it notes that there are 73 suppliers in New York. Reading on, one discovers that this figure includes non-electricity providers and in any case represents the entire state rather than those areas where consumers have the ability to choose. The upshot is that a fairly modest 6.7 percent of residential accounts in the state receive electric service from an independent supplier.

In summary, the intention of this staff report of the New York State Department of Public Service seems not to be a careful or balanced assessment of the issues. Rather, it is at best an update on changes in the electricity (and gas) markets in New York and in state policies affecting these markets. Even as an update, however, it pays inadequate attention to causation and precision in its evidence and claims.

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increase the price received for the remaining generation (physical), or alternatively bids so high as to prevent the unit's dispatch (economic).

[107] NYDPS Study, p. 28.

VI. OTHER ISSUES IN ELECTRICITY RESTRUCTURING

The preceding chapters have reviewed 12 studies of electricity restructuring. Most of the comments have been directed at the manner in which the studies handle various methodological issues in comparing performance under restructuring to prior conditions. In addition to how well these studies answer the questions they *do* ask, it is also important to recognize some relevant questions that they generally do *not* address. Among the latter are several important costs and risks associated with restructuring. Since such costs and risks are an integral part of the reform process, these should be examined with the same attention as any benefits in the overall assessment of restructuring, but are not.

This chapter briefly addresses three matters that receive little or no attention in most of the studies reviewed herein. These subjects are market structure, market power, and mergers; RTO costs, governance, and effectiveness; and service quality and reliability. Some exceptions to this general lack of attention should be noted. The article by Weaver is largely devoted to the issue of market manipulation, although that problem is not discussed in any of the other studies. Market power is noted in the CAEM and in the NY DPS studies , but without much analysis. Concerns over RTO costs are raised–and then dismissed--in the ISO/RTO Council study. Broadly speaking, the attention received by these issues falls well short of their importance.

A. Market Structure, Market Power, and Mergers

Restructuring the electric power sector has altered some traditional and perhaps useful features of the industry. At the same time it has unleashed a wave of mergers and questionable practices. Some of these changes are serious enough to raise a very real question about the prospects for competition in electricity markets. Few of these issues receive much attention in these studies. Here we shall briefly review such concerns in four related areas:

•*Vertical market structure.* Economic studies have shown that the traditional vertical integration of utilities serves to capture substantial efficiencies of coordination among the generation, transmission, and distribution stages of production.[108] Although viewed as necessary to allow for even-handed competition among generators, de-integration has proven to be a costly undertaking. ISOs and RTOs were intended to be alternative means of securing those efficiencies but their record is decidedly mixed. The difficulties associated with this situation are underscored by the fact that those states that initially did not de-integrate their utilities now adamantly refuse to do so. Also, interestingly, many de-integrated utilities have sought to reintegrate by acquiring or building their own generation plant, further suggesting that this aspect of restructuring has imposed significant costs.

•*Market power in wholesale power markets*. Concern over market power is underscored by studies both of concentration in generation markets and of prices in various regions. FERC's *2004 State of the Markets Report* finds that the largest 10 generation companies now account for

[108] "Vertical Economies in Electric Power: Evidence on Integration and Its Alternatives," John Kwoka, *International Journal of Industrial Organization*, 2002.

anywhere from 74 to 83 percent of generation in all regional markets but California and the Midwest.[109] Moreover, an increasing proportion of generation in these regional markets has been acquired by a small number of national generation companies.[110] Rising concentration is paradoxical, since fostering competition in generation was the central purpose of restructuring. With such competition in jeopardy, the very promise of restructuring lies in doubt.

As for performance, various studies have documented a persistent gap between prices and marginal costs–a standard measure of market power--in many regional markets, including where RTOs exist. These include research by Mansur, who finds the PJM market in its first year caused overcharges of $224 million, extrapolated to $827 million since bilateral contracts follow the same differential[111]; by Bushnell and Saravia, who calculate a persistent monopoly markup in the restructured New England market of 4 to15 percent[112]; by Borenstein, Bushnell, and Wolak, who conclude that 59 percent of the $7 billion increase in California's power costs in the summer of 1999 was due to market power[113]; and by Tucker, who estimates price markups averaging 14.7 percent in PJM in 1999.[114] All of these studies underscore the pervasive problem of market power in restructured electricity markets.

•*Mergers among both generation companies and among distribution utilities*. More than 70 mergers involving electric utilities occurred in the 10 years from 1994 to 2003, many of these involving distribution utilities. Over the past five years, the number of mergers has declined, although fully 6 percent of all installed generation capacity changed hands in the single year 2004.[115] What is notable about the recent experience is the enormous size of the individual transactions. For example, the Duke-Cinergy merger and the failed effort of Exelon to merge with PSEG both involved companies worth tens of billions of dollars and would create utilities with enormous geographic footprints.

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[109] FERC, *2004 State of the Markets Report*, June 2005.

[110] *Investigation of Bulk Power Markets*, FERC Staff Report, November 2000. National Transmission Grid Study, Department of Energy, May 2002.

[111] "Pricing Behavior in the Initial Summer of the Restructured PJM Wholesale Electricity Market," Erin Mansur, POWER Working Paper 083, 2001.

[112] "An Empirical Assessment of the Competitiveness of the New England Electricity Market," CSEM Working Paper 101, 2002.

[113] "Measuring Market Inefficiencies in California's Restructured Wholesale Electricity Market," Severin Borenstein, James Bushnell, and Fran Wolak, *American Economic Review*, 2002.

[114] "Measuring Market Performance in Restructured Electricity Markets: An Empirical Analysis of the PJM Energy Market," Russell Tucker, George Washington University PhD dissertation, 2002.

[115] FERC, *2004 State of the Markets Report*, p. 30.

Most of these mergers have been approved by FERC and state utility commissions on the promise of cost savings and improved efficiencies from the increase in size and improvements in the operating structure of the merged entity. But preliminary evidence from the distribution mergers that dominated the 1994-2003 period refutes the contention that better-managed utilities were seeking out poor performers for improvement and that the acquisition therefore resulted in efficiency gains to the acquired company.[116] If anything, the reverse appears to be the case, as weak performing utilities acquired better performers, whose efficiency thereupon declined. This and other evidence gives rise to legitimate concern over the merger trend in this industry.

•*Unilateral withholding of generation capacity and other manipulative practices.* Unlike traditional concerns over competition among a few sellers, unilateral withholding does not involve cooperation or collusion. Rather, its power derives from the ability of a single owner of generation plants to shut down part of its operations and thereby to raise market price sufficiently so as to recoup more than any lost profit on the shuttered capacity from the added profit on the still operational units. For unilateral withholding to produce net profit gain requires a capacity-constrained market and very low demand elasticity. These conditions occur with some frequency in most electricity markets, and indeed characterized California throughout much of the 2000-01 crisis period.[117] Unilateral withholding is especially pernicious market behavior since it is difficult to prove and does not appear to be readily controlled by antitrust or regulation. This and other manipulative practices that characterized California's energy crisis represent matters that regulators have failed to address or prevent.

B. RTO Costs, Governance, and Effectiveness

Regional transmission organizations are novel institutions designed to incorporate and extend the best features of independent system operators, and perhaps PJM in particular. Encouraged by FERC Order 2000, a total of six RTOs have now been approved and operate over more than half of the country's electric power systems. As they have been formed and evolved, however, a number of concerns have arisen. Here we briefly review three that should be recognized in any overall assessment of RTOs or electricity market structure in general:

•RTO costs have grown and continue to increase to a worrisome degree. FERC itself has estimated that a single best-practice RTO with day-one capability costs between $38 and $117

[116] "Deregulation, Mergers, and Efficiency: Evidence from the U.S. Electric Power Industry," John Kwoka and Michael Pollitt, Northeastern University and Cambridge University, working paper, 2006.

[117] For formal analyses, see "Unilateral Withholding: Market Power and California's Electricity Crisis," John Kwoka, George Washington University Working Paper, May 2001; "A Quantitative Analysis of Pricing Behavior in California's Electricity Market During Summer 2000," Paul Joskow and Edward Kahn, *Energy Journal*, 2002; and "Measuring Unilateral Market Power in Wholesale Electricity Markets: The California Market, 1998-2000," Frank Wolak, *American Economic Review*, 2003.

million to establish and $35 to $78 million each year to operate.[118] A day-two market will require up to $250 million in investment costs and nearly the same amount in annual operating costs.[119] Aggregating these costs to all six ISOs, Lutzenshiser calculates the annual total to be on the order of $1 billion in 2004. Extrapolating to the entire national electricity market, she concludes that the annual costs of RTOs will be $2.5 billion, which, interestingly, equals FERC's own estimate of the likely total benefits of RTOs.[120] These figures represent an annualized rate of growth of 20 percent, a doubling since 2001, and for some individual ISOs a tenfold increase during that time.[121]

•RTO governance has raised further concerns. Governance varies among the individual RTOs, but involves an independent board of various stakeholders. Apart from board members' sometimes divergent objectives, its very task is something of an oddity–the nonprofit operation of assets that it does not own. As one observer has noted, it is difficult to see how such an ownership and governance structure would produce the desired outcome: "These independent entities own no transmission assets, have no linemen or helicopters to maintain transmission lines and respond to outages, and are not directly responsible for the costs of operating, investing in, or the ultimate performance of the transmission networks they "manage."[122] Such concerns have led one group of interested parties to plead for the FERC to "view RTOs for what they are–regional monopolies that it must vigorously regulate, not regional extensions of the Commission itself."[123]

•RTO effectiveness is much in dispute. It is widely understood that RTOs have encountered major difficulties in resolving transmission congestion and have largely failed to encourage transmission investment. The PJM *2005 State of the Market Report*, for example, noted that "congestion costs have ranged from 6 to 10 percent of total PJM annual billings since 2000. Congestion costs were approximately 9 percent of total PJM billings for 2005, as they

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[118] *Staff Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization*, FERC, October 2004.

[119] A "day one" RTO administers the real-time energy market and manages congestion, while a "day two" RTO offers full markets for day-ahead and real-time capacity, energy, ancillary services, and market-based congestion pricing.

[120] Order 2000, FERC, pp. 95-96. The benefits anticipated by FERC were based on studies of the effects of dispatch over a wider area, on the assumption that offer prices were at marginal cost. This has not proven generally to be the case.

[121] "An Expensive Experiment? RTO Dollars and Sense," Margot Lutzenhiser, *Public Utilities Fortnightly*, December 2004.

[122] "Transmission Policy in the United States," Paul Joskow, MIT Working Paper, October 2004, p. 30.

[123] *Restructuring at the Crossroads,* American Public Power Association, 2004, p. 17.

were for 2004. Total congestion costs were $2.09 billion in calendar year 2005..."[124] A 2004 report by the Transmission Access Policy Study Group cited several sources indicating widespread congestion costs running in the hundreds of millions of dollars regionally.[125]

Despite these substantial congestion charges, transmission congestion is a serious and growing problem. Nationally, transmission line loading relief actions were reported to be four to five times more numerous in 2000 and 2001 compared to earlier years.[126] In the longer term, RTOs have proven largely ineffective in new transmission planning and development.[127] Faced with these issues, FERC itself has recently encouraged examination of alternatives to RTOs–for example, companies that jointly own and share investment in transmission, called "transcos"–in a further effort to address this problem.

C. Service Quality and Reliability.

One neglected issue in these evaluations of restructuring is any possible effect on service reliability and quality. Such effects would not be surprising, as restructuring has fundamentally altered both the structure of the industry and the incentives facing its participants. The traditional vertically integrated utility's "obligation to serve" has been replaced by contractual arrangements between generators and distribution utilities. Information and coordination links between generators and distributors have been severed. Profit incentives have been strengthened in the hope of achieving efficiencies, but without equal attention to reliability and quality of service.

This altered structure and incentives indisputably can affect outcomes, as is evidenced by documented examples of strategic withholding of capacity, discussed above, and by studies of the quality effects of incentive regulation in electricity and other markets.[128] Here we review some evidence not mentioned in the 12 studies reviewed in this paper, evidence that directly addresses the relationship between electricity restructuring and reliability.

•The Interim Report of DOE's Power Outage Study Team investigated eight significant system outages and disturbances that occurred during the summer of 1999. While many traditional causes of outages were found partly responsible, the findings of the study team also faulted deregulation in the following terms:

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[124] PJM *2005 State of the Markets Report*, p. 45.

[125] "Effective Solutions for Getting Needed Transmission Built at Reasonable Cost," TAPS, June 2004, p. 5.

[126] National Transmission Grid Study, 2004, p. 12.

[127] See for example, the National Transmission Grid Study; also, TAPS.

[128] For example, see "The Effects of Incentive Regulation on Quality of Service in Electricity Markets," Anna Ter-Martirosyan, paper presented at the International Industrial Organization Conference, Boston, March 2003.

> In anticipation of competitive markets some utilities have adopted a strategy of cost cutting that involves reduced spending on reliability. In addition, responsibility for reliability management has been disaggregated to multiple institutions, with utilities, independent system operators, independent power producers, customers, and markets all playing a role. The overall effect has been that the infrastructure for reliability assurance has been considerably eroded.[129]

•In "The Frequency of Large Blackouts in the United States," Hines, Apt, and Talkundar. examine NERC Disturbance Analysis Working Group (DAWG) data up through 2005, adjusting for "extreme" natural events such as earthquakes and hurricanes as well as certain other matters.[130] Outage data are then compared for the years before and after 1998, chosen as the turning point in deregulation. A statistical test on the difference in outage frequency finds that "blackout frequency is significantly greater in the second period (1998-2003) compared to the first (1984-1997)."[131] The study speculates on, but ultimately does not test, alternative possible reasons for this trend.

•The U.S.-Canada Power System Outage Task Force investigating the August 2003 blackout concluded that restructuring was not a cause of that episode, but it did endorse further study of the concerns about its possible effects.[132] Ten papers were commissioned from a variety of technical experts and industry leaders. Three of these papers argued that restructuring bore major responsibility for decreased reliability, while three others rejected any connection. The remaining studies faulted deregulation in part or did not express a direct opinion. The most aggressively critical of these studies argues that with restructuring, industry focus has shifted from coordination to competition, and from reliability to profits; that maintenance expenditures, manpower, and technical expertise have declined in favor of financial objectives; and that the proliferation of players have vastly increased the complexity of decision-making and operations.[133] Others, however, point out that new technologies and institutions as well as larger regional markets have helped to "harmonize market participants with system reliability

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[129] Interim Report, Department of Energy Power Outage Study Team, Findings from the Summer of 1999, January 2000, p. S-1.

[130] "The Frequency of Large Blackouts in the United States," Paul Hines, Jay Apt, and Sarosh Talkunder, paper presented at the second Carnegie Mellon Conference on the Electric Power Industry, January 2006.

[131] Hines, et al, p. 8.

[132] *Report on the August 14, 2003 Blackout*, U.S.-Canada Power System Outage Task Force, June 2006, Recommendation 12: The Relationship between Competitive Power Markets and Grid Reliability, p. iii.

[133] "Contributions of the Restructuring of Electric Power Industry to the August 14, 2003, Blackout," Jack Casazza, Frank Delea, and George Loehr, Power Engineers Supporting Truth, *Report on the August 14, 2003 Blackout*.

needs."[134]

None of these studies or other evidence about service quality and reliability is definitive.[135] In short, there is good reason for concern that restructuring may have adversely affected service quality and reliability. This issue deserves further study and certainly at least some mention in studies that purport to assess restructuring comprehensively.

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[134] "Relationship between Competitive Power Markets and Grid Reliability: PJM RTO Experience," by Phillip Harris, PJM, *Report on the August 14, 2003 Blackout*.

[135] Other fragmentary evidence can be found in "Pennsylvania Utilities: How Are Customers, Workers, and Corporations Faring in the Deregulated Electricity, Gas, and Telephone Industries," Keystone Research Center, May 2001, and "Power Outages During Market Deregulation" by Gail Kendall, *IEEE Control Systems Magazine*, December 2001.

VII CONCLUDING OBSERVATIONS

The restructuring of the electric power industry has been described as "one of the largest single industrial reorganizations in the history of the world."[136] Over the past 10 to 15 years, state and federal policies have de-integrated and reorganized electric utilities, replaced administrative oversight with markets, created new institutions to coordinate the separated generation, transmission, and distribution stages, encouraged entry of new unregulated suppliers and marketers, and generally sought to unleash competitive forces. As with the deregulation and reform of other industries, electricity restructuring was intended to produce cost efficiencies and price benefits to consumers.

The 12 studies covered in this review represent perhaps the most prominent recent efforts to determine whether this consumer benefits objective has been or is being achieved.[137] Nine of the 12 find efficiency gains in wholesale markets or retail price benefits from restructuring. The nine favorable studies are those authored by the Center for the Advancement of Energy Markets, Synapse, Global Energy Decisions, Energy Security Analysis, Inc., the ISO/RTO Council, Cambridge Energy Research Associates , Joskow, Fagan, and the NY State Department of Public Service, although those by Synapse, Joskow, and Fagan substantially qualify their conclusions or methodologies. The remaining three articles–by Weaver, Apt, and Taber et al–come to unfavorable conclusions about the effects of restructuring.

The focus of this review has been on the strengths and limitations of the specific methodologies used in these studies and hence on the confidence that one should place in their conclusions. In that regard, this report has documented significant methodological deficiencies in virtually all of these studies. In some instances the deficiencies could be remedied and the results of an improved study would be of interest, but in other cases the defects are sufficiently serious as to render the exercise invalid. In addition, this report has noted several important aspects of restructuring that receive too little, if any, attention in these studies, leaving their assessment incomplete. For all these reasons we conclude that these studies consistently fall

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[136] *Electricity Restructuring–Action Needed to Address Emerging Gaps in Federal Information Collection,* General Accounting Office, June 2003, p. 1.

[137] As this review was being completed, a new study appeared. Entitled *A Review of Electricity Industry Restructuring in New England* and authored by Polestar Communications & Strategic Analysis for the New England Energy Alliance. It asserts that restructuring has saved New England electricity customers between $6.5 and $7.6 billion in the 1998-2005 period. It may be sufficient to note two of the study's own disclaimers: "This paper makes no judgment as to whether or not the formerly regulated electric utilities could have achieved the same performance level if restructuring had not taken place" (p. 1, fn. 1) and also, "It was beyond the scope of this paper to project the future sustainability of any economic savings from restructuring" (p. 1, fn. 2). Both of these matters are crucial to estimating the true incremental equilibrium effect of restructuring. Moreover, the Polestar report cites the CERA, NYDPS, and GED studies as corroborating its findings, studies we have found to be altogether unreliable.

short of the standards for good economic research, casting doubt on their conclusions.

These studies are important since they represent the first wave of evaluations of electricity restructuring up to this point in time, and also provide guidance on further possible reforms. For example, a recent "open letter" signed by several prominent economists urged policymakers to "stay the course" and to pursue further electricity deregulation, asserting that "there is growing evidence and convincing studies that show that consumers have saved billions of dollars in energy costs as a result of competitive markets..."[138] But as this review has shown, existing studies do not support that proposition. Indeed, they show that there is no credible and convincing economic evidence that consumers have been made better off by electricity restructuring. The unsupported conclusions of these studies should not serve as the basis for further ill-defined "deregulation" or "competition" solutions to the present difficulties in electricity markets.

Three additional observations conclude this report. First, it should be noted that this report has not surveyed all studies and evidence that bear on the effects of electricity restructuring. For example, some studies have found efficiency gains in divested generation plants, although others respond with evidence that stronger incentives rather than divestiture may be responsible.[139] Such other studies constitute a broader literature related to restructuring, but this has not been surveyed in this report. To that extent, more is known–at least in piecemeal fashion--about electricity restructuring than is contained within these studies and hence in this report.

A second observation concerns the origin of these studies. Five of the 12 studies reviewed here are consulting reports. Another five are authored by academics, with the remaining two being internal evaluations by affected agencies. It is therefore interesting to note that the nine favorable assessments of restructuring include all five consulting reports as well as both internal assessments. Three of the five academic studies, by contrast, offer negative overall assessments, with the remaining two favoring restructuring. If the latter unsponsored studies can be viewed as more independent of interested parties, then one might conclude that independent

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[138] "Open Letter to Policymakers," Compete Coalition, Washington, D.C., June 26, 2006. The only specific piece of evidence cited is the comment that "[o]ne estimate found that performance improvements from divested power plants produced enough additional energy to power more than 25 million households in the Eastern interconnect for a year." That precise figure–25 million additional households–can be found in the Global Energy Decisions study, (*Putting Competitive Power Markets to the Test*, p. RS-1) but as documented in this review, the methodology of that study is fundamentally flawed and its conclusions should be given no credence.

[139] See "Does Competition Reduce Costs? Assessing the Impact of Regulatory Restructuring on U.S. Electric Generating Efficiency," Kira Markiewicz, Nancy Rose, and Catherine Wolfram, NBER Working Paper 11011, 2004. Also, "Ownership Change, Incentives, and Plant Efficiency: The Divestiture of U.S. Electric Generating Plants," James Bushnell and Catherine Wolfram, CSEM Working Paper 140, 2005.

views of restructuring are considerably more evenly split than the overall number of studies might suggest.

Finally, we note that despite the voluminous criticism of these 12 studies in this report, a sound study is by no means impossible. A number of these studies have deficiencies that are quite correctable. Issues that compromise one study may be found adequately addressed in another. For example, stranded cost issues or the choice of benchmark states are problematic in some studies, but others do a satisfactory job in dealing with them. Matters like excess capacity are more difficult, but a study of the price impact of excess capacity could be undertaken. Alternatively, an analysis of the sensitivity of overall results to a range of possible effects from capacity would be informative and perhaps sufficient. A study that takes these and other issues fully into account is entirely feasible.

In summary, the 12 studies reviewed here represent the most prominent, comprehensive, and often-cited assessments of the effects of electricity restructuring. After close analysis of these studies, however, this report finds that their methodologies contain numerous deficiencies that undermine confidence in their conclusions. In particular, despite much advocacy to the contrary, there is no convincing evidence that consumers are better off as a result of electricity restructuring

It may be hoped that this report will have two effects, one cautionary, the other constructive. The caution concerns the debate about electricity restructuring to date and in the future. To the extent that the debate looks to these studies for conclusions about past policy or for insights regarding future policy directions, it should be recognized that these studies do not constitute a reliable foundation for those purposes. More constructively, the critiques of these studies suggest improved methods for further study of electricity restructuring. By remedying the deficiencies of existing studies, future studies may be methodologically more sound and substantively more convincing, in which case they will serve as better guides to policy initiatives in this most important industry.

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