ERECTING SANDCASTLES FROM NUMBERS: THE CAEM STUDY OF
RESTRUCTURING ELECTRICITY MARKETS
OR
A CRITIQUE OF
“ESTIMATING THE BENEFITS OF RESTRUCTURING ELECTRICITY MARKETS:
AN APPLICATION TO THE PJM REGION”

Prepared for
National Rural Electric Cooperative Association

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ABSTRACT

The National Rural Electric Cooperative Association commissioned Christensen Associates to review and critique the Center for Advancement of Energy Markets’ (CAEM’s) study entitled “Estimating the Benefits of Restructuring Electricity Markets: An Application to the PJM Region” (hereafter referred to as the “Study”), dated September 22, 2003. This Study begins with the claim that it “estimates the benefits of restructuring the electricity market in the PJM region.” On the contrary, we find that severe weaknesses in the Study’s methodology imply that its estimates are largely worthless to policymakers interested in the potential benefits of restructuring wholesale and retail electricity markets.

The Study includes among the benefits of restructuring the price effects of everything that happened in PJM during 1997-2002, including things that had little or nothing to do with restructuring. Furthermore, the Study presumes that the relative price changes from 1997-2002 represent a permanent benefit that extends into the far future. This is highly questionable. The 15% rate increases in New Jersey in 2003 provide a good example of a completely opposite outcome. At the end of the 4-year transition period in August 2003 the utilities’ rates were increased to recover the costs of purchasing power at rising wholesale prices above the artificially depressed retail rates. Thus, all of the effects of fluctuating circumstances during 1997-2002 are included in the Study’s estimates of benefits that are assumed to continue into the indefinite future.

In conclusion, the CAEM Study represents a seriously flawed analysis of the economic effects of restructuring in the wholesale and retail electricity markets in the PJM region. The Study has not provided any evidence that the reductions in the retail prices in the PJM states from 1997 to 2002 were the result of any efficiency gains that came about through restructuring either the wholesale or retail markets.

The Study cannot be relied upon to infer what, if anything, about the restructuring in the retail and wholesale markets in the PJM region is good or bad; no causal hypothesis has been constructed or tested in this analysis. Policy and decision makers must be presented with evidence about what it costs to make the kinds of changes that have been made in the PJM wholesale markets and the changes that have occurred in the state retail markets, and what the cost savings are that result from these reforms. A useful study would enable policymakers to compare the costs and the savings. While the CAEM Study recommends that the PJM model be emulated in other parts of the country, it does not provide any insights into what it would cost to emulate that model, nor in fact what model has been applied in the PJM region, or what parts of the model are good and what parts should be rethought. The CAEM Study fails to provide policymakers with the kind of information that is absolutely essential for discerning whether restructuring at the wholesale or retail levels makes sense in other parts of the country.

1 Study at page 4.
EXECUTIVE SUMMARY

The National Rural Electric Cooperative Association commissioned Christensen Associates to review and critique the Center for Advancement of Energy Markets’ (CAEM’s) study entitled ‘Estimating the Benefits of Restructuring Electricity Markets: An Application to the PJM Region’ (hereafter referred to as the ‘Study’), dated September 22, 2003. This Study begins with the claim that it “estimates the benefits of restructuring the electricity market in the PJM region.” On the contrary, we find that severe weaknesses in the Study’s methodology imply that its estimates are largely worthless to policymakers interested in the potential benefits of restructuring wholesale and retail electricity markets.

The Study’s core finding is that the present discounted value of future savings to ultimate customers in the PJM region from “current restructuring efforts” will be about $28.7 billion. This finding relies upon a seriously flawed quantitative analysis. The study’s $28.7 billion “benefit” is comprised of the following two components.

The first component—$20.1 billion—is derived by comparing retail electricity price changes in PJM during the period 1997-2002 to retail price changes in neighboring states and the U.S. average during that same period. Although the Study repeatedly acknowledges that the relatively large drop in PJM’s retail prices may have been due to factors other than restructuring, the quantitative analysis nonetheless claims 100% of this relative price drop was due to restructuring. By the Study’s own repeated admission, it fails to determine the extent to which these price trends are due to PJM’s restructuring as opposed to other factors. It may be the case that, among the many causes of the relatively large fall in PJM prices during 1997-2002, restructuring had a negligible role. It is surely the case that the fluctuations in retail rates that occur over a 5-year historical period provide an insufficient basis for the Study’s long-term projections of benefits.

The second component—$8.6 billion—is what the Study calls a “post stranded cost recovery” benefit. This represents the savings that customers will supposedly enjoy when the completion of PJM utilities’ stranded cost recovery causes PJM prices to decline in year 2009. Contrary to the Study’s claims, however, this $8.6 billion ‘benefit’ is not due to restructuring but is merely due to the expiration of the amortization of past sunk costs. When these past sunk costs are fully amortized, retail prices in PJM will indeed fall; but that will happen regardless of restructuring. This is an example of the Study attributing benefits to restructuring that are due to entirely unrelated causes.

The Study provides no legitimate quantitative support for its major conclusion that “The benefits to consumers from restructuring efforts, particularly in the wholesale electricity market, in the PJM region are substantial.” Instead, the Study’s quantitative analysis merely finds that prices

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2 Study at page 4.
3 See, for example, the Study at page 4. The Study presents benefits as $28.524 billion in the table on page 5 (rounded to $28.5 billion on page 4) and as $28.656 billion on page 47. In our discussion, we use the $28.656 billion figure (rounded to $28.7 billion).
4 Study at page 4.
in the high-cost PJM region fell by more than did the prices of some of its low-cost neighbors during a recent 5-year period, and that they will fall in the future when certain stranded costs are fully amortized. The Study’s quantitative results fail to demonstrate any relationship between these price changes and the economic effects of restructuring.

The vast majority of the nominal price changes from 1997 to 2002 in these states probably stem from mandated retail rate reductions. For example, in Delaware, nominal average residential revenues declined by 6.33% between 1997 and 2002, and the average mandated rate reductions were 6.3%. In Maryland, nominal average residential revenues declined by 8.3% while mandated rate reductions averaged about 6.9%, which provides an explanation of about 83% of the change. Pennsylvania appears to be an anomaly in that mandated residential rate reductions in Pennsylvania averaged about 8%, but the nominal average residential revenues only declined about 2% during this period.

In short, the Study includes among the benefits of restructuring the price effects of everything that happened in PJM during 1997-2002, including things that had little or nothing to do with restructuring, or if they were related to the restructuring process, they had nothing to do with real cost reductions or efficiency improvements. Furthermore, the Study presumes that the relative price changes from 1997-2002 represent a permanent benefit that extends into the far future. This presumption is incorrect. The experience in New Jersey illustrates why this is incorrect. New Jersey’s restructuring deal required New Jersey’s utilities to reduce their rates beginning in 1999 by an average of 10% even though these reduced rates turned out to be insufficient to allow full recovery of purchased power costs. With the end of the transition period in August 2003, these utilities were allowed to substantially raise retail rates to recover the costs that were deferred during the 4-year transition period. As this example indicates, the benefits of mandated retail rate reductions cannot be assumed to extend into the indefinite future. Thus, all of the effects of fluctuating circumstances during 1997-2002 are included in the Study’s estimates of benefits.

Furthermore, any assessment of the potential benefits of electricity market restructuring is incomplete without consideration of the costs associated with such restructuring. But the Study does not identify, quantify, or even discuss the costs of restructuring the PJM wholesale or retail markets. It acknowledges only one of the several major difficulties that are inherent in making competitive markets work efficiently, namely market power; and gives short shrift to even this one difficulty. The Study displays no awareness of the significant costs of creating and administering electricity markets, of the difficulties of jointly optimizing generation and transmission investments in a market setting, and of market participants’ costs of dealing with financial risks in a market system that are virtually absent from a regulated system. These are serious problems that have undermined the financial stability of the industry, led to major bankruptcies, and arguably reduced power industry investments. Yet these problems are absent from the world that the Study describes.

To conduct a proper benefit-cost analysis of restructuring, it is necessary to identify the most significant changes that arise from the restructuring, and then measure the changes in costs and benefits associated with those changes. Both benefit changes and cost changes need to be counted once and only once. The focus of the assessment analysis should be on economic efficiency impacts. These impacts are composed of two parts—1) changes in operational efficiencies that reduce costs on net in the wholesale market (i.e., changes in the cost of production and delivery of electricity, after accounting for the costs of creating new markets and
institutions, such as RTOs), and 2) changes in net benefits to consumers in general from retail price reductions that flow from the lower wholesale costs. These measures of efficiency impacts serve as a gauge of the change in society’s overall net benefits.

However, it is also reasonable for a study of restructuring’s benefits to be cognizant of the distributional impacts of restructuring. Distributional impacts represent offsetting changes in the bills of particular groups of consumers or the revenues to particular generation firms. In virtually all industry restructuring efforts, in the short run, some groups will benefit more than others, with some groups possibly being made worse off in the short run. For example, in the short run, restructuring of the wholesale market may mean that end-use customers in one state may initially pay higher prices than before the change while end-use customers in another state may pay lower prices than before. Furthermore, the retail electricity price level in any state, even when it is regulated, is a function of many factors, some related to restructuring and others that would change and affect the retail price regardless of restructuring at the wholesale or retail levels. Therefore, it is also vital to isolate the economic effects that are solely attributable to restructuring.

In conclusion, the CAEM Study represents a seriously flawed analysis of the economic effects of restructuring in the wholesale and retail electricity markets in the PJM region. The Study has not provided any evidence that the reductions in the retail prices in the PJM states from 1997 to 2002 were the result of any efficiency gains that came about through restructuring those markets, and it has ignored the evidence that the price reductions were due to other causes.

The Study cannot be relied upon to identify the elements of restructuring in the wholesale and retail markets in the PJM region that are beneficial or to infer what, if anything, about the restructuring in the retail and wholesale markets in the PJM region is good or bad; no causal hypothesis has been constructed or tested in this analysis. Policymakers need and decision makers must be presented with evidence about what it costs to make the kinds of changes that have been made in the PJM wholesale markets and the changes that have occurred in the state retail markets, and what about the cost savings that have resulted from these reforms. While the CAEM Study recommends that the PJM model be emulated in other parts of the country, it does not provide any insights into what it would cost to emulate that model, nor in fact what the model is, or what parts of the model are good and what parts should be rethought. The CAEM Study fails to provide policymakers with the kind of information that is absolutely essential for discerning whether restructuring makes sense in other parts of the country.
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1. INTRODUCTION

On September 22, 2003, the Center for Advancement of Energy Markets (CAEM) released a study entitled “Estimating the Benefits of Restructuring Electricity Markets: An Application to the PJM Region” (hereafter referred to as the ‘Study’). This CAEM Study claims to estimate the benefits of restructuring the wholesale electricity market in the PJM region. Its core finding is that the present discounted value of future savings to ultimate customers in the PJM region from “current restructuring efforts” will be about $28.7 billion.

At the request of the National Rural Electric Cooperative Association, we have reviewed the analytical methods used to calculate the estimated benefits. We find that the Study’s quantitative analysis is so fundamentally flawed that the numerical results are not worth serious consideration as even ballpark estimates, and that the qualitative analysis emphasizes evidence that supports CAEM’s pro-competition stance while it ignores evidence that contradicts that stance.

In critiquing the Study, we are critiquing neither the concept of electricity market restructuring in general nor the PJM market in particular. Our critique is instead motivated by our disappointment with the poor quality of the Study and our desire to see legitimate estimates of restructuring’s benefits. The CAEM Study provides no such estimates.

The Study never makes clear what it means by its use of the term restructuring. In the Study, the term is used broadly to refer to anything and everything that has taken place in the PJM region to both the wholesale and retail electric markets during the period 1997 to 2002. But restructuring of the retail and wholesale electric markets represent two parallel, yet complementary reform movements underway in the electricity sector in the 1990s. They should be separated sufficiently in order for a discussion of these events and any analysis of their impacts to be comprehensible. The restructuring of the retail markets involved one set of activities while the restructuring of the wholesale markets entailed another set of events and activities.

\[\text{PJM includes all of Delaware, the District of Columbia, Maryland, and New Jersey; almost all of Pennsylvania; and parts of Ohio, Virginia, and West Virginia.}\]

\[\text{See, for example, the Study at page 4. The Study presents benefits as $28.524 billion in the table on page 5 (rounded to $28.5 billion on page 4) and as $28.656 billion on page 47. In our discussion, we use the $28.656 billion figure (rounded to $28.7 billion).}\]

\[\text{In fact, as economists we are keenly aware of the failings of electricity regulation, and we strongly support market solutions to electricity problems when market solutions are superior to regulated solutions. Furthermore, we believe that the PJM electricity market has several commendable design features that are well worth emulation in other electricity markets.}\]
Our critique is organized as follows. Section 2 summarizes the Study, emphasizing the quantitative analysis that underlies its major finding. Section 3 defines the events that shape the restructuring of the wholesale and retail markets, which is important to place any discussion of benefits and costs into the proper context. Section 4 describes in detail the major flaws in the Study’s quantitative analysis. Section 5 lists several other notable problems with the Study. Section 6 generally describes the benefits and costs of power industry restructuring. Finally, Section 7 presents a summary and conclusions.

2. SUMMARY OF THE STUDY

Most of the Study is devoted to general discussions of the history of electric utility regulation, the features of the PJM market, questions concerning optimal capacity and reserve markets, and the expected sources of benefits of power market restructuring. It identifies the following primary sources of potential benefits from power market restructuring:

- efficiency increases and corresponding cost reductions in the investment and operation of generation due to wholesale market competition (Section 4.1);
- consumer benefits and cost savings from the effects of price responsive demand (Section 4.2); and
- lower costs and increased consumer benefits from retail competition and product differentiation (Section 4.3).

By contrast, the Study’s Executive Summary and CAEM’s publicity concerning the Study are mostly dedicated to presenting the core quantitative results that appear in the Study’s Section 5.3 and Section 5 Appendix.

Although other parts of the Study say that the primary source of potential restructuring benefits is the lower costs brought about by increased competition, the quantitative estimates of restructuring are based on changes in retail prices over time. The Study justifies this approach by claiming ‘Much of the benefit from current restructuring is captured by reduced prices to ultimate customers.’

The Study recognizes that ‘Constructing reliable estimates of these benefits requires estimating the change in prices to customers due specifically to restructuring, and not due to other factors.’

It notes that changes in retail electricity prices in a restructured region may occur due to a number of possible factors, including the following:

- changes in wholesale costs or prices due to external factors such as changes in fuel costs or to production efficiencies brought on by restructuring;
- changes in allowed recovery of stranded costs; and
- the nature of regulated retail rates negotiated by utilities and regulators as part of a restructuring process.

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8 Study at pages 42-43.
9 Study at page 46.
The Study further points out that the challenge of calculating the cost-saving benefits due to restructuring requires isolating that portion of any observed retail price changes that may be attributed directly to restructuring.\(^\text{10}\)

But instead of unraveling the relative importance of these factors in contributing to recent reductions in retail prices in the PJM area, the Study simply compares the reduction in inflation-adjusted retail electricity prices between 1997 and 2002 in the states within the PJM area to the corresponding reduction in retail electricity prices in three neighboring states; and from this comparison it infers the portion of reduced electricity expenditures in PJM that are due to restructuring rather than from other causes. The Study then assumes that these reduced expenditures will continue into the indefinite future and that the eventual expiration of stranded cost recovery will be an additional benefit of restructuring; and it discounts these benefits back to the present to produce its $28.7 billion estimate of the benefits of restructuring in the PJM area.

Furthermore, the Study never makes clear what it means by its use of the term restructuring. In the Study, the term is used broadly to refer to anything and everything that has taken place in the PJM region to both the wholesale and retail electric markets during the period 1997 to 2002. But restructuring of the retail and wholesale electric markets represent two parallel, yet complementary reform movements underway in the electricity sector in the 1990s. They should be separated sufficiently in order for a discussion of these events and any analysis of their impacts to be comprehensible. The restructuring of the retail markets involved one set of activities while the restructuring of the wholesale markets entailed another set of events and activities.

3. AN OVERVIEW OF ELECTRICITY RESTRUCTURING

The Study never really defines what it means by the term ‘restructuring.’ It provides no discussion of the changes that took place at the wholesale and retail levels in the PJM region or of the events and processes at work within the nation that might contribute to an explanation of changes in retail rates. The distinction between wholesale restructuring and retail restructuring is important because without it there is no means to discover what, if any, market or institutional changes at the wholesale and retail levels may have contributed to retail rate declines during the period. Therefore, we briefly digress from the critique itself to describe what took place in the country and in the PJM region at the retail and wholesale levels.

3.1. Generation Sector Restructuring

The primary impetus for restructuring of the generation sector and ultimately wholesale and retail markets was incentive failures in generation, particularly the poor incentives for utilities to control nuclear power costs or to adopt renewable technologies back in the 1970s. The Public Utilities Regulatory Policy Act (PURPA), passed in 1978, was designed to address the renewables problem. The success of the PURPA generators in reducing costs, at the same time that utility retail prices were rising, led large industrial customers to lobby successfully for the

\(^{10}\) Study at page 43, states ‘[t]he task of capturing the benefits of restructuring requires isolating the price increment (\(\Delta P\)) produced by restructuring.’
passage of the Energy Policy Act (EPAct) of 1992, which was the starting gun for the state restructuring efforts of the 1990s.

States that implemented retail competition programs have also strongly encouraged or required the affected utilities to separate their regulated transmission and distribution businesses from their wholesale generation and marketing activities. The first states to implement retail competition programs also required their utilities to divest substantially all of their generating capacity through an auction process (e.g., in California, Massachusetts, New York, Maine, and Rhode Island). Other states that have implemented retail competition programs permitted the utilities under their jurisdiction to retain the bulk of their generating assets and to move them into separate unregulated wholesale power affiliates within a holding company structure (e.g., in Pennsylvania, Maryland, and New Jersey). A few utilities in these states chose voluntarily to divest their generating assets anyway. Whether the generating assets were divested or transferred to affiliates, the utilities affected typically retained some type of transition or “default service” obligation to continue to supply retail customers who had not chosen a competitive retail supplier at prices determined through some type of regulatory transition “contract.” The terms, conditions and durations of these obligations vary widely from state to state and sometimes vary significantly among utilities within a state (e.g., in Pennsylvania).

The last few years has seen a significant entry of new unregulated generating capacity seeking to supply power to both unintegrated distribution companies and to vertically integrated utilities that have been encouraged or required by state regulators to meet their incremental generation needs through wholesale market purchases. About 80% of the new generating capacity introduced between 1997 and 2002 was unregulated “merchant” or “non-utility” capacity built to make sales in competitive wholesale markets. Up to mid 2001, investments in new merchant generating projects and trading power in wholesale markets was perceived to be a booming business with enormous profit potential and was pointed to as a successful outcome of policies aimed at stimulating competition in electricity. However, the boom turned to into a bust. One can now find abundant generating capacity in service in almost all regions of the country, a merchant generating and trading sector in difficult financial shape, and many planned new generating plants (even some under construction) being cancelled or indefinitely postponed.

3.2. Wholesale Market Restructuring

The Federal Energy Regulatory Commission’s (FERC’s) initial efforts at wholesale market reform began shortly after the passage of EPAct. FERC issued several landmark decisions regarding open access to the transmission system in particular utilities’ rate cases, and followed these with its issuance of a policy statement on transmission pricing and access in 1994. In March 1995 FERC issued its “MEGA-NOPR”\(^\text{11}\) that culminated in its issuance of Order Nos. 888 and 889 in 1996, which initiated more aggressive reform of wholesale market institutions. FERC refined the Order 888 rules through its Order 2000. These orders established rules under which jurisdictional transmission owners were required to provide access to their transmission systems to third parties, and associated requirements to provide balancing and operating reserve services using formulas or procurement methods specified in FERC regulated transmission

\(^{11}\) NOPR stands for Notice of Proposed Rulemaking.
tariffs, to make information about the availability of transmission service, purchasing, and scheduling transmission capacity easily available to all market participants.

The three Northeastern power pools (i.e., PJM, New York, and New England), California, Texas, and most recently, several Midwestern states (i.e., through the Midwest Independent Transmission System Operator), took a more comprehensive approach to developing new wholesale market institutions. They created independent system operators (ISOs) to schedule and dispatch generation and demand on transmission networks with multiple owners, to allocate scarce transmission capacity, to develop and apply fair interconnection procedures for new generators, to operate voluntary public real-time and day-ahead markets for energy and ancillary services, to coordinate planning for new transmission facilities, to monitor market performance in cooperation with independent market monitors, and to implement mitigation measures and market reforms when market performance problems surfaced. FERC’s proposed Standard Market Design (SMD) rules would extend its selection of the best practices drawn from the experience with these ISOs to the rest of the country. However, the U.S. has a patchwork of different wholesale market institutions operating in different regions of the country. Moving power from one regional network to another with each operated by different system operators employing different protocols is sometimes difficult or costly and coordination imperfections between control area operators increase costs of energy, operating reserves, and congestion especially during emergency conditions.

3.3. Retail Market Restructuring

Fundamental restructuring and competition initiatives in the state retail markets can be traced to electricity policy debates that began in California and a few states in the Northeast (e.g., Massachusetts, Rhode Island, New York, Pennsylvania, Maine, and New Jersey) in the mid-1990s, stimulated by the supporting transmission and wholesale market rules and regulations issued by FERC (e.g., Order Nos. 888 and 889). These debates eventually led to regulatory decisions and state legislation in some states that embraced competitive electricity market models. Retail competition programs first began operating in Massachusetts, Rhode Island and California in early 1998. By the end of 2000, the concept spread to about a dozen states, including the states within the PJM footprint. By that time an additional dozen or so states had announced plans to introduce similar programs.

The early state restructuring and competition programs included unbundling the retail supply of generation services from the supply of distribution and transmission services, and giving retail customers the opportunity to choose their power supplier from among competing retail suppliers. These programs included various utility restructuring requirements designed to separate competitive services (i.e., generation and retail supply) from monopoly services (i.e., distribution and transmission), services that would continue to be regulated. In addition, the programs involved arrangements for a transition period including stranded cost recovery, generation assets sales, and regulated retail supply services. Transition period arrangements typically included a mandatory reduction of regulated retail rates for all consumers (at least residential consumers) and some type of default service arrangement to supply retail customers with a regulated

12 And it was presumed that the regulation of the wires segment of the business would be improved as well over the previous regulation of the vertically integrated utility.
backstop retail power supply option until they migrated to competitive retail suppliers during what typically was expected to be a short transition period (i.e., a couple of years).

Since 2000, however, no new states have announced plans to introduce competitive reforms of this type and about nine states with reform plans have delayed, cancelled, or significantly scaled back their electricity competition programs. Federal pro-competition electricity legislation has stalled. The proposed Congressional legislation would delay certain features of competitive market design, including mandatory participation in regional transmission organizations. The California electricity crisis of 2000-2001, Enron’s bankruptcy, the financial collapse of many merchant generating and trading companies, volatile wholesale market prices, rising real retail prices in some states, phantom trading and fraudulent price reporting revelations, accounting abuses, a declining number of competitive retail supply options for residential and small commercial customers in many states, and continuing allegations of market power and market abuses in wholesale markets have all helped to take the luster out of electricity “deregulation” in many parts of the United States. The average real (i.e., inflation-adjusted) retail price of electricity in the U.S. increased for the first time in 15 years in 2000 for industrial customers and in 2001 for residential customers, though inflation-adjusted retail prices fell again in 2002.

At the very least, the pace of wholesale and retail competition and the supporting restructuring and regulatory reforms has slowed considerably. Many states have concluded that these types of electricity sector reforms may not be in the best interest of consumers in their states, or that it is prudent to wait to see if policymakers can figure out how to make competition work well at the wholesale level and can demonstrate that these reforms will bring long-term benefits for consumers. At the same time, most of the states in the Northeast, a few in the Midwest, Texas, and FERC are committed to moving forward with the development of competitive wholesale and retail markets and to making them live up to expectations.

Initial interest in electricity reforms surfaced in the states with the highest retail electricity prices and where the apparent gaps between wholesale and retail prices were greatest, which included California, Massachusetts, Rhode Island, New York, New Jersey, Maine, and Pennsylvania. The political pressures for reforms in these states, and in particular for retail competition, came from lobbying activities by industrial customers, independent power producers, and would-be electricity marketers with experience in the natural gas industry. Enron played a major role in stimulating interest in restructuring and competition in almost every one of these “pioneer” states. The primary selling point to state regulators and legislators was that by introducing competition, retail prices would fall significantly to reflect the lower-priced power available in the wholesale market. Incumbent utilities in these states initially opposed these retail competition proposals due to the potential for stranding sunk costs associated with investments in generation facilities, but ultimately negotiated settlements that provided for recovery of a significant fraction of these sunk costs.13

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13 How retail prices could fall dramatically to reflect lower wholesale prices and utilities could recover their stranded costs—roughly the difference between regulated generation prices and the expected wholesale price of electricity—was a bit of questionable arithmetic that was largely glossed over.
4. MAJOR FLAWS IN THE STUDY’S QUANTITATIVE ANALYSIS

The discussion in Section 3 points to the types of cost-saving efficiency improvements that might be produced by the restructuring of electricity markets. However, the Study makes no effort to identify or quantify such improvements. As a result, the Study’s benefit estimates are so badly flawed they do not merit serious consideration. They are nothing more than extrapolations of relative retail price trends in PJM and a non-comparable neighboring region. The Study does not identify, quantify, or even discuss the costs of restructuring the PJM wholesale or retail markets. In fact, apart from indirect references, the Study does not establish the context in which the observed price changes were occurring. It does not bother to explain what took place in the PJM retail and wholesale electricity markets during this period to provide a foundation for even a cursory explanation of the changes in retail prices. Readers are left to ponder these things on their own.

Of the Study’s asserted $28.7 billion benefit of restructuring, $20.1 billion reflect price changes in PJM relative to those of ‘neighboring’ states during 1997-2002, while $8.6 billion are asserted to be ‘post stranded cost recovery’ benefits. This section begins by explaining why the Study’s $20.1 billion figure bears little or no relationship to the benefits of restructuring. It then explains why the $8.6 billion ‘benefit’ is entirely due to a cause other than PJM’s restructuring. Finally, it discusses the significant costs of restructuring that are ignored by the Study’s quantitative analysis.

4.1. The Study Errs in Finding a $20.1 Billion Benefit from Historical Price Trends

The Study finds $20.1 billion of restructuring benefits by comparing retail price reductions in PJM over the period 1997-2002 with those of three ‘neighboring’ states: Kentucky, North Carolina, and Tennessee. As the Study states:

“This analysis compares the electricity price declines in the PJM states with those of neighboring states that are not restructuring and with the total U.S. The relatively large price declines in the PJM region are a result of successful restructuring in the PJM region 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.”

In other words, the Study arbitrarily attributes to restructuring 100% of the benefits of the relative declines in average revenues in the PJM states during 1997-2002. Even though it acknowledges that other factors may account for a part of these benefits, the Study does not make any attempt to quantify the extent to which the average revenue decline may be due to these other factors.

- The Study’s benefit estimate does not reflect the extent to which the average revenue declines might be due to regulatory idiosyncrasies or regulatory accounting effects that were built into the rate process, as would occur if PJM’s utilities happened to reach the

14 The $8.6 billion figure appears on page 54, Table A1, column ‘PV Stranded Cost Rec.’ The $20.1 billion figure equals $28.7 billion minus $8.6 billion.
15 Study at page 43.
end of the amortization of large past expenses during the period 1997-2002. Indeed, although the Study recognizes that a portion of its measured benefits of restructuring are due to a regulatory bargain in New Jersey that temporarily reduced retail prices by 15% (15% is in error, the rate reductions were actually 10%), and even though the text acknowledges that it is therefore "likely that the benefits estimates for New Jersey are optimistic," the benefit estimate (touted by the Study and by CAEM) continues to include the price effects of this regulatory bargain among its $20.1 billion of restructuring benefits.

- The Study does not consider whether PJM’s utilities may have merely enjoyed relatively favorable movements in their input prices (e.g., fuel, labor, land) during the 1997-2002 period that were passed through to customers in the form of lower rates, thus reducing average revenues.

- The Study does not consider whether PJM’s utilities and generating plants might have become relatively more efficient over the period 1997-2002 because of causes unrelated to restructuring and those efficiency gains were also passed through to customers in the form of lower rates, thus reducing average revenues.

- The Study does not consider whether PJM’s utilities and generating firms might have become less profitable over the period 1997-2002 relative to their counterparts in the neighboring states, meaning that PJM’s prices may have been affected by a temporary local fluctuation in business or regulatory conditions.

In short, the Study includes among the benefits of restructuring the price effects of everything that happened in the PJM region during 1997-2002, including things that had little or nothing to do with restructuring. Furthermore, the Study presumes that the relative price changes from 1997-2002 represent a permanent benefit that extends into the far future. Consequently, the effects of fluctuating circumstances during 1997-2002 are included in the Study’s estimates of benefits that continue into the indefinite future.

A close look at the details of the Study reveals the extraordinary weakness of its quantitative analysis. To obtain its estimated $20.1 billion benefit of restructuring PJM wholesale and retail markets, the Study took the following three steps:

1. The Study estimated the present value of future savings extrapolated from recent retail price reductions in PJM. By multiplying the retail price changes in PJM during 1997-2002 by forecast future sales in PJM, the Study obtained an estimate of retail customers’ savings in future years. It then calculated the present value of these savings to be $30.2 billion.\(^1\)

2. The Study estimated the present value of retail price reductions in the neighboring states relative to their total retail revenues. It did this by multiplying the retail price changes in the three neighboring states during 1997-2002 by forecast future sales in those states to get an estimate of retail customers’ savings in future years in those states. It then

\(^{16}\) Study at pages 44-46.

\(^{17}\) The methodology for this step is explained in the Study at page 44. Detailed results appear in Table A1 on page 54. $30.2 billion approximates $38.766 billion minus $8.614 billion, where the latter two figures are from Table A1.
calculated the present value of these aggregate savings, finding that this value was about
46% of 2002’s retail electricity revenues in those states.\(^{18}\)

3. *The Study inferred from the results in the neighboring states the portion of PJM’s retail
price reductions that would have occurred in the absence of restructuring.* Based upon
Step 2’s findings for the neighboring states, the Study assumed that, in the absence of
restructuring PJM retail customers would have enjoyed future retail savings with a
present value approximating 46% of PJM retail electricity revenues in 2002. Because
retail revenues in the PJM states were $22.00 billion in 2002, the Study inferred that the
estimate of Step 1 includes $10.1 billion (equals 46% of $22.0 billion) of savings that
would have occurred without restructuring. The restructuring benefit of $20.1 billion
equals $30.2 billion from Step 1 minus this $10.1 billion.\(^{19}\)

These three steps comprise the *entire quantitative analysis* in support of $20.1 billion of the
restructuring benefits found by the Study. The validity of the analysis rests *entirely* on the
assumption that the neighboring states provide a valid benchmark for removing from PJM’s
price decline that portion of the price decline that was not caused by restructuring, so that the
remainder reflects only the portion of the price decline that is due to restructuring. But the
Study’s own data show that this assumption flies in the face of common sense.

The absurdity of the Study’s approach can be seen by examining Table A2 (at page 55). This
table shows that, during 1997-2002, the neighboring states had a price decline that supposedly
leads to cost savings with a present value approximating 46% of their current costs. This is the
46% figure that was used in Step 3, described above. But Table A2 also shows that the price
debles for North Carolina and Tennessee will supposedly lead to cost savings that are 76% and
6% of those states’ respective costs. This difference between 76% and 6% is interesting for two
reasons. The less important reason is that it shows that the Study’s results are sensitive to the
choice of benchmark: the results at Step 3 can vary by billions of dollars depending upon the
neighboring states that are chosen for comparative purposes. The more important reason is that
it raises the question of why price declines were so much greater in North Carolina than in
Tennessee during the 1997-2002 period. By the Study’s own logic, it could be asserted that the
benefit of North Carolina’s restructuring can be measured by the amount by which the price
debles in North Carolina exceeded the price decline in Tennessee. That argument would be
absurd, however, because there has been no restructuring in North Carolina, so the relative price
debles must have proceeded from other causes. But the argument is equally absurd when
applied to PJM, because even though PJM has had restructuring, the Study provides no evidence
that PJM’s relative price decline has not proceeded from other causes.

There are also serious reasons to be concerned about whether the so-called “neighboring” states
constitute a legitimate benchmark for separating the portion of PJM states’ average revenue
changes that is due to restructuring from the portion that is due to other causes. In a scientific
study, one ordinarily wants a benchmark that is as similar as possible to the study’s subject. But
the physical, regulatory, and cost bases in Kentucky, North Carolina, and Tennessee are very

\(^{18\text{ The methodology for this step is explained in the Study at pages 46-47. Detailed results appear in Table 5 on page 48.}}\)

\(^{19\text{ The methodology and results for this step is explained in the Study at page 47.}}\)
different than those in PJM, both historically and at present.\textsuperscript{20} In particular, in 2001, after PJM had achieved most of its relative price reduction, PJM had average retail prices that were still 44\% higher than those in these ‘n neighboring’ states.\textsuperscript{21} In other words, what happened to PJM’s retail rates during the years 1997-2002 may have been nothing other than catching-up with its neighbors. Because the retail prices in the PJM region were and are substantially higher than those of these neighbors, PJM’s power system has significantly more costs to cut than its neighbors: with or without restructuring, you would expect PJM to be reducing costs and prices relative to most other regions. A reasonable interpretation of the price history of 1997-2002 might be that PJM’s utilities merely managed to reduce their relatively high costs down to levels nearer those of the neighboring states. It may be true that restructuring provided incentives that drove a portion of the PJM utilities’ price reduction; but the Study provides no evidence that this is true.

Tables 1 and 2 present a summary of the nominal and inflation-adjusted average residential revenues (referred to in the Study as prices) in the PJM states and the ‘neighboring states’ along with the U.S. averages for the period 1997 to 2002.\textsuperscript{22} The last two rows of each table list the absolute and percentage changes in average revenues from 1997 to 2002.

\textbf{Table 1 Nominal Average Residential Revenues in the U.S., the PJM States, and ‘Neighboring States’ (¢/kWh)}

<table>
<thead>
<tr>
<th>Year</th>
<th>U.S.</th>
<th>PA</th>
<th>NJ</th>
<th>MD</th>
<th>DE</th>
<th>KY</th>
<th>NC</th>
<th>TN</th>
</tr>
</thead>
<tbody>
<tr>
<td>1999</td>
<td>8.31</td>
<td>9.20</td>
<td>11.28</td>
<td>8.37</td>
<td>9.18</td>
<td>5.59</td>
<td>8.01</td>
<td>6.36</td>
</tr>
<tr>
<td>2000</td>
<td>8.37</td>
<td>9.54</td>
<td>10.21</td>
<td>7.96</td>
<td>8.55</td>
<td>5.50</td>
<td>7.99</td>
<td>6.34</td>
</tr>
<tr>
<td>2001</td>
<td>8.62</td>
<td>9.56</td>
<td>10.22</td>
<td>7.70</td>
<td>8.60</td>
<td>5.55</td>
<td>8.16</td>
<td>6.38</td>
</tr>
<tr>
<td>2002</td>
<td>8.53</td>
<td>9.74</td>
<td>10.36</td>
<td>7.65</td>
<td>8.66</td>
<td>5.69</td>
<td>8.16</td>
<td>6.44</td>
</tr>
<tr>
<td>Chng 97-02</td>
<td>0.06</td>
<td>-0.20</td>
<td>-1.68</td>
<td>-0.69</td>
<td>-0.59</td>
<td>0.07</td>
<td>0.10</td>
<td>0.40</td>
</tr>
<tr>
<td>%Chng 97-02</td>
<td>0.72</td>
<td>-2.04</td>
<td>-13.94</td>
<td>-8.28</td>
<td>-6.33</td>
<td>1.25</td>
<td>1.28</td>
<td>6.55</td>
</tr>
</tbody>
</table>

\textsuperscript{20} Tennessee is the prime example, since it is dominated by the Tennessee Valley Authority, a federal power authority, which has entirely different regulatory, governance, and financial arrangements than the regulated utilities populating either of the other ‘benchmark’ states or the utilities in the PJM region states.

\textsuperscript{21} Of utilities with annual sales in excess of 1,500 GWh, the load-weighted average retail price was 5.36¢ per kWh in Kentucky, North Carolina, and Tennessee, while the similar figure for PJM was 7.73¢ per kWh. The underlying data are from \textit{Public Utilities Fortnightly}: February 1, 2003, p. 12; May 1, 2003, p. 11; and September 15, 2003, p. 10.

\textsuperscript{22} The Study cites the Energy Information Administration (EIA) as the source of its data, in particular the data file entitled “Historical Retail Sales, Revenues and Average Revenue per Kilowatt-hour by State and by Sector: 1990 to Current Month,” obtained from the EIA website. Average revenues in $/kWh equal total revenues divided by total sales in kWh. Real average revenues are obtained by deflating nominal average revenues by the Bureau of Labor Statistics’ Consumer Price Index, with 1982-1984 = 100 (source, BLS).
Laurits R. Christensen Associates, Inc.

Table 2 Inflation-adjusted Average Residential Revenues U.S., the PJM States, and “Neighboring States” (¢/kWh)

<table>
<thead>
<tr>
<th>Year</th>
<th>U.S.</th>
<th>PA</th>
<th>NJ</th>
<th>MD</th>
<th>DE</th>
<th>KY</th>
<th>NC</th>
<th>TN</th>
</tr>
</thead>
<tbody>
<tr>
<td>1998</td>
<td>8.24</td>
<td>9.74</td>
<td>11.14</td>
<td>8.27</td>
<td>8.96</td>
<td>5.54</td>
<td>7.88</td>
<td>6.23</td>
</tr>
<tr>
<td>1999</td>
<td>8.01</td>
<td>8.86</td>
<td>10.87</td>
<td>8.06</td>
<td>8.85</td>
<td>5.39</td>
<td>7.72</td>
<td>6.13</td>
</tr>
<tr>
<td>2000</td>
<td>7.80</td>
<td>8.90</td>
<td>9.52</td>
<td>7.42</td>
<td>7.97</td>
<td>5.13</td>
<td>7.45</td>
<td>5.91</td>
</tr>
<tr>
<td>2001</td>
<td>7.81</td>
<td>8.66</td>
<td>9.26</td>
<td>6.98</td>
<td>7.80</td>
<td>5.03</td>
<td>7.40</td>
<td>5.78</td>
</tr>
<tr>
<td>2002</td>
<td>7.61</td>
<td>8.69</td>
<td>9.25</td>
<td>6.83</td>
<td>7.73</td>
<td>5.08</td>
<td>7.28</td>
<td>5.75</td>
</tr>
<tr>
<td>Chng 97-02</td>
<td>-0.86</td>
<td>-1.25</td>
<td>-2.80</td>
<td>-1.52</td>
<td>-1.52</td>
<td>-0.54</td>
<td>-0.78</td>
<td>-0.30</td>
</tr>
</tbody>
</table>

From Table 1, the declines in the nominal average residential revenues in the PJM states buck the national trend during the period 1997 to 2002. Nominal average residential revenues in the U.S. rose just under 1% from 1997 to 2002, while in the PJM states, average revenues declined anywhere from 2% in Pennsylvania to nearly 14% in New Jersey. Each of the three ‘neighboring states” had increases greater than 1%, higher than the national average. Thus, Table 2 naturally reveals that the declines in real average residential revenues in the PJM states are greater than in the U.S. overall and in the ‘neighboring states.’

Percentage changes in real average residential revenues in the PJM states relative to the U.S. or any subset of ‘benchmark’ states does not constitute prima facie evidence of the effects of restructuring in wholesale and retail electric markets. Without a more detailed examination of what took place in these PJM states, declines in average residential revenues during this period cannot be attributed directly to gains in efficiency or reductions in costs that result from incentives inherent in competitive wholesale electricity markets. Even if there were efficiency gains that resulted from the restructuring of the PJM wholesale market, they could not have been reflected in residential rates during this period because all of the retail prices were fixed during the transition periods, which in many cases extend beyond 2002. The only residential customers who could have possibly benefited from increased efficiency in the wholesale market would have been those who chose an alternative supplier. In the PJM states, residential customers choosing an alternative supplier typically represents about 1 to 3% of all residential customers. An examination of alternative suppliers’ rates reveals that their prices are typically higher than the incumbents’ ‘price to compare.’

When considered in historical context and in light of what took place in the PJM states, Tables 1 and 2, reflect two major effects. With the sole exception of Maryland, prices in each of the PJM state are reverting toward the national mean. In other words, except for Maryland, each state’s prices are closer to the national average in 2002 than in 1997. This implies that the initial differences among states are partly due to causes (e.g., one-time mistakes or windfalls) that are

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23 The exception in Pennsylvania is in PECO Energy's service territory where 15.8% of the residential customers were assigned by the state to a Competitive Discount Service because an insufficient number of residential customers had voluntarily chosen an alternative supplier.

24 For example, in Pennsylvania, Green Mountain Energy Company is the only alternative supplier competing statewide with the incumbents, offering energy supplied from renewable sources at prices from 1 cent to 2 cents per kWh higher than the incumbents.
fading over time. A second reason for the relatively large fall in retail rates in the PJM states is that those states mandated relatively large retail rate reductions. Another reason is that some of those states’ utilities were able to rapidly recover some sunk costs through the successful sale of their generation assets. Although these mandated rate reductions and asset sales permitted more rapid recovery of sunk costs, they are attributable to the political process pursued in these PJM states rather than to any real economic cost impacts. The mandated rate reductions are temporary, lasting for periods of years that vary with the agreed upon transition period.

Table 3 summarizes the percent reductions in residential rates mandated by state laws or the state regulators in PJM states during the study period 1997-2002. The vast majority of the nominal price changes from 1997 to 2002 in these states derive from these mandated retail rate reductions. For example, in Delaware, nominal average residential revenues declined by 6.33% between 1997 and 2002, and the average mandated rate reductions were 6.3%. In Maryland, nominal average revenues declined by 8.3% while mandated rate reductions averaged about 6.9%, providing an explanation of about 83% of the change. Pennsylvania appears to be an anomaly in that mandated residential rate reductions in Pennsylvania averaged about 8%, but the nominal residential revenues only declined about 2% during this period.25

The Study assumes that the average revenue declines from 1997 to 2002 represent permanent gains. However, the average revenue changes are explained by mandated retail rate reductions that are assured only during mandated transition periods. What happens after the transition period ends is anyone’s guess. It is quite possible that the rates will increase at the close of the transition period. New Jersey illustrates this point. The nominal average revenues in New Jersey declined by about 14%, while the mandated rate reductions averaged 10%. However, when the transition period ended in August 2003, residential rates were increased 15%, obliterating any “restructuring savings.” The Study acknowledges this fact by stating “[t]he estimated cost saving to New Jersey customers in year 2002 of about $1.4 billion has been realized, but future benefits are less certain.”26 The New Jersey Division of Ratepayer Advocate expresses a diametrically opposite opinion regarding the benefits of restructuring for New Jersey residential customers.

The intent of EDECA27 was to achieve lower rates and better service by encouraging competition among energy suppliers. However, as we now know, energy deregulation has not worked as envisioned. Today, there is little competition in the state and customers cannot truly shop for electricity. According to the most recent statistics in April, out of 3.1 million residential electric customers statewide, only 1,800 have switched electricity suppliers, and out of 465,000 industrial and commercial customers, only 632 have switched to an electricity supplier other than their local utility. What is clear is that smaller

25 The explanation for why Pennsylvania residential customers do not appear to have been enjoying the fruits of the mandated rate reductions appears to lie in the fact that the basic “standard offer service” rate for energy and capacity in most of the utility service territories had risen 20% on average during the study period. This conclusion is based on a comparison of the initial “price to compare” set at the outset of the transition in 1999 and the “price to compare” today.

26 Study at page 6.

27 The EDECA refers to the New Jersey’s Electric Discount and Energy Competition Act passed by the New Jersey legislature in 1999.
users of electricity and natural gas are not receiving EDECA’s promised benefits of competition.  

Table 3 Mandated Rate Reductions in Residential Rates During the Study Period: 1997-2002

<table>
<thead>
<tr>
<th>State</th>
<th>Utility</th>
<th>% Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>PA</td>
<td>Allegheny Power (West Penn)</td>
<td>2.5</td>
</tr>
<tr>
<td>PA</td>
<td>Citizens Electric</td>
<td>8.0</td>
</tr>
<tr>
<td>PA</td>
<td>Duquesne Light</td>
<td>21.0</td>
</tr>
<tr>
<td>PA</td>
<td>Metropolitan Edison (GPU)</td>
<td>3.0</td>
</tr>
<tr>
<td>PA</td>
<td>Pennsylvania Electric Company</td>
<td>3.0</td>
</tr>
<tr>
<td>PA</td>
<td>Pennsylvania Power Company (GPU)</td>
<td>8.0</td>
</tr>
<tr>
<td>PA</td>
<td>Pennsylvania Power &amp; Light</td>
<td>4.0</td>
</tr>
<tr>
<td>PA</td>
<td>PECO Energy</td>
<td>15.0</td>
</tr>
<tr>
<td>PA</td>
<td>Average</td>
<td>8.1</td>
</tr>
<tr>
<td>NJ</td>
<td>PSEG</td>
<td>14.0</td>
</tr>
<tr>
<td>NJ</td>
<td>Atlantic City Electric</td>
<td>5.0</td>
</tr>
<tr>
<td>NJ</td>
<td>Jersey Central Power &amp; Light (GPU)</td>
<td>11.0</td>
</tr>
<tr>
<td>NJ</td>
<td>Connectiv</td>
<td>10.1</td>
</tr>
<tr>
<td>NJ</td>
<td>Rockland</td>
<td>5.0</td>
</tr>
<tr>
<td>NJ</td>
<td>Average</td>
<td>10.0</td>
</tr>
<tr>
<td>MD</td>
<td>Potomac Electric</td>
<td>7.0</td>
</tr>
<tr>
<td>MD</td>
<td>Baltimore Gas &amp; Electric</td>
<td>6.5</td>
</tr>
<tr>
<td>MD</td>
<td>Allegheny Power</td>
<td>7.0</td>
</tr>
<tr>
<td>MD</td>
<td>Connectiv</td>
<td>7.0</td>
</tr>
<tr>
<td>MD</td>
<td>Average</td>
<td>6.9</td>
</tr>
<tr>
<td>DE</td>
<td>Delmarva Power &amp; Light</td>
<td>7.5</td>
</tr>
<tr>
<td>DE</td>
<td>Delaware Electric Cooperative</td>
<td>5.0</td>
</tr>
<tr>
<td>DE</td>
<td>Average</td>
<td>6.3</td>
</tr>
</tbody>
</table>

The Ratepayer Advocate further states that “artificial rate reductions imposed by EDECA did not permit these new suppliers to make a profit.” The Ratepayer Advocate continues:

Although ratepayers enjoyed lower utility bills for the past four years because of the 10% reduction and the rate caps imposed under EDECA, electric utilities were not able to recover the costs they incurred in purchasing energy. During this transition period, the state’s four electric utilities have been buying power at rates that have steadily increased while charging customers rates that have been kept artificially low…. An unforeseen consequence of EDECA has been the accumulation of large deferred costs that the utilities amassed by buying power to meet their customers’ demand during the transition period, which began August 1, 1999. At the time, it was believed that since New Jersey’s energy rates were

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29 The averages in this table are not load-weighted, but simple averages across the utilities within the state.
30 The averages in this table are not load-weighted, but simple averages across the utilities within the state.
31 Ibid. at page 2, emphasis added.
already high, the price of power would not exceed these rates. But because of the volatility in energy markets, particularly in skyrocketing natural gas prices, the actual cost of electricity has been more than the fixed rates set by EDECA back in 1999. As a result, the utilities have been carrying these additional costs as a deferred balance.\footnote{Ibid. at page 3.}

The Ratepayer Advocate’s words suggest that it defies common sense to infer anything about the economic benefits of retail or wholesale market restructuring from an analysis of nominal or inflation-adjusted average revenue changes over the period 1997 to 2002.

In summary, the Study seriously errs when it reaches its major conclusion that “The benefits to consumers from restructuring efforts, particularly in the wholesale electricity market, in the PJM region are substantial.”\footnote{Study at page 4.} Instead, all that the Study finds is that, during 1997-2002, average revenues in the high-cost PJM region fell by more than did the average revenues of some of its low-cost neighbors and the U.S. as a whole. The Study finds absolutely nothing about causation.

4.2. The Study Errs in Finding a $8.6 Billion “Post Stranded Cost Recovery” Benefit\footnote{The $8.6 billion figure appears in page 54, Table A1, column “PV Stranded Cost Rec.” The discussion of the “post stranded cost recovery” benefit appears on pages 52-54.}

Of the $28.7 billion of restructuring benefits that the Study claims to have found, $8.6 billion (in Pennsylvania) is what the Study calls a “post stranded cost recovery” benefit. This represents the savings that customers will supposedly enjoy when the completion of Pennsylvania utilities’ stranded cost recovery causes that state’s average retail rates to decline in year 2009.

Contrary to the Study’s claims, however, this $8.6 billion “benefit” is not due to restructuring but is merely due to the expiration of the accelerated amortization of past sunk costs. That is, the fixed costs of generation facilities built to serve native load customers were already a part of the rates customers were paying for delivered energy in Pennsylvania. These fixed costs were originally to be recovered over many years, typically thirty or more. Although the agreements reached between the state and the utilities allowed these fixed costs to be recovered over a much shorter period of time under restructuring than they would have under traditional regulation, retail prices in Pennsylvania would fall when these past sunk costs are fully amortized regardless of restructuring. This is an example of the Study attributing benefits to restructuring that are due to entirely unrelated causes.

4.3. The Study Wrongly Dismisses Major Difficulties in Restructuring Markets

In its repeated assertions that competitive “markets are much more efficient than regulated markets,”\footnote{Study at page 9.} the Study considers only one of the several important ways (i.e., market power) in which competitive markets may be less efficient than regulated markets. The Study thus appears to be dismissive or ignorant of the major difficulties that are inherent in making competitive
markets work efficiently. Because these difficulties can be costly to resolve or mitigate, their exclusion from the Study inevitably biases the results in favor of overestimating the benefits of restructuring.

4.3.1. The Study Ignores the Administrative Costs of Restructuring

The Study has no discussion or quantification of the considerable costs of organizing and operating regional transmission organizations (RTOs) and independent system operators (ISOs). The up-front organizational costs—including those of building staff and computer systems—can run over half a billion dollars. The on-going operating costs can run over a hundred million dollars per year.36

Furthermore, the Study does not recognize that PJM’s history as a tight power pool affects the applicability of PJM’s cost experience to other regions. In particular, because PJM had staffing, computer systems, communications systems, and a host of other assets prior to restructuring, its costs of restructuring and market development are likely to be substantially lower than those experienced in regions (like California and MISO) that have to create restructured markets from scratch. The Study neither provides estimates of these costs nor indicates any awareness that such costs exist.

4.3.2. The Study Ignores the Difficulties of Investment Planning

Under regulation, vertically integrated firms simultaneously plan generation and transmission. They have the ability, at least in theory, to jointly optimize investments at these two levels of production.

In restructured markets, by contrast, generators and transmission firms make independent investment decisions that they might try to coordinate through their RTOs.37 We do not yet know whether this RTO process will be any more or less expensive and efficient than the old integrated resource planning procedures. What we do know is that the joint optimization of generation and transmission investments in a market environment poses coordination problems that are more difficult to solve than in a regulated environment. If these new coordination problems lead to less efficient combinations of generation and transmission investments than under regulation, electricity consumers will bear higher costs.

4.3.3. The Study Ignores the Costs of Financial Risks

Restructuring has created financial risks that are essentially absent from a regulated system. These risks have affected merchant firms as well as established utilities, have led to bankruptcies, have led to widespread credit downgrades, and have increased the cost of capital to

36 For example, the 2003 operating budgets for PJM, the New York ISO, and the California ISO were about $187 million, about $150 million, and $237 million, respectively. Sources: financial reports of PJM and NY ISO and California ISO obtained from their websites.

the industry. These increased capital costs will be paid by consumers and are a cost of restructuring.

4.3.4. The Study Ignores the Costs of Transmission Price Uncertainty

Under traditional regulation, transmission prices were fairly stable. Whether set by tariff or by contract, these prices were based upon cost of service, which changed gradually from one year to the next. Investors in generation would not know precisely what they would pay to transport power over the many years of their generators’ lives, but they would know that the ratemaking process would result in transmission prices that changed gradually.

In restructured wholesale markets, the application of locational marginal pricing (LMP) leads to differences in the prices paid to generators and the prices paid by consumers. These differences can be quite large when the transmission system becomes congested. At these times, the differences represent a significant proportion of the price of transporting power from the generator to the consumer. An investor in generation needs to be concerned about the fact that, under LMP, the cost of transporting power (i.e., the price of transmission) from the generator to the consumer—that is, the price of transmission—can change dramatically from year to year and even from hour to hour. One of the better ways that a generator can hedge against the uncertainty in the price of transmission in an LMP market is by acquiring transmission rights (also known as ‘Financial Transmission Rights,” “Fixed Transmission Rights,” and “Congestion Revenue Rights”). Unfortunately, as presently offered by the existing ISOs, these rights have durations no greater than five years, and usually much shorter than that (i.e., lives that are certainly shorter than the lives of the generators). This is utterly inadequate to serve the hedging needs of investors in generation plant that might have forty-year lives: with transmission rights that expire after a mere five years, for example, the generator may be condemned by changes in power system conditions to pay higher congestion charges for the overwhelming majority of its life.

The uncertainty in transmission prices, combined with the lack of adequate hedging instruments, creates uncertainty that can only inhibit generation investment. This uncertainty, which arises from restructuring, may ultimately raise prices to consumers.

4.3.5. The Study is Overly Optimistic About Generation Investment

The Study states that “…the available evidence indicates that the markets are sufficiently robust to encourage new investment in generation. Hence, price risk does not appear to discourage market participation.”\(^\text{38}\) Perhaps support for these assertions can be found in evidence that is not cited by the Study. On the other hand, contrary evidence is provided by the present bankruptcies and near-bankruptcies of several major merchant generation firms, by the poor credit ratings of many electric utilities, and by the industry’s present difficulties in financing new generation. These adverse events have proceeded directly from electricity price risk. We do not yet know whether the industry will find long-run solutions to this price risk problem.

\(^\text{38}\) Study at page 24.
4.3.6. The Study Wrongly Dismisses Market Power Problems

The Study errs when it states that “The generation market is not characterized by inherent market failures, natural monopoly or otherwise.” On the contrary, the U.S. has many “load pockets” (e.g., southwest Connecticut, San Francisco, New York City) in which competition in generation services is limited and will remain limited for many years. PJM itself has significant load pockets, such as the Delmarva Peninsula. Perhaps the author is ignorant unaware of these many instances of market failure, or perhaps the author does not believe that ability to manipulate market prices constitutes a market failure, or perhaps the author believes that load pockets represent a political failure to allow construction of new transmission or generation that can create competition in load pockets. Regardless of the author’s ignorance or beliefs, however, the lack of competition in load pockets is a reality that has affected and will affect the benefits of market restructuring.

Unfortunately, neither regulators nor the industry has yet figured out how to effectively distinguish scarcity pricing from the exercise of market power. The New York ISO’s Automated Mitigation Procedure (Procedure) is apparently setting a nationwide standard for determining whether or not generators’ bids are acceptable; but there is still acrimonious debate about whether this Procedure allows generators to gouge the public or denies generators fair compensation for their product. Either way, the public incurs costs either from the gouging or from the eventual lack of sufficient generation capacity.

5. OTHER NOTABLE PROBLEMS IN THE STUDY

The Study repeatedly makes wrong or misleading statements, egregious examples of which include the following.

5.1. The Study Underestimates Public Support for Reliability

The Study wrongly castigates “public officials” and “policymakers” for supporting higher reserve margins and reliability levels than customers “prefer.” There is substantial evidence that electricity customers rationally, or irrationally, prefer to steadily pay high average prices for many years rather than occasionally suffer less costly extreme events like price spikes and blackouts. The reason that “public officials” and “policymakers” support high reserve margins and reliability levels is that they are responsive to the public: this is, for better or worse, democracy in action. The Study is wrong in asserting that uneconomically high reserve margins are due to a principal-agent problem. Instead, the problem is that the principals (the customers) are badly informed; and the agents (the public officials) are merely trying to achieve the result that the agents believe the principals want. It would be ironic for CAEM to take the Study’s implicit position that utility commissioners and legislatures should tell electricity customers what is good for them, whether the customers like it or not.

39 Study at page 15.
40 Study at pages 58-59.
5.2. The Study Fails to Recognize That Regulation Can Be Efficient

The Study asserts that “…states with relatively low electricity prices are averse to restructuring. Such low electricity prices are due to low (and sometimes subsidized) fuel costs, particularly coal and hydro power, and not to efficient regulation.”41 It is true that states with relatively low electricity prices have often been blessed by low-cost inputs. But it is also true that some states (e.g., California, New York) have high electricity prices because of bad regulatory or legislative decisions, while other states (e.g., Wisconsin) have low rates because of good regulatory decisions. Efficient regulation does sometimes deserve some of the credit.

5.3. The Study Ignores the Difficulties of Retail Service Differentiation

The Study approvingly notes that the articles in an Energy Journal Special Issue “imply that marketers could successfully offer ultimate customers variations in the quality and reliability of service as component [sic.] of bundled service.”42 However, the Study makes no mention and displays no understanding of the serious difficulties in actually implementing such retail service differentiation. In particular, because the lion’s share of service outages are due to failures in transmission and distribution, which will continue to be monopoly services, competitive marketers can have relatively little effect on the reliability of their customers’ service. As another example, in the midst of the California energy crisis, the California ISO curtailed retail customers without regard to whether their respective marketers (SCs) had sufficient generation to serve them; which means that, in emergency situations, ISOs and RTOs might ignore merchants’ promises to customers, even when merchants have the resources to back up those promises.

5.4. The Study Makes Unsubstantiated Claims That Its Views are Widely Shared

The Study repeatedly asserts or implies, without support, that the views of the author and of CAEM are widely shared by others; yet the Study provides no evidence in support of these implications. Examples include:

- “…there is now agreement that the generation market is potentially a competitive market.”43
- “The natural monopoly view of generation is now almost universally discarded…”44

On the contrary, there are a large number of market participants, state regulators, and U.S. Congressmen, as well as a large segment of the general public, who do not agree that competition in generation is appropriate, and who believe that the abandonment of generation monopolies is a serious policy error.

41 Study at page 13.
42 Study at page 58.
43 Study at page 12.
44 Study at page 26.
6. MEASURING THE NET BENEFITS OF WHOLESALE AND RETAIL MARKET RESTRUCTURING

The primary challenge in assessing the net social benefits of restructuring, either in the wholesale market or in the retail market, is to accurately identify and measure the most significant benefit and cost changes that arise from restructuring. Both benefit changes and cost changes need to be counted once and only once. The focus of the assessment should be on reductions in per unit costs of production or consumption (i.e., referred to as efficiency impacts), which measure changes in society’s overall net benefits; but cognizance may also be given to how the benefits are shared among various groups of consumers and producers (i.e., referred to as distributional impacts).

A key difficulty in conducting a cost-benefit analysis of restructuring is finding a means of isolating the economic effects that are solely attributable to restructuring. To accomplish this requires establishing a benchmark of what costs would have been during the study period had no institutional, organizational, or structural changes taken place associated with restructuring. This means the analyst must make some assumptions about what changes it would be reasonable to expect to have occurred regardless of restructuring and determine how those changes would have affected the wholesale market costs and retail market prices.

This section provides an overview of the broad categories of the benefits and costs that may attend the restructuring of the electric industry.

6.1. Benefits of Restructuring

Restructuring of wholesale electricity markets should generally lead to benefits from reductions in the generation costs. These cost reductions should occur because of access to and use of the transmission system and reductions in other aspects of the old system that stood as barriers to trade among market participants, from greater collaboration among market participants and control areas, and from improved incentives for market participants to seek ways to lower costs (i.e., to behave in ways that are more efficient). These benefits fall into several categories.

*Restructuring may lead to better generation investment decisions.* Depending upon how prices are set, restructuring may encourage better siting and technology decisions by developers of new generation. Through market-based pricing, restructuring might also encourage a better match between consumers’ needs for generation resources and the types and total quantity of generation resources.

*Restructuring may lead to more efficient operation of existing generators.* Market incentives may induce existing generators to find ways of operating with fewer inputs per MWh and of operating with higher availability factors (i.e., fewer outages).

*Restructuring may lead to more efficient regional use of existing generation.* Restructuring can help replace relatively expensive generation resources with relatively cheap generation resources. Generation production costs may be reduced by reducing barriers to trade (such as through elimination of pancaked transmission rates), by improving incentives for trade, and by improving communication among market participants. The costs of operating reserves and of installed capacity may be reduced through regional sharing arrangements or through trading mechanisms that facilitate such sharing. Improved congestion management can allow better use
of available transmission capacity. Better collaboration among market participants can also allow better coordination in the maintenance and scheduling of generation.

Restructuring may lead to better scheduling of transmission capacity. This may occur if market mechanisms can be designed and implemented in appropriate ways that will ultimately help to allocate transmission capacity to its highest valued uses, or if there is better coordination in (for example) the maintenance of transmission facilities.

Restructuring may improve power system reliability as measured by reduced failure propagation or improved voltage management, frequency management, scheduling, or real-time balancing. This can occur because restructuring may allow better coordination in the use of regional resources.

Restructuring may reduce transactions costs. This can occur because restructuring can facilitate one-stop shopping by listing regional transmission and trading opportunities on a single OASIS site and by encouraging more uniform business practices throughout a region.

Restructuring may facilitate efficiencies in the operation of power systems. There may be economies of scale in ISO or RTO operations relative to the operations of the many control areas that the ISO or RTO partly or wholly supersedes.

Restructuring may lead to better transmission investment decisions. There may be better coordination of system expansion and planning and greater benefits to the market as a whole due to the market-driven nature of investment. There may also be less need for transmission investment due to more efficient use of the existing transmission network.

Restructuring may reduce the level of regulatory oversight and the costs of regulatory intervention. On the other hand, the evidence to date is not cheering.

Note that all of the above potential benefits from wholesale market restructuring could be obtained without the additional restructuring of retail markets (i.e., retail access). However, retail restructuring could potentially produce additional benefits to consumers from greater choice of innovative pricing arrangements, and retail price competition.

6.2. Costs of Restructuring

The costs of restructuring are those of developing and operating markets, and of dealing with the problems that regulation seems to handle relatively well. These costs are discussed at length in Section 4.3.

The costs of creating and operating an RTO can be significant. They seem to average about $0.50 per MWh of regional load, but can be as high as $1.00 per MWh.45

The up-front costs are those of organizing and implementing the RTO, including the costs of software and hardware systems, facilities, communication infrastructure, and newly organized professional and support staff. But not all up-front costs are incurred by the RTO itself. Some of these costs are imposed on market participants by the market reform process, requiring

regulatory changes, innumerable meetings, and litigation. Some of these costs, such as setting up secondary power exchanges and schedule coordination services, are incurred by third parties.

The on-going costs of the RTO are those of continuing operations. Again, market participants incur some of these costs either directly or through their agents (e.g., secondary power exchanges and scheduling coordinators).

*Inconsistent generation and transmission investment plans may create unnecessary costs.* While vertically integrated firms simultaneously plan generation and transmission under regulation, generators and transmission firms make independent investment decisions in restructured markets. RTO coordination and market processes may or may not allow these investments to be jointly optimized as well in restructured markets as they were under regulation.

*Uncertain electricity prices have led to more costly financing.* Restructuring has created financial risks that are virtually absent from a regulated system. These risks have led to bankruptcies, widespread credit downgrades, and higher capital costs.

*Dealing with market power can be costly.* Each RTO and ISO is incurring the costs of implementing a market monitoring program. There are risks that further costs will be incurred if these programs malfunction. If a program fails to stop the exercise of market power, consumers will incur wholesale power costs that they may not have incurred under regulation. If a program fails to allow generators to receive sufficient scarcity rents, then consumers may eventually suffer high costs or low reliability due to insufficient generation investment.

7. CONCLUSIONS

Although we believe that restructuring wholesale electricity markets may provide long-term benefits and that restructuring efforts to-date have achieved a degree of success in some parts of the country, we are also aware that some key restructuring problems have not been solved and that restructuring initiatives have faltered in many regions of the United States. Some of these failures have occurred partly because policymakers underestimated the nature and magnitude of the technical and institutional challenges associated with successfully introducing competitive markets. We do not expect that restructuring will succeed if these problems are ignored, as they have been ignored by the CAEM Study.

A primary objection to the CAEM Study is that it is nearly devoid of balance. It acknowledges only one of the several major difficulties that are inherent in making competitive markets work efficiently, and gives short shrift to even this one difficulty (i.e., market power). The clear purpose of this Study, like CAEM itself, is to promote market solutions to electricity problems; and it almost completely ignores the evidence that is contrary to its case. As the Study states in its conclusion, “Every piece of evidence reviewed here indicates that the potential benefits from restructuring are large, if not enormous.” The author either chose to look only at the evidence that would support his conclusions, or he is unaware of the large body of evidence that contradicts his conclusions.

The Study’s core conclusion relies upon a seriously flawed quantitative analysis. The main part of that analysis asserts that because average revenue in the PJM states fell by a larger percentage

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46 Study at page 65.
than average revenue in neighboring states and in the U.S. in general during the period 1997-2002, the restructuring of the wholesale and the retail markets will lead to $20.1 billion in future benefits in PJM. If someone were to assert that the fall in the S&P 500 Index over the period 1997-2002 demonstrates that American capitalism is on its way to a future demise, CAEM would have the wit to quickly recognize that the conclusion was absurd because (among other reasons) there were many causes in the fall in stock prices and a five-year historical period is an insufficient basis upon which to make such a long-term projection. The Study is guilty of an identical absurdity. The relatively large fall in PJM prices during 1997-2002 had many causes, of which restructuring may have been negligible; and a 5-year historical period is insufficient for making any long-term projection.

As we have illustrated, the explanation of the relatively larger declines in nominal residential average revenues more likely rests with the mandated rate reductions in the PJM states. These reductions were artificial decreases in rates that had nothing to do with any economic gains from the kinds of efficiencies that restructuring of the wholesale markets might be expected to produce over the long run. As events in New Jersey clearly illustrate, the rate reductions and price freezes put in place during the transition period masked the underlying generation cost increases that finally came home to roost once the transition ended. The presumption that the gains reflected in the average revenue declines between 1997 and 2002 are somehow permanent is refuted by the New Jersey example. Other PJM states may face similar issues when their longer transition periods end.

In summary, the Study provides no legitimate quantitative support for its major conclusion that “The benefits to consumers from restructuring efforts, particularly in the wholesale electricity market, in the PJM region are substantial.”47 Instead, the Study’s quantitative analysis merely finds that prices in the high-cost PJM region fell by more than did the prices of some of its low-cost neighbors during a recent 5-year period, and that they will fall in the future when certain stranded costs are fully amortized. The Study’s quantitative results fail to demonstrate any relationship between these price changes and restructuring.

The Study cannot be relied on for any serious policy making decisions by state or federal regulators because it does not explain what is good and what is bad about the restructuring at the retail and wholesale levels in the PJM region. The Study provides no evidence that there are any benefits enjoyed by electricity customers in the PJM region that are due to restructuring rather than to mandated rate reductions.

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47 Study at page 4.