RESTRICTURING THE U.S. ELECTRIC POWER SECTOR:
A Review of the LECG Study

John Kwoka
Northeastern University
April 2007
ACKNOWLEDGMENTS

This review was commissioned by the American Public Power Association. Gratitude is expressed to Kamen Madjarov and Evgenia Shumilkina for research assistance. All opinions are the sole responsibility of the author.
I. INTRODUCTION

Vast policy changes have affected the U.S. electric power sector over the past 10 to 15 years. These include vertical divestiture of traditional utility structures, broader and deeper markets for power, new institutions to support market processes, entry by new suppliers, and displacement of cost-of-service regulation. These policies have been intended to foster stronger competition at the generation and retail stages and thereby to lower prices both directly and also indirectly through the elimination of cost inefficiencies.

Enough time has now elapsed to permit an evaluation of the actual effects of these policies relative to their promised benefits, and indeed, several evaluations have appeared in the past few years. Twelve such studies were summarized and reviewed in the November 2006 report to the American Public Power Association, “Restructuring the U.S. Electric Power Sector: A Review of Recent Studies” (hereafter “Report to the APPA”). The conclusion of that Report was that all of the surveyed studies were flawed in some significant way and should not be relied upon for their conclusions—whether favorable or unfavorable—with respect to the benefits of restructuring.

---

Even as that report was being finalized, other studies appeared. Notable among them was one entitled “Analysis of the Impact of Coordinated Electricity Markets on Consumer Electricity Charges.” This was commissioned by PJM, conducted by LECG, and released on November 20, 2006. The LECG study concludes that “the implementation of coordinated markets has served to reduce average residential rates...relative to the average rates that would otherwise have prevailed.” It estimates a reduction in the cost of electricity of somewhere between $0.50 and $1.80 per MWh and an annual benefit to PJM and NYISO consumers ranging between $430 million and $1.3 billion. The LECG study is the subject of this separate report.

We begin in the next section with a summary of observations made in the report to the APPA of methodological and other issues in these evaluation studies generally. This provides a standard against which to judge the LECG study and any new study of the effects of electricity restructuring. Section III summarizes the LECG study while Sections IV and V discuss its strengths and its deficiencies. The latter include some problems that afflict earlier studies, some new ones that follow from its particular approach, and a general failure to understand publicly owned and cooperative utilities. As a result, we conclude that the LECG study ultimately is not a sound and convincing evaluation of electricity restructuring, and hence its conclusions should not be relied upon.

II. PROBLEMS AND PITFALLS

The Report to the APPA identifies three categories of deficiencies that characterize most

---

2 In fact, at least three new studies appeared around that time. In addition to the one discussed herein, these include A Review of Electricity Restructuring in New England, commissioned by the New England Energy Alliance and authored by Polestar Communications, and A Cost-Benefit Assessment of Wholesale Electricity Restructuring and Competition in New England, commissioned by “a US electricity generating company” and authored by M. Barmack, E. Kahn, and S. Tierney of The Analysis Group.

3 LECG, p. 36.
of the 12 studies originally reviewed and undermine their credibility. In addition, that report notes three important issues that are omitted or given scant attention, rendering the evaluations in most of these studies incomplete. The following brief review of these deficiencies and omissions will be helpful in assessing the LECG study.

First, there is a general lack of precision as to the definition of “restructuring” itself in these studies. Restructuring has involved several policy initiatives at both the federal and state levels taken over a substantial period of time and in some cases involving a lengthy process of implementation. The relevant policy initiatives include at least the following:

· The Energy Policy Act of 1992
· FERC Orders 888 and 889 in 1996
· FERC Order 2000 and the subsequent formation of regional transmission organizations (RTOs)
· State-initiated divestitures of generation
· Retail access plans.

In addition, several of these initiatives served only to start the process of reform and do not comprise its complete implementation. As a result, studies that represent restructuring in its many dimensions as well as in its phase-in over time are methodologically sounder than those that treat restructuring as a single event occurring at one point in time. The latter approach vastly over-simplifies its nature, incorrectly categorizes utilities and years, and introduces errors into the data, all of which render any conclusions suspect.

Second, most studies overlook the fact that in many states actual post-restructuring prices are affected as much by mandated rate reductions or freezes, stranded cost recovery surcharges, and excess capacity as by restructuring. Rate freezes and cost-recovery surcharges are administratively set prices rather than equilibrium prices in restructured markets, obscuring rather than revealing the actual effects of policy. Similarly, excess generation capacity came on line in many regions of the country around the time of restructuring, resulting in temporarily depressed prices not indicative of market equilibrium. Studies that simply take observed prices in the immediate post-restructuring period at face value give an incorrect impression of the actual effects of restructuring.
Third, while most studies recognize that factors in addition to restructuring affect prices, not all are careful to control for those other influences. For example, some studies control only for natural gas prices over time, or select a very small number of states for cross-sectional comparison. These are unlikely to isolate the effects of restructuring as reliably as more comprehensive studies. In addition, some studies that use models based on prices from the 1990s are unlikely to project accurately after 2000, when natural gas costs were far higher and utilities began to adapt their generation technologies. Again, studies differ considerably in the care they exercise in modeling and hence in the degree of confidence one may have in their attribution of price effects to restructuring.

Apart from these deficiencies common to many of the 12 original studies, most give too little, if any, attention to three broad issues that would seem important in any overall assessment of restructuring. These are as follows:

First, restructuring has been accompanied by market power, market manipulation, and mergers involving many utilities. Wholesale power markets have become increasingly concentrated, raising concerns over market power. Mergers have become larger and more common in both the distribution and generation sectors, without obvious efficiency or other benefits. Strategic behavior and market manipulation are now fully documented in California and remain threats in other regions. To the extent that these issues are inherent in restructuring, they should be addressed in any comprehensive assessment.

Second, there is much concern in the industry, but little recognition or discussion in these studies, about the rising costs of RTOs, about their questionable governance processes, and about their failure to deal adequately with the problem of transmission congestion. Since RTOs now cover half the country and have been FERC’s preferred model for coordination, their costs and limitations also need to be assessed in studies that evaluate restructuring. Failure to do so overlooks a significant aspect of restructuring to date.

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. At present, evidence on these issues is sparse, but there are suggestions in that evidence, as well as from other restructured industries, that cost incentives
may jeopardize quality and reliability. Again, an overall evaluation of restructuring ought at least to acknowledge this concern.

The Report to the APPA evaluates all 12 studies against these criteria—the soundness of their methodologies and their comprehensiveness. In addition, each study has its own specific limitations and strength, all documented in that Report. The overall conclusion is that while various of these studies address some of these issues reasonably well, none avoids all of the significant problems. Hence, none of these studies can be judged as methodologically sound and therefore their conclusions are not reliable. Against this background, we now summarize the LECG study.

III. SUMMARY OF THE LECG STUDY

The LECG report, titled “Analysis of the Impact of Coordinated Electricity Markets on Consumer Electricity Charges” begins by asserting that many observers question the benefits of markets simply because, in contrast to airline and telecom deregulation, electricity prices have risen. The authors respond with the proposition—hardly in dispute—that many other factors have affected electricity prices, and so the proper test is actually whether coordinated markets have “reduce[d] the increase in average consumer rates that has resulted from increases in input costs for electricity generation” (p.3). In the study, LECG reviews several methodological issues involved in attempting to answer this question and then performs its own analysis. It concludes that coordinated markets have resulted in substantial reductions in rates to residential and other users.

The first part of the LECG study evaluates three common approaches to assessing restructuring—before and after, cross-sectional, and cost analyses. With respect to the first approach, it notes that comparisons of rates before and after the implementation of a new policy must confront the multiplicity of factors that might also be responsible for observed rate changes. It casts doubt on the adequacy of simple deflation by fuel costs, for example, noting that other factors also play a role and that the appropriate fuel cost adjustment factor itself may be a matter of dispute. Moreover, it observes that many states implemented retail access

4 The authors of the LECG report are S. Harvey, B. McConihe, and S. Pope
programs at the same time as the initiation of RTO-run coordinated wholesale markets. Short-term rate caps, stranded cost recovery charges, provider of last resort rates, competitive retailer rates and changes in forward hedging, it notes, all make the determination of true long-run rate effects quite difficult. We shall discuss this important recognition in the LECG study below.

The study next considers a comparison of average rates in regions implementing coordinated markets to those in regions that have not done so. This cross-sectional approach, it points out, also depends on whether everything else that is relevant has been held constant. Difference in resource mix, proximity to gas pipelines, and retail access programs all complicate this comparison in much the same way that they complicate a comparison of average rates over time.

Thirdly, LECG notes the possibility of directly estimating the cost reductions arising from the implementation of coordinated markets. In its view, this approach is undermined by the lack of transparent spot prices in regions without coordinated markets, by the resources required to apply this approach widely, and by the need to separate cost reductions from increases due to the institution of RTOs in these regions.

For all these reasons, the LECG study concludes that a new approach is required, one that: (a) distinguishes the impact of changes in fuel prices and other economic trends from the effects of implementation of coordinated markets, (b) controls for the effects of retail access programs that went into effect at much the same time as coordinated markets, and (c) takes into account the impact of differences in regional generation fuel mix and, most importantly, in gas dependence among utilities. It responds to each of these matters as follows:

First, to control for changes in fuel prices and other factors, the LECG study proposes to use pooled time series-cross section data on the prices of utilities in coordinated vs. traditional markets for the period 1990-2004. The relationship between these two sets of prices becomes the basis for predicting what prices would have been in the coordinated markets in the absence of reforms. The prices in question are average annual residential prices of each utility. Residential prices are used, according to the study, since those customers are “relatively homogeneous across the sample compared to industrial customers” (p. 22).
The LECG study initially defines “coordinated markets” as those with a combination of locational marginal pricing (LMP), day-ahead markets based on security-constrained dispatch, and financial transmission rights (p. 3). The remaining text makes clear, however, that LMP is the essential criterion and focus of attention (e.g., pp. 8, 15). The study’s methodology involves a comparison of utilities in LMP-based markets with others that are not (“traditional markets”). To identify each of these types, it begins with a map of the entire country showing which category each state falls in. But instead of using most or all utilities or states, it makes a series of sweeping exclusions. Specifically, it excludes

- California and ERCOT, which are said to be coordinated but do not use LMP,
- The Midwest, due to the recent nature of MISO and PJM westward expansion, and
- New England, since its use of LMP dates back only to 2003.

This leaves as LMP/coordinated markets only those utilities in the original (“classic”) PJM and NYISO.5

As for traditional markets, LECG again proceeds to exclude most utilities and regions. It drops from further analysis each of the following:

- All utilities in the western interconnection, because of the importance of hydro power,
- TVA customers, said to be a different regime, and
- Utilities on the western edge of MISO, which were not yet part of MISO.

This process leaves utilities in North Carolina, South Carolina, Georgia, Alabama, Florida, and Arkansas as the traditional group for statistical control purposes.

The second methodological issue addressed by the study is the confounding of the effects of coordinated markets with retail access programs, many of which were implemented at the same time. To isolate the effects of the former, the LECG study discusses three possible strategies. The first is to identify vertically integrated utilities in states without retail access programs but with coordinated markets, but there do not appear to be any such cases. Next it suggests that detailed data on the degree of forward hedging by utilities might permit

---

5 Allegheny Power became part of PJM in 2002 and is evaluated as a possible special case in the LECG study.
measurement of their cost-reducing effects in coordinated markets, but this approach is judged unworkable in practice. The study therefore settles on a third approach, namely, to examine utilities that exist in both traditional and coordinated markets and that have continued a obligation to serve throughout this period—that is, utilities never subject to retail access despite being in states where this reform was implemented. Such utilities arguably hold retail access constant so that any rate difference would be the result of the type of market in which they operate.

The LECG study asserts that these criteria are met by publicly-owned and cooperative electric utilities. Even those municipal utilities and co-ops operating in PJM and New York, it states, have maintained their obligation to serve, managed their energy costs by operating power plants or entering into long-term contracts, and used various hedging instruments to lock in transmission costs. Thus, they are said to represent a good match for their counterparts in the southeast and elsewhere where retail access programs have not arisen. LECG declares that “the use of a sample of municipal and cooperative utilities provides a relatively clean way to isolate the impact of coordinated markets on retail prices” (p. 18).

The last methodological issue discussed in the LECG study concerns an appropriate means to control for differences in generation fuel mix on retail rates. It contends that simply including generation mix as an explanatory variable raises the risk of endogeneity. That is, while generation mix might affect price, prices under coordinated markets might themselves have increased reliance on gas-fired technology. This reverse causation would make simple inclusion of generation mix as an explanatory factor inappropriate. To avoid this apparent problem, LECG proposes to segment the sample based on the degree of regional reliance on oil- and gas-fired generation in 1990, prior to implementation of the policy changes. This criterion separates the utilities into a gas-dependent region consisting of New York, New Jersey, Delaware, eastern Maryland, and Florida, and a region with little gas dependence—Pennsylvania, western Maryland, West Virginia, North Carolina, South Carolina, Georgia, Alabama, and

Oddly given this stated concern, a subsequent section of the report acknowledges that the data actually do not show a relationship between changes in fuel mix and whether a state underwent a transition from traditional to coordinated markets (p. 29). This would seem to obviate the need for the strategy LECG employs.
Arkansas.

The following regression model is then set out:

\[ \text{Rate}_{it} = C + \text{Year}_t + \text{Utility}_i + B_1 \text{Size}_{it} + B_2 \text{Sales/Customer}_{it} + B_3 \text{Pct Industrial}_{it} + B_4 \text{Coordinated}_{it} \]

In this expression, the subscript \( i \) denotes utility and \( t \) is time. The variables are defined as follows:

- **Rate**: Average residential rate
- **Year**: A simple time trend
- **Utility**: A dummy variable to distinguish individual utilities
- **Size**: Each utility’s total retail sales
- **Sales/Customer**: Each utility’s average residential sales per customer
- **Pct Industrial**: Each utility’s percent industrial to total load
- **Coordinated**: Dummy variable for utilities in “coordinated” (i.e, LMP-based) markets

The text accompanying this model specification does not explain the rationale for including the size, average usage, and industrial load variables apart from the statement that “each of these variables is expected to have a systematic impact” (p. 14). As for the important dummy variable Coordinated, for PJM this variable is set equal to 0 for 1990-1997, 2/3 for 1998, and 1 for 1999-2004. For NYISO, it equals 0 for 1990-1998, 0.125 for 1999, and 1 for 2000-2004. While there are some possible reasons for fractional values for dummies, none is offered in this report, nor are any comparative results reported using a more conventional approach to dummy variables with values of either zero or one.

The results of estimating this model and its variations are then reported. In the basic model with dummy variables for utilities, the Coordinated variable is negative and statistically significant for gas-dependent regions, while for non-gas-dependent regions it remains negative but it falls below conventional levels of statistical significance. The authors provide no explanation for this divergence in results. Next, they replace the utility dummy variables with
each utility’s 1990 average residential rate, an alternative specification that assumes that otherwise unmeasured utility-specific differences are due only to their relative rates in 1990. Coordinated markets now matter in both cases, but now with a *larger* magnitude and significance in the case of non-gas dependence. No explanation for this instability of results is offered.

For both models, the study examines an alternative specification in which the effect of Allegheny Power is held separate in the estimation of the coefficient on Coordinated through the use of a dummy variable. This tests whether Allegheny—a new member of the coordinated market category—is appropriately included or not. The results with the separate dummy variable for Allegheny Power indicate a somewhat reduced magnitude and significance on the coefficient on Coordinated in general, but Allegheny’s own estimated coefficient is entirely insignificant. The study concludes that Allegheny does not appear to be causing much of the measured effect.

A footnote in the LECG study indicates that another econometric problem—heteroskedasticity—affects the data, possibly biasing the standard errors and significance levels (p. 27, note 29). Correction for this problem are to be found not in the text, however, but rather in Appendix C. That Appendix reports the results of two alternative correction procedures, each conducted on both the utility dummy version and the 1990 rate version of the model, each of those for three databases—the gas-dependent and the non-gas-dependent regions, and the latter with and without a dummy variable for Allegheny Power. Thus, there are now a total of 12 coefficients on the Coordinated variable reported in the various corrected specifications. It is noteworthy that in these results with the appropriate econometrics, only four of the twelve coefficients are now statistically significant.

Despite those anomalous findings, the text focuses on more favorable results. Contrary

---

7 Heteroskedasticity involves data that have a particular pattern to their distribution that is inconsistent with the assumptions of standard regression techniques. Without making corrections, use of standard regression technique gives unreliable estimates. See, for example, P. Kennedy, *A Guide to Econometrics*, 2003.
to its own evidence, it concludes simply that “all of the models yielded estimates of reductions in average retail rates arising from implementation of coordinated markets of 50 cents per megawatt-hour or more; some provided estimated savings in excess of $1.80 per megawatt-hour, while a number produced estimated savings of about $1.50 per megawatt hour” (p. 36). Moreover, the study goes on to claim that although for methodological reasons its analysis focused on residential customers, “it can be presumed that the rate impact estimate generalizes to all consumers” (p. 28). In addition, while the analysis looked only at publicly-owned utilities and cooperatives, it asserts that the estimates “should generalize” to all investor-owned utilities in RTO regions as well (p. 28). Based on these estimates of rate differentials favoring coordinated markets and these sweeping generalizations to all consumers and utilities, the LECG study concludes that customers of PJM and NYISO enjoy benefits ranging from $430 million to $1.3 billion per year (p. 36).

In the following two sections, we discuss some specific ways in which the LECG study offers some useful insights relative to existing studies, followed by a description of the study’s remaining significant flaws and limitations that ultimately undermine its conclusions.

IV. THE LECG STUDY: ONE STEP FORWARD

The LECG study is commendable insofar as it forthrightly addresses some limitations of the most common methodologies that have been used to assess the effects of restructuring. Specifically, it notes the following:

· Adjustments for the effect of fuel costs on prices may not be simple and certainly are not sufficient to control for all differences over time.

· Rate caps, stranded cost recovery charges, and other aspects of retail choice plans mean that observed rates do not represent actual market equilibrium and should not be used as the basis for evaluating reforms.

· Numerous factors, such as generation mix, vary among regions in ways that make comparisons difficult.

· Direct cost comparisons, even after adjustment for other factors, are made problematic
by the lack of price transparency and by the new, added costs of RTO operations.

· Simulation techniques are not ideally suited for calculating “but-for” prices, since simulations are designed to solve optimization problems whereas “but-for” prices are inherently the result of suboptimization.

All of these criticisms have merit, and some have profound implications for evaluations of electricity restructuring. A good example is LECG’s observations with respect to retail access (p. 9):

“The short-term rate caps, stranded cost recovery charges, provider of last resort rates, competitive retailer rates and changes in forward hedging associated with this change, make it difficult to compare average rates before and after retail access in general and make it particularly difficult to identify the long-term rate impact from the implementation of coordinated markets.”

Thus, LECG states that reliance on observed post-reform prices is invalid, since those prices are more the result of administrative adjustments and rules than they are expressions of equilibrium prices. The LECG study is notable in its recognition of this important fact. Of the nine prominent and widely cited quantitative studies discussed in the Report to the APPA, only three even acknowledge this issue and none make any adjustments to the data. Most simply ignore the effects of rate caps and treat post-reform price as a meaningful indicator of the effect of restructuring. The LECG study should be commended for pointing out that this approach is fundamentally defective.

Also noteworthy is the substantial degree to which LECG’s comments echo concerns expressed in the Report to the APPA. Both essentially conclude that existing studies all suffer from one or more methodological deficiencies ultimately rendering their findings suspect. Both recognize the need to evaluate restructuring using sounder methodologies.

V. THE LECG STUDY: TWO STEPS BACK

Although the LECG study recognizes and avoids some of the errors made in other studies, its own study is flawed by a number of significant problems. Some of the problems are methodological, including the same issues as those of other studies that LECG fails to correct,
others arise as a result of its new methodology, and yet others are candid admissions of issues that remain overlooked. Moreover, its reliance on publicly owned utilities and cooperatives as benchmark cases ignores many ways in which these utilities differ from the investor-owned utilities that dominate the industry and are the focus of reforms. We take up these issues in order.

(A) Methodological Issues

We begin by noting that the LECG study itself acknowledges some issues that it does not address. In its discussion of rate differences, the report offers the following sweeping disclaimer (p. 6, note 4):

“Average retail rates vary from year to year for a variety of reasons that are not controlled for in the study such as year to year variations in average and peak load across the regions analyzed in the study, variations in cost recovery practices across the utilities included in the study, major nuclear plant outages within the regions during particular years, variations in the duration, timing, and terms of forward hedging contracts, and differences in year to year changes in fuel costs.”

While it goes on to state that some of these issues are “intentionally not controlled for...because of the possibility that they are causally related to the implementation of coordinated markets,” no tests of the latter proposition are reported, no sensitivity analyses are conducted, and no discussion of the likely seriousness these omissions is offered. Given that this concern remains only a possibility and given that most other studies choose to include at least some of these variables, some justification for this study’s decision is in order. 8

Apart from limitations noted by LECG itself, the study has a number of other significant problems with its methodology. There are at least five types of such problems.9

(1) Like many other studies, the LECG study is not precise about what it is evaluating.

8 Another omitted issue acknowledged in the LECG study concerns changes in state taxes (p. 23). It claims that state tax increases might be captured in the coordination variable, but that would not capture changes in taxes over time in coordinated states.

9 As was done in the case of other quantitative studies, LECG was asked to provide its data so that further checks and analyses could be undertaken. LECG staff indicated that the data would be made public shortly, but that did not occur in the months before this review was finalized.
As noted above, it says that its focus is on “coordinated markets,” but according to the authors only one of the three criteria for coordinated markets—namely, locational marginal pricing—really matters. To be sure, evaluating LMP is an interesting and useful exercise, but LMP alone does not capture the full extent of reforms whose effects deserve evaluation, certainly not in a study claiming to analyze “coordinated markets.”

Moreover, an exclusive focus on LMP runs the risk that other reforms were implemented on a non-coinciding timeline, so that any effects of LMP are intermingled with other unspecified reforms that occurred around the same time. For this reason it might be preferable for the study to have included a region like California that would permit an evaluation of a coordinated market without LMP. Such a case would improve the ability to distinguish the effect of LMP from other reforms, something that is not convincingly done in this study.

(2) LECG’s progressive exclusion of most states and regions of the country results in a final analysis of a very few, and quite possibly atypical, cases. Table 1 demonstrates that by excluding ERCOT, California, the Midwest region, New England, the Western Interconnection, the TVA region, and western MISO, the study eliminates areas accounting for two-thirds of all electricity sales in the country. (Later, by examining only municipal and cooperative utilities in the remaining states, it eliminates three-quarters of the remaining sales, so that more than 93 percent of all U.S. sales are excluded.) This methodology raises several questions.

The first question is whether all these exclusions are justified. As previously noted, the exclusion of California hampers the comparison of LMP relative to other aspects of “coordinated markets.” Excluding the Western Interconnection because of hydro is not obviously necessary since other studies, including two evaluated in the Report to the APPA, preserve these observations by incorporating a variable for the percent of generation originating with hydro power. Outright exclusion of New England because it started LMP in 2003, while including Allegheny which started a year earlier, seems arbitrary. It would be better practice to determine what difference it makes to the results to include such observations with appropriate controls, rather than simply discarding them.

A further concern with these exclusions is whether the utilities that remain are representative of the much larger number that are excluded. The reason for this concern is that
the wholesale exclusions result in a focus on utilities in comparison states that do not much resemble each other. As shown in Table 2, the split between gas dependency and non-gas dependency divides states into a group of Northeastern-Mid Atlantic states plus Florida, vs. a group of Southern states plus West Virginia and parts of Maryland and Pennsylvania. Those two groups differ in a number of unexamined ways, some quite possibly important. Those differences are modest, however, in comparison with those distinguishing coordinated vs. traditional markets. The latter divide sharply along regional lines—with the traditional markets covering the southeastern states and the coordinated market encompassing New England and the mid-Atlantic—a split that raises questions about everything from economic base to weather as intervening variables. None of these issues are raised, much less resolved, in this study.

The most extreme problem arises because of the dual split in the data—dependency vs. non-dependency on natural gas, and then coordinated vs. traditional markets. This results in a breakdown of states that leaves precisely one state—Florida—in the cell for traditional and gas dependent. As a result, the comparison between traditional and coordinated markets for gas-dependent regions is essentially a comparison of Florida with most of PJM and NYISO. It is hazardous for a study to draw sweeping conclusions based on a single observation for its benchmark.

This concern is heightened by the fact that Florida’s municipal and cooperative utilities—the entire basis for this study’s comparison with coordinated gas-dependent markets—comprise only a fraction of that state’s sales, which in turn are only a small fraction of total U.S. sales. As shown in Table 1, Florida’s electricity sales represent 6.2 percent of total U.S. KWh sales, of which municipal and cooperative utilities account for 23 percent. Reliance on the resulting 1.4 percent of U.S. sales might be justified by a careful analysis of all other possible factors that might cause one observation to differ. In the case of Florida, such differences might include a per household electricity consumption that is among the highest in the country, an unusually high number of storms and power outages, a sharply constrained electric capacity since 2000, and a rapidly growing dependence on gas itself. None of these or other possible matters, however, are examined in this study. Hence, one is left with some doubt about this study’s assumption that Florida can be taken as representative of all gas dependent traditional markets.
(3) The econometric model that is set out raises a number of methodological questions. For one, electricity price data over the period 1990-2004 are used, but there is no mention or indication of a correction for inflation. Calendar years are distinguished in a manner that would pick up such a trend, but it is better practice to adjust prices directly and allow variables for calendar years to capture influences over time other than general inflation. Moreover, no real explanation is given for the three control variables that are included as explanatory variables for residential price: total retail sales, average residential sales per customer, and percent industrial load. Since there are legitimate questions about some of these, it would be important to understand the authors’ own reasoning for including these variables. Nor is any explanation given for omitting certain other variables—such as capital cost—that are often included in such regressions on electricity rates. Nor is any explanation offered for assigning fractional values to the crucial Coordination dummy variable for certain years and states. Again, it would seem incumbent on the study authors to explain this unusual treatment.

Especially troublesome questions surround the inclusion of the variable “total retail sales.” As noted, no explanation for its inclusion is offered in the LECG study, but one possible rationale might be that quantity (sales) affects price through its effect on scale economies and costs. That linkage may be true, but it is also and indisputably the case that price itself affects demand and hence sales. This dual causation means that simply including sales on the right-hand side of such an equation creates simultaneity bias in the estimates. That is, with causation in both directions, estimating the regression model as if causation were only one way distorts the estimated effects of sales and other variables on price. By itself, this problem is sufficiently serious as to undermine the reliability of the results in this study. And undoubtedly for this reason, none of the other empirical studies of price reviewed in the Report to the APPA includes sales as an explanatory variable.

A further oddity is the variable for the percent industrial load. Again, no explanation for its inclusion is offered, and its rationale is considerably less obvious. Moreover, its statistical behavior raises further questions. Its coefficient is statistically significant in 15 of 18 reported estimates, but strangely, in the utility dummy version of the model it is negative and significant

---

for gas-dependent states, but positive and significant in non-dependent states. This complete reversal of results is neither noted nor explained in the LECG study. More curious yet is the fact that in the version using 1990 prices, the exact opposite results emerge, with non-gas regions now showing a negative and significant effect of industrial load, while the gas-dependent Eastern United States has a positive (but statistically significant) effect from gas prices. The same pattern persists in the heteroskedasticity controlled versions. All in all, this instability raises questions about model specification, in particular, about causal factors that almost certainly are missing, and hence about the reliability of the reported results.

And finally among model specification issues, the LECG study excludes the price of natural gas with the explanation that it may be endogenous—that is, it may be affected by coordinated markets as it may cause electricity price differences. LECG’s alternative approach—separating gas dependent and non-gas dependent states—is said to be an appropriate control technique (p. 20), but that depends on certain assumptions. In particular, it requires that the 1990 degree of gas dependence correctly predicts its degree of dependence up to 15 years later for all reasons other than the advent of coordinated markets. But if more suitable technologies, new gas pipelines, environmental considerations, or simply demand characteristics changed, some or all of the 1990 degree of gas dependence might well have changed absent coordination, and the split sample used in the LECG study would be inappropriate. Indeed, for such reasons, most other studies prefer to include gas costs in electricity price regressions.

(4) As previously noted, the LECG study acknowledges three econometric issues that it resolves in less-than-satisfactory ways. For one, it divides its data sample into gas-dependent and non-gas-dependent states based on the stated belief that the same model might not apply to both. After the fact it examines the data and concludes that there is no basis for the distinction. At that point one would normally expect samples to be combined in order to optimize econometric results. Yet the LECG study does no such thing. Rather, it continues to use the split sample and reports only those results. The effect of combining all traditional markets and then all coordinated markets regardless of gas dependence would be of obvious interest, but one

11 Among the obvious benefits, Florida would no longer be the sole traditional market.
cannot find that in this study.

The second econometric issue concerns heteroskedasticity, a statistical problem with the data that might result in biased estimates of effects. The LECG study commendably acknowledges this problem in its data and goes on to perform the necessary corrections. Those corrections significantly weaken the results that to that point favor coordinated markets, but those new and less favorable results are reported only in Appendix C. The body of the report continues to rely upon the uncorrected results showing somewhat more significant price reductions from coordinated markets. It is difficult to conceive of an acceptable reason for this, and none is offered.

One further potentially troublesome econometric issue is acknowledged in Appendix A. There the study notes that a few utilities constituted outliers in the overall results (p. A-3), altering the magnitudes and statistical significance of the estimated effects of coordination. Only one set of results are presented, however, so that it is impossible to determine exactly how sensitive the results may be to these data anomalies.

As a result of these and other econometric issues, the LECG study relies on many estimated coefficients that fall short of conventional levels of statistical significance, and others that are unstable from specification to specification. Indeed, its key result— that “all of the models” show that coordinated markets reduce retail rates by an amount between $.50 and $1.80 per MWh—should be qualified by noting that many of those estimates are not significantly different from zero. That is, in a statistical sense they cannot be distinguished from the possibility of no effect at all.

(5) The LECG study relies on three sweeping but completely unsupported presumptions. First is the implicit assumption discussed above that the chosen states (or in one case, just a single state) accurately represent all states with particular types of market and degrees of gas dependence. But the study goes on to grander claims yet.

The second assertion is that its results for residential customers generalize to all commercial and industrial users. The sole justification offered for this statement is that, “absent reason to believe” the contrary, “it may be presumed” to be true (p. 28). There is no indication of an effort to identify any basis for this presumption. Moreover, this extension of results to
commercial and industrial users is ironic since elsewhere this same report claims that only residential customers are sufficiently homogeneous to be treated as a group. Now, apparently, not only are industrial and commercial users judged sufficiently similar among themselves, but also similar to residential customers.

The study’s third sweeping presumption is that its quantitative results extend to all consumers regardless of the type of utility that serves them. Once again it states that absent reason to believe the contrary, the effects of coordinated markets on municipal and cooperative utilities, however measured, “should generalize to all consumers...whether served by public utilities or investor-owned utilities” (p. 28; emphasis added). Again, the study offers no basis whatsoever for this assumption. We shall discuss this issue in greater detail in the next section.

(B) Municipal and cooperative utilities

The LECG study takes municipal and cooperative utilities as its benchmarks since they represent utilities with an unchanged obligation to serve their customers and that operate both in coordinated markets and in traditional markets. Hence, it is claimed, the difficulties associated with controlling for retail access are avoided while preserving the applicability of the results to the investor-owned utilities that dominate the industry and are the focus of market reforms. Given this crucial methodological role for municipal and cooperative utilities, there is remarkably little discussion of them in the LECG study. There is no indication of a serious effort to understand their characteristics and operations, or the myriad ways in which municipal and cooperative utilities differ from IOUs and indeed, even between themselves.\footnote{The sole mention of any consultation by the authors concerns assignment of municipal utilities and co-ops to various sub-regions, for which the report states it was advised by PJM (p. A-1).}

Not all differences are necessarily relevant, of course, but the following characteristics of municipal and cooperative utilities raise serious questions about their possible effect on the conclusions of the LECG study:
Perhaps most obviously, municipal and cooperative utilities are non-profit enterprises. Their pricing practices, price-cost margins, and responses to cost changes do not fully correspond to those of ordinary profit-making firms.\(^\text{13}\) For this reason alone using the experience of municipal and cooperative utilities to predict the behavior of investor-owned utilities would seem hazardous if not altogether inappropriate.

Muni accounting does not fully correspond to that used by IOUs, since municipal utilities are not financially entirely independent of their city or town governments. While the evidence suggests that municipal utilities generally operate efficiently, there are cost items such as flows of capital and services between municipal utilities and their governments that are unique to such utilities. Whether or to what extent these affect interpretation of data are important questions nowhere raised by the LECG study.

Municipal utilities generally do not behave identically to co-ops. The former are publicly owned with public controls and governance mechanisms,\(^\text{14}\) whereas co-ops, as their name implies, are cooperatively owned with quite different oversight and operations. There is no indication in the LECG study that these differences are understood, and indeed, the study refers to both as “public” even though co-ops are private enterprises (pp. 18, 25, 27, 28, etc.). By constructing a sample consisting of both municipal and cooperative utilities, the LECG study introduces statistical errors of an unknown sort.

Municipal and cooperative utilities are very numerous but generally much smaller than investor-owned utilities. There are roughly 900 cooperatives and 2,000 publicly owned utilities in the United States, compared to about 220 IOUs, although collectively municipal and cooperative utilities account for only about 25 percent of total KWh sales. Well into the 1990s, the latter were less vertically integrated (i.e., owning and operating generation, transmission, and distribution facilities) than IOUs and instead more focused on distribution and sales to end users. At present, many IOUs have divested their generation, while municipal utilities have retained


whatever generation they owned. All of these enormous differences in size, structure, and focus plausibly affect their current operations and responses to reforms.

None of these issues are mentioned in the LECG study. It appears to have simply assumed the co-ops and municipal utilities represented a convenient natural experiment for the effects of restructuring and employed data without considering the fundamental differences among these utilities. The LECG’s lack of understanding of muni and co-op operation can be illustrated through a number of specific examples from the study’s discussion:\(^{15}\)

(1) There are substantial differences in the oversight of municipal and cooperative utilities in different states, even though the LECG study claims that all are subject to the same regulation, or at least obligation to serve. In Delaware and New Jersey, for example, publicly owned electric utilities are not rate regulated, but Florida regulates their “rate structures” but seemingly not their level. In Maryland publicly owned utilities are rate regulated. In New York municipal systems are rate regulated if (but only if) they are 100 percent requirements customers of the New York Power Authority. And in all these states, cooperatives are rate regulated.\(^{16}\) Clearly, no common regime applies to all these cases that the LECG study assumes to be identical.

(2) Publicly-owned power systems have preferential access to low cost hydro generation from federal power projects. This source affects New York’s publicly owned utilities to a much greater degree than Florida’s public systems, in amounts that change annually. The LECG study does not examine the extent to which lower prices in New York during the period of coordinated markets might be simply the result of the changing mix of preference power vs. sales reflecting market prices.

(3) Along the same lines, divestiture of generation has left IOUs more exposed to market prices of power supply over the past five to ten years. To the extent that municipal utilities may

\(^{15}\) See H. Spinner, “A Response to the November 20, 2006 Draft PJM ‘Supported’ Study by LECG,” Virginia SCC, December 13, 2006. Some of these points are made in Spinner and in Christensen Assoc.,”Review of LECG Analysis of Coordinated Markets,” memo to NRECA, December 19, 2006

\(^{16}\) This information was provided by APPA. Where municipal utilities are not regulated, they are still subject to local governmental rate oversight. As has been documented (Kwoka, 2002), that can take several forms as well.
now have a greater proportion of power from internal generation plus long-term supply contracts, the LECG study’s finding with respect to municipal utility prices may reflect longstanding contractual commitments rather than current market reforms.

For all these and other reasons, the relationship between wholesale market operation and retail price for municipal and cooperative utilities is not identical to that for investor-owned utilities in other respects. The LECG study fails to recognize these differences. It does not demonstrate any real understanding of municipal utilities or co-ops, even though it uses them for its benchmark comparison and extrapolation to all other utilities. Neither its analysis nor that extrapolation is well founded.

V. CONCLUSIONS

We can now evaluate the LECG study against the criteria set forth in the Report to the APPA of November 2006 -- criteria that have already been used to judge twelve other studies.

(1) Defining electricity restructuring. The LECG study states that it is interested in evaluating what it terms “coordinated markets,” a term that suggests reforms considerably narrower than restructuring overall. There are three deficiencies to its stated focus. First, the LECG study is inconsistent in its definition of coordinated markets. As noted earlier in this review, while it initially gives three criteria, in practice these seem to devolve into only locational marginal pricing, but this is ultimately unclear. Secondly, assuming it intends to assess LMP, the LECG study does not explain why it believes it has successfully disentangled the effects of other reforms that occurred around the same time in various states and regions. And thirdly, even as a study of LMP, the LECG study presumes that reform occurred at a single point in time, specifically that defined by the implementation of the RTO.

17 Among other reasons, Christensen Associates contend that in the absence of reforms the high costs in New York might well have declined anyway. They also note the curious fact that LECG finds an identical price effect for NYISO in 1999 when LMP was in effect for only two months, as for the full year 2000. Spinner notes that absent regulation lower costs might not have translated into lower prices anyway. These points constitute valid further concerns about the LECG study.
(2) Post-reform price. The LECG study rejects the approach of interpreting post-reform price as an indication of the effects of reform. In particular, it notes that rate reductions and freezes, stranded cost recovery charges, and other factors preclude such an interpretation. In these respects, the LECG study deserves commendation, since most other studies ignore this fact. That said, its own method for avoiding these problems in its evaluation of reforms encounters several other serious problems. These include the small number and select group of states used for comparison, econometric issues that are addressed in inadequate ways, some control variables that behave strangely in the regressions, the absence of controls for fuel costs, plus a list of unresolved issues that the study itself acknowledges in a footnote. All of these represent cautions concerning the methodology of the LECG study.

(3) Causation. The LECG study makes some questionable judgments in defining its sample and some serious errors in attributing causation. With respect to sample selection, LECG makes sweeping exclusions of states and utilities, not always fully explained and resulting in a very small and select subset of observations. From an estimation perspective, by including sales quantities as an explanatory variable for price, it introduces the econometric problem of endogeneity, biasing the results. Even apart from all other limitations of its study, this problem would prevent any straightforward interpretation of the coefficients in its regressions. In addition, the study is inadequately concerned with the statistical significance of many of its results, and without an adequate level of significance a coefficient cannot be interpreted as a reliable indicator of the relationship that it is testing. And finally, the study makes altogether unsupported assumptions about the applicability of its findings to all types of customers and all types of utilities. There is simply no evidence provided for the presumptions that underlie these conclusions, and much evidence that they may not hold.

Apart from failing these three criteria, the LECG study has a very mixed record with respect to the three areas indicated in the Report to the APPA as generally receiving too little attention in most studies. These are as follows:

(1) Market structure, market power, and mergers. Whether coordinated markets affect consolidation, unilateral withholding, and mergers in this industry are not mentioned at all in the LECG study.
(2) RTO costs, governance, and effectiveness. The LECG study contends that the all-in prices that it is using for comparison include all RTO costs. It is correct that current RTO costs are included, but this fails to address the fact that RTO costs are expected to increase in all regions as additional institutions and procedures are put into place. In addition, neither the governance issues nor the effectiveness of RTOs is addressed.

(3) Service quality and reliability. The possible effects of reform on service quality and reliability are not mentioned at all in the LECG study.

In summary, the LECG study is noteworthy in that it recognizes certain problems that have invalidated other quantitative studies. Perhaps most important is the fact that using simple post-reform prices as indicators of the effects of reforms is methodologically incorrect and leads to unreliable results. But in its own empirical work, the LECG study falls victim to repeated errors of other types. As documented in this review, the study makes errors in its understanding of municipal and cooperative utilities, errors in excluding data points and relying on others, errors in model specification, errors in its estimation procedure, and errors in extrapolating its results to utilities and customers that clearly differ.

For all these reasons, the LECG study does not employ sound empirical methodology and its conclusions should not be relied upon in evaluating the restructuring of electricity markets.
<table>
<thead>
<tr>
<th>State</th>
<th>State Share of US Sales, All Sectors</th>
<th>Public Power's State Share of Total State Sales</th>
<th>Cooperatives State Share of Total State Sales</th>
<th>PP + Coops State Share of Total State Sales</th>
<th>PP + Coops State Share of Total US Sales</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alabama</td>
<td>2.4%</td>
<td>18.5%</td>
<td>12.2%</td>
<td>30.7%</td>
<td>0.7%</td>
</tr>
<tr>
<td>Arkansas</td>
<td>1.3%</td>
<td>12.8%</td>
<td>26.1%</td>
<td>38.9%</td>
<td>0.5%</td>
</tr>
<tr>
<td>Delaware</td>
<td>0.3%</td>
<td>14.9%</td>
<td>9.1%</td>
<td>24.1%</td>
<td>0.1%</td>
</tr>
<tr>
<td>Florida</td>
<td>6.2%</td>
<td>15.6%</td>
<td>7.9%</td>
<td>23.5%</td>
<td>1.4%</td>
</tr>
<tr>
<td>Georgia</td>
<td>3.6%</td>
<td>9.1%</td>
<td>27.9%</td>
<td>36.9%</td>
<td>1.3%</td>
</tr>
<tr>
<td>Maryland</td>
<td>1.9%</td>
<td>1.1%</td>
<td>6.2%</td>
<td>7.4%</td>
<td>0.1%</td>
</tr>
<tr>
<td>North Carolina</td>
<td>3.5%</td>
<td>12.1%</td>
<td>12.6%</td>
<td>24.7%</td>
<td>0.9%</td>
</tr>
<tr>
<td>New Jersey</td>
<td>2.2%</td>
<td>1.5%</td>
<td>0.2%</td>
<td>1.7%</td>
<td>0.0%</td>
</tr>
<tr>
<td>New York</td>
<td>4.1%</td>
<td>16.6%</td>
<td>0.1%</td>
<td>16.8%</td>
<td>0.7%</td>
</tr>
<tr>
<td>Pennsylvania</td>
<td>4.1%</td>
<td>1.0%</td>
<td>1.7%</td>
<td>2.7%</td>
<td>0.1%</td>
</tr>
<tr>
<td>South Carolina</td>
<td>2.2%</td>
<td>19.1%</td>
<td>17.9%</td>
<td>36.9%</td>
<td>0.8%</td>
</tr>
<tr>
<td>West Virginia</td>
<td>0.8%</td>
<td>0.2%</td>
<td>0.3%</td>
<td>0.6%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Total</td>
<td>32.6%</td>
<td>Total</td>
<td>Total</td>
<td>Total</td>
<td>6.8%</td>
</tr>
</tbody>
</table>
## TABLE 2

**Distribution of States in LECG Study**

<table>
<thead>
<tr>
<th>Gas Dependent</th>
<th>Coordinated</th>
<th>Traditional</th>
</tr>
</thead>
<tbody>
<tr>
<td>New York</td>
<td>Florida</td>
<td></td>
</tr>
<tr>
<td>New Jersey</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Delaware</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Maryland (eastern)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Non-Gas Dependent</th>
<th>Coordinated</th>
<th>Traditional</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pennsylvania (eastern)</td>
<td>Alabama</td>
<td></td>
</tr>
<tr>
<td>West Virginia</td>
<td>Arkansas</td>
<td></td>
</tr>
<tr>
<td>Maryland (western)</td>
<td>Georgia</td>
<td></td>
</tr>
<tr>
<td></td>
<td>North Carolina</td>
<td></td>
</tr>
<tr>
<td></td>
<td>South Carolina</td>
<td></td>
</tr>
</tbody>
</table>