PUBLIC VS. PRIVATE OWNERSHIP AND ECONOMIC PERFORMANCE: EVIDENCE FROM THE U.S. ELECTRIC POWER INDUSTRY

by

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I. INTRODUCTION

One of the more remarkable industrial phenomena of the past decade has been the worldwide movement toward privatization of state-owned enterprises. Privatization policies have been pursued for numerous specific reasons, but at the core of most is the belief that private ownership delivers superior performance—that is, costs and prices closer to the competitive norm. This paper tests that belief by examining the actual performance of privately owned electric utilities in the United States relative to their publicly owned counterparts. The evidence shows that it is public—not private—ownership that results in superior price and cost performance. The reason for this finding has been anticipated in some recent literature: For natural monopolies, public ownership and regulated private enterprise represent alternative governance structures, each imperfect in its own way. In the present case, it is regulation that creates significantly larger cost and price distortions. These results emphasize the importance of careful specification of the alternative to public ownership in the policy debate.

The U.S. electric power industry is well-suited for examination of these issues: Although the most familiar segment of the industry consists of large integrated monopolies, in reality this describes less than 10 percent of the 3000 electric utilities. About 2000 are publicly owned systems, the balance consisting of rural electric cooperatives and a handful of federal hydro power projects. This diversity has led to a number of previous studies of cost and price differences among these utilities. The absence of consensus in these studies is reflected in two recent summaries. Boardman and Vining (1989) survey studies from several industries and conclude that "existing empirical evidence...provides weak support for [the] hypothesis" that "public
enterprises...perform less efficiently." Focusing on electric utilities, Peters (1993) by contrast states that "the evidence indicates quite strongly that there is either no statistically significant difference between non-profit [i.e., publicly owned] and for-profit electric utilities, or that non-profit utilities in fact outperform for-profit utilities."

This study differs from most past work in this area in three significant ways. First, it specifies an explicit model of utility cost, pricing behavior by the regulator or public controller, and demand conditions. This formulation allows price and cost to be simultaneously determined and each to differ by ownership mode. By contrast, most previous studies have focused upon either cost differences or price differences, and existing price studies tend to be fairly ad hoc. Simultaneous equations estimation shows that public ownership is associated with lower production costs and, moreover, for given unit cost, price is significantly lower as well.

The second significant feature of the analysis is a disaggregated version of the model into residential, commercial, and industrial segments. Theory suggests that public ownership will be sought by a politically powerful constituency in order to extract available rents. Residential customers--in their roles as voters--are the constituency that typically seeks public ownership, and the evidence in fact shows that they are its major beneficiary. Commercial customers secure a modest benefit, whereas industrial users face comparable final prices under public and private ownership.

In addition to the explicit modeling and disaggregation, the third noteworthy feature of this research is the comprehensive and detailed nature of the underlying data. The data base has its origins in a major expansion (as of 1986) in the number of publicly owned utilities for which the
Department of Energy collected data comparable to those for privately owned utilities. The need for such data is underscored by the large number of factors that have previously been found to influence cost and price performance of electric utilities. These include utility size, degree of vertical integration, type of generating plant, affiliation with other utilities, mix of customer types, capital costs, tax status, fuel costs, power purchase costs, and even the possible existence of a competitive supplier.

All these and other factors are fully accounted for by the data and model utilized in this study. The above-stated conclusions are therefore not artifacts of often omitted variables. In addition, light is cast upon other questions of intrinsic interest about the electric power industry. For example, there is clear evidence of cost advantages from vertical integration, in the sense of a utility generating more of its own power requirements. Membership in major holding companies is strongly associated with lower costs, whereas other affiliations appear to result in no benefit. Interestingly, the degree of competition faced by any particular electric utility is not associated with lower costs or prices.

The remainder of this paper is structured as follows: The next section provides further background into the issues and facts concerning the electric power industry. Sections III presents the model and results of the analysis of the overall market, while Section IV analyzes market segments. Section V summarizes the findings and their implications for theory and for policy.

II. ISSUES AND DATA BACKGROUND

Although the influence of public ownership on firm behavior and performance has been the subject of long and at times heated debate,
economists have formalized the issues only fairly recently. There are three identifiable strands to the relevant literature—property rights theory, information asymmetry, and agency theory. First, Alchian and Demsetz (1972), DeAlessi (1974), and Peltzman (1981) have argued a property rights view, noting that public ownership makes transfer of ownership claims—which inhere in residency—prohibitively expensive. That in turn diminishes control over the management of those entities, leaving publicly owned utilities less constrained from pursuing non-economic objectives. These authors offer some evidence of differences in price levels and price structure that are said to reflect such greater discretion under public ownership.

This property-rights view, however, does not reflect the fact that in practice private utilities are generally subject to regulation with its own set of imperfections. In their analyses of the choice between public ownership and private regulated firms, Shapiro and Willig (1990) and K. Schmidt (1993) emphasize the informational disadvantages faced by a regulator seeking to ascertain costs and establish prices. Public ownership is said to remedy, or at least alleviate, this fundamental asymmetry by providing direct access to and control of the firm's information base. Accounting techniques, audits, and oversight serve to better inform the public owner relative to the regulator, so that the public owner can secure the informational surplus and put it to his/her desired ends.

The third and most recent approach is based on agency theory. In the formulation due to Laffont and Tirole (1993),¹ contract incompleteness results in suboptimal investment by the manager of a publicly owned firm in those types of assets that can later be expropriated by its public owners. This investment distortion results in productive inefficiency under public

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ownership. But the manager of a regulated private firm also has weakened efficiency incentives, due to the existence of two principals—the owner and the regulator. In response to this, the regulator may tolerate some measure of allocative inefficiency in order to achieve superior productive efficiency.

Theory has therefore noted imperfections in both public ownership and regulated private ownership—different imperfections, and without strong priors concerning their relative magnitude. Concurrently with the development of theory, some performance measures have been subjected to empirical investigation. Perhaps the most extensive literature involves cost function estimation, mostly relying upon the translog and other flexible functional forms and typically focusing on steam power generation. Contrary to the predictions of property-rights theorists, these studies more often than not find lower costs from publicly-owned utilities. This result has often been attributed, however, to three advantages of publicly-owned electric utilities: (a) greater access to low-cost hydro power as a result of their first claim on federal hydro sources, (b) lower cost of capital, the result of tax-exempt bond financing, and (c) exemptions from most federal and state taxes (Peltzman; Joskow and Schmalensee, 1985; Putnam, Hayes, and Bartlett, 1985). Others, however, have noted offsetting factors. For example, the actual tax burden of privately-owned utilities is less than the apparent tax rate as a result of accelerated depreciation and the investment tax credit.

Whatever these cost studies show, of course, they do not necessarily resolve the question of the relative price of power supplied by the two kinds of utilities. After all, lower costs may or may not be passed through to prices by the ultimate decision-maker, be that the utility owner, manager, or regulator. Indeed, the agency theory formulation implies that full pass-
through may not even be intended by the regulator. Perhaps confirming this, those studies that have at least indirectly examined utility prices have found pricing inefficiencies under regulated private ownership that are often greater than under public ownership.⁴

A few comments are in order on two other major structural features of the electric power industry likely to be related to performance and examined in this study. Economies of vertical integration between generation and the transmission/distribution stage have been extensively discussed due to their importance to the policy of deintegrating traditional utilities (e.g., Joskow and Schmalensee (1983)). The only direct evidence on this issue—due to Henderson (1985) and Kaserman and Mayo (1991)—suggests a cost penalty for electric utilities that only generate or only distribute power relative to those that are integrated into both functions.

With respect to competition, about sixty jurisdictions in the U.S. are served by two local electric utilities where customers may have at least some opportunity to choose between alternative suppliers. Studies by Primeaux (1977, 1985) conclude that such utilities achieve lower costs than monopoly companies and that resulting residential prices are much less.⁵ While the underlying data, approach, and interpretation in these studies have been subject to criticism (see Joskow and Schmalensee), these results at least underscore the possibility of significant differences due to competition.

Clearly, then, an extensive empirical literature exists examining questions about public vs. private ownership and other influences on utility performance. The ability of this literature to answer the core questions about relative performance, however, has been limited by the prevailing focus on costs rather than costs and prices, on the costs of power generation
instead of all stages of production, and primarily on steam generation costs at that. In addition, these studies vary widely in the degree to which they control for other factors, and none has considered the possibly simultaneous effects of ownership, vertical integration, and competition. The data and modeling in this study seek to remedy these various limitations and thus answer the core questions more definitively.

The data set here utilized consists of 543 electric utilities in the U.S. in 1989. As shown in Table 1, 147 of the 543 utilities are privately-owned, often termed "investor-owned utilities or simply "IOUs." These account for 98 percent of total IOU sales in that year. The remaining 396 are publicly-owned systems comprising 83 percent of sales by public utilities. In addition, 306 of the total of 543 utilities engage in at least some generation of power--141 of the IOUs and 165 of the publicly-owned systems. Ninety-four utilities face a "competitor" somewhere in their service territory, although whether any actual competition results is an open question. Forty-five of the 147 IOUs operate wholly or partially in jurisdictions where utility commissioners are elected instead of appointed. Lower prices, at least for important constituent groups, might be expected in those places. Thirty-three IOUs are members of multistate "registered" holding companies and another 20 belong to smaller, intrastate "exempt" holding companies. Fully 160 of the publicly-owned utilities belong to joint action agencies, more limited cooperative ventures.

This summary table confirms the common observation that IOUs are on average considerably larger than publicly-owned utilities (e.g., Fare, p. 97). The average MW (MWh) of IOUs is more than fifteen times as large as for publicly owned systems and their total number of residential, commercial, and
industrial customers (CUSTOT) is nearly twenty times as large. Transmission miles and distribution miles (neither reported here) show similar differences. Furthermore, IOUs are much more vertically integrated. The proportion of a utility's electricity sales represented by its own power generation (GEN/MWH) averages 74 percent for IOUs, compared to only 17 percent for publicly-owned systems.\footnote{These data, of course, refer to differences in utilities' underlying characteristics, ultimately to be related to measures of performance. Table 1 also reports the latter: The average price of all electric power sold (PRAVG) by IOUs is significantly larger than power sold by publicly-owned utilities. The difference—.0044 per kwh—is fully 7.4 percent of average price. Among customer classes, IOU prices are significantly greater for both residential and commercial customers (PRRES and PRCOM, respectively), while the price to industrial customers (PRIND) is identical. Regarding costs, the average overall cost of operations (AVGCOST) is virtually identical for publicly owned and privately owned utilities. This masks significant differences among the components of overall costs, as evidenced by the higher costs of power supply (production plus purchases, denoted ACSUP) by publicly owned utilities, but their lower overhead costs (customer, sales, and administrative costs, labelled ACOH).

Some possible explanations for these cost and price differences are shown in the third block of this table. Hourly wage costs (WAGE) are significantly less for publicly-owned utilities, although nuclear fuel costs and the price of purchased power (PRNUCFU and PRPOWER, respectively) are not different, and the steam fuel cost (PRSTEFU) actually appears to be greater. Substantial differences emerge for capital costs and tax rates. The}
conventional weighted average cost of common stock, preferred stock, and long-
term debt (denoted CCPD) is 7.1 percent overall, but fully 8.1 percent for
IOUs vs. 6.7 percent for publicly-owned systems. A broader and preferable
measure includes certain essentially interest-free capital items unique to
publicly owned utilities (see Data Appendix for details). Under this COSTCAP,
the capital cost for publicly-owned systems falls to 4.8 percent. Under
either definition, the differences are statistically significant.

Measures of effective tax rates and other mandated flows show a similar
pattern. TAXR comprises all conventional tax payments by utilities plus
"payments in lieu of taxes" made by publicly owned systems and certain minor
technical adjustments to IOU taxes (see Data Appendix), expressed as a rate
per kwh. The broad exemption from direct taxation results in a much lower tax
rate for publicly owned utilities. But since many public systems also provide
contributions and services to their municipality, receive them from the
municipality, or both, the net flow of these may be construed as mandated
costs analogous to tax payments. TAXCSR adds these net contributions and
services to tax payments, resulting in a narrower—but still sizeable and
significant—gap between publicly owned systems and IOUs.

Clearly, many factors differ between privately owned and publicly owned
systems. Equally obviously, these simple comparisons do not establish
whether—or to what degree—such factors are actually responsible for observed
price and cost differences. That question requires an appropriate model to be
brought to bear on the data. It is that modeling issue to which we now turn.

III. AGGREGATE MODEL AND RESULTS

The model employed here is rooted in the specific behavioral processes
that underlie cost and price decisions by publicly owned and privately owned electric utilities. The behavior of regulators/controllers regarding price, of firms with respect to their costs, and of consumers regarding quantities are all represented. Since price and cost behavior may differ between publicly owned and privately owned utilities, the model is explicitly designed to test for these possibilities and to measure any effects that emerge.

At a first approximation it can be assumed that both types of utilities are allowed to recover full costs, i.e., to price at the breakeven point of average cost. In the case of a privately owned utility, this objective is pursued by the regulator, whereas for publicly owned utilities, a manager or public controller presumably strives for at least approximately breakeven operation, but perhaps other objectives as well. These considerations imply a model in which price is a function of the utility's average cost of operation and, of course, ownership mode.  

\[ P_{\text{Ravg}} = f(\text{AVGCOST}, \text{PUBLIC}, X) + \varepsilon \]  

(1)

In this equation, PUBLIC a dummy variable taking on a value of one for publicly owned utilities, X a vector of other possible influences, and \( \varepsilon \) a random error term.

In the empirical specification, AVGCOST is simply a transformation of (endogenous) total cost and quantity, while the vector X includes TAXCSR as an exogenous cost term to reflect total taxes, contributions, and services extracted from or by the utility. Other exogenous variables include PCTCOMP, which measures the extent of "competition" as the percent of a utility's customers for which it faces a retail distribution competitor, plus ELECT, a dummy variable denoting those IOUs operating in states where public utility commissioners are elected. Additional dummy variables are included for
registered holding companies, the most extensive and potentially significant form of integration and coordination (HCREG); less potent "exempt" holding companies (HCEX); and joint action agencies, limited cooperative ventures strictly among publicly owned systems (JAA). These serve to test whether any of these features alter the relationship between cost and price.

The second equation is simply the demand function faced by the utility:

\[
\text{MHW} = g(\text{PRAVG}, R, Y) + \eta 
\]

Here other relevant prices are denoted as R, and demand shifters by Y, with \( \eta \) the error term. The other prices relevant to demand are those for the major substitute fuel, natural gas, which should enter the demand equation for electricity with a positive sign. RESGASPR, COMGASPR, and INDGASPR represent natural gas prices for residential, commercial, and industrial users, respectively. Also included are the numbers of each type of customer—residential (CUSTRES), commercial (CUSTCOM), and industrial (CUSTIND). Residential and commercial power consumption each exhibit some income elasticity (Taylor (1975)), which should be captured by disposable income per capita INCPC. Demand is also expected to be positively influenced by cooling degree days (COOLDAY) and heating degree days (HEATDAY) in each utility's area.

The third behavioral equation is a total cost function of the form:

\[
\text{TOTCOST} = h(\text{MHW}, \text{PUBLIC}, \text{GEN}, W, Z) + \nu 
\]

In this equation, total costs TOTCOST vary with quantity sold, public ownership, the amount of power generated GEN, factor costs W, other cost shifters Z, and an error term. As before, PUBLIC will capture any cost differences due to public ownership, while GEN controls for the size of a utility's generation operations (more on this below). For generating
utilities, the percentages of capacity comprised of nuclear, hydro, and "other" (CAPNUC, CAPHYD, CAPOTH) are incorporated. These allow generation costs to differ depending upon the degree of reliance upon nuclear facilities, low-cost hydro plants, and high-cost peaking units (the "other" category), all relative to conventional steam generation.\textsuperscript{11}

Among other variables, steam fuel cost per steam-generated kwh (PRSTEFU), nuclear fuel cost per nuclear-generated kwh (PRNUCFU), the price per kwh of purchased power (PRPUR), local wage data (WAGE), and the cost of total capital (COSTCAP) are all included. Also, a variable for the size of transmission network (transmission pole miles, TRANMI) allows for possible scale effects in that function.\textsuperscript{12} Finally, a series of dummy variables that distinguish among the nine NERC regions is included to pick up any otherwise unmeasured sources of cost differences.

Equations (1), (2), and (3), together with certain identities, represent a simultaneous equation system in price, quantity, and cost. This system is estimated on data for 543 utilities using instrumental variables techniques, in this case equivalent to two-stage least squares. A linear form for the model is dictated by the structure of the data, specifically, by the existence of a number of factors that play no role (and hence take on zero values) for subsets of the observations. For the pricing and demand equations above, the linear form is straightforward and obvious. The explicit form of equation (3), the cost function, however, is worth writing out as:

\[
\text{TOTCOST} = a_0 + a_1 \text{W\textsuperscript{2}} + a_2 \text{W\textsuperscript{2}} + a_3 \text{GEN} + a_4 \text{GEN}^2 + a_5 \text{W\textsuperscript{2}} \text{GEN} \\
+ a_6 \text{PUBLIC} + a_7 \text{W} + a_8 \text{Z} + \pi
\]

(3')

This quadratic form is reasonably flexible with respect to quantity distributed and quantity generated, and in addition neatly captures the cost
implications of vertical integration in the term MWH*GEN. Since costs rise directly with both MWH and GEN, the interaction between them represents the incremental costs of more extensive joint provision. A positive coefficient $a_3$ would therefore imply higher total costs from generation-plus-distribution relative to the same quantities being separately provided.\footnote{13}

Despite these attractive properties, quadratic cost functions do have one major limitation: They are not linearly homogenous in input prices, and the present version is also incomplete in its allowance for cross-product effects. Completeness, however, results in an unmanageable number of highly correlated terms, a large fraction of which are endogenous in this model. Interpretation and indeed estimation itself become difficult under these circumstances. We therefore employ the form given in equation (3'), finding that it performs quite well, consistent with comparable previous work.

The results of estimating this model are reported in the blocks of Tables 2, 3, and 4 labelled "Aggregate Model." Column (a) of Table 2 begins with a baseline regression of the total cost function focusing strictly on output and input cost determinants, i.e., without distinctions for ownership, competition, and interfirm affiliations. All but three variables (WAGE, CAPHYD, and CAPOTH) are of the expected sign and highly significant. Taken together, the coefficients on MWH and MWHSQ imply initial economies in electric power distribution and sales, but ultimately in the range of observation, rising costs. By contrast, total costs are strictly convex in power generated (GEN and GENSQ) throughout. These results are broadly consistent with the absence of important scale economies in generation, while distribution remains a natural monopoly across a wide range of output.

Apart from scale effects, this equation also tests for vertical
economies. The negative and significant coefficient on the interaction term MWH*GEN implies that those utilities that both generate and distribute power have significantly lower costs relative to those that only engage in little or no generation.\textsuperscript{14} This result—robust throughout all specifications—confirms other findings of cost efficiencies associated with vertical integration (e.g., Kaserman and Mayo).

Other variables perform largely as expected. Higher prices for steam fuel, nuclear fuel, and purchased power all increase utility costs, the first two significantly so. Wage appears with a negative sign, but is statistically insignificant.\textsuperscript{15} Capital costs are positively and nearly significantly (7.5 percent in a one-tail test) related to total costs, a finding consistent with the importance of this input and its difference between utility types. Utilities that rely upon nuclear generating capacity incur significantly higher costs, whereas dependence upon hydro and other capacity do not emerge as important explanators.\textsuperscript{16} There is evidence of scale economies in transmission, with TRANMI negative and significant. Finally, a series of regional dummy variables is included, but they are collectively insignificant. The Wald test statistic of 8.80 is far short of the cutoff value.

The equation reported in column (a) seems to fit the data quite well, with overall $R^2$ of .88. To examine the central issues of this study, variables for public ownership, competition, and membership in holding companies and joint action agencies are included in the column (b) specification. With the exception of CAPHYD (insignificant throughout), all variables hold their signs and most are very similar in magnitude. Thus, the same conclusions apply as previously found with respect to scale economies in distribution, their more limited role in generation, and vertical economies.
between the two stages.

Regarding the key new variables, public ownership emerges as significantly associated with lower costs of production, as evidenced by the t-value of 3.53 on the dummy variable PUBLIC. The magnitude of the estimated coefficient implies that public ownership reduces total costs of otherwise comparable IOUs by 2.3 percent. Given the comprehensive controls in the model, this difference cannot be due to size, vertical integration, type of generating capacity, or other such features of utilities, nor to any "artificial" advantages of public ownership, such as capital costs or hydro power preference. Rather, the explanation would appear to be the relative inefficiency of the alternative governance structure, namely, regulation of privately owned enterprises.

Public ownership, however, is the only one of the additional variables which proves to be at all important in determining total costs in electric power. The measure of competition PCTCOMP is actually positive whereas HCREG, HCEX, and JAA have varying signs, but are all statistically indistinguishable from zero. There is no evidence here that competition as it exists in these markets—which is relatively muted—nor any form of interfirm affiliation—registered holding company, exempt holding company, joint action agency—is an important influence on costs.

Membership in registered holding companies deserves further attention since these entities may integrate certain operations and account for them in ways that render subsidiary cost data suspect. To be certain that their inclusion does not distort the results, column (c) reruns the model without such member companies. This reduces the number of observations by 33, for a total of 510. As is readily seen, this makes no difference in any of the
variables of interest. In particular, both the coefficient and the t-statistic on PUBLIC are nearly identical, so that the measured effect of public ownership is not an artifact of an inappropriate comparison involving registered holding companies.\textsuperscript{17}

Finally, since publicly owned and privately owned utilities differ in average size, the shift term PUBLIC may not completely capture the nature of cost differences between the two types. Column (d) adds the interaction term PUB*MWH, defined as PUBLIC multiplied by MWTOT, to the regression reported in column (b). Again, all other variables are robust to this change in specification. The coefficient on PUB*MWH itself emerges with a negative sign, indicating a widening cost differential with the size of a publicly owned utility, and takes over a good bit of the statistical significance previously concentrated in PUBLIC. High collinearity now reduces the magnitude and t-value on the estimated coefficient for PUBLIC, although it remains negative. A Wald statistic for the joint significance of PUB*MHW and PUBLIC indicates that the two variables are highly significant, at better than 99 percent, confirming the continued association between public ownership and lower costs. At mean values, the effect of public ownership is now 2.2 percent of total costs.

Turning to the demand equation for this model, the estimated results are presented in the "Aggregate Model" block of Table 3. As is evident, quantity demanded is strongly and negatively influenced by price PRAVG, with a t-statistic in excess of 8.00. The estimated coefficient implies a demand elasticity (in absolute value terms) at mean price and quantity of 1.95, which is at the high end of the range of reported estimates in the literature (Taylor).
Among other variables, the numbers of residential and industrial customers in the service area strongly increase demand, with the role of commercial customers probably obscured by collinearity. Collinearity also affects the estimated coefficients on natural gas prices, with the expected positive effect only for commercial gas price, and insignificant estimates for the other two categories. Demand is also clearly greater where climate-based power requirements (COOLDAY and HEATDAY) are greater. Finally, larger disposable income shifts demand outward, although the t-value on INCPG falls short of conventional statistical significance.

The model is completed with the pricing behavior represented by text equation (1) and reported in Table 3. To begin with the simple specification in Column (a), overall price is overwhelmingly determined by average cost, with a coefficient very nearly unity--confirming the expected pass-through of costs to price--and a t-statistic in excess of 36. It is also clear that the other costs captured in TAXCSR--taxes, payments in lieu of taxes, plus contributions and services--are highly correlated with price, with a t-value greater than 8. But holding costs and other payments constant, public ownership also makes a difference. The coefficient on PUBLIC is negative and statistically significant, and its magnitude implies that power under public ownership is priced 1.9 percent less than from an otherwise comparable IOU. Since this specification holds cost differences constant, the effect would seem to be due to overearning by privately owned and regulated utilities.\[18\]

A more inclusive specification of this model of pricing behavior is reported in column (b), but with little additional insight. Election as opposed to appointment of public utility commissioners makes no difference to price, nor does the extent of competition. The latter is probably because
prices tend to be subject to regulatory or public control even in the presence of a "competitor," and that control appears to blunt, even eliminate, actual price competition. Dummy variables for membership in holding companies or joint action agencies vary in sign, and JAA appears to rise to the level of statistical significance—but with a positive sign. The (negative) price effect of public ownership has risen somewhat, to 2.8 percent, and remains highly significant.

In sum, this aggregate model clearly captures important elements of utility, consumer, and regulator/controller behavior. Striking conclusions emerge confirming the importance of scale and vertical economies, type of generating facilities, capital and tax costs, input prices and the prices of substitute fuels. Critically, public ownership is shown to play significant and independent roles in the cost of electric power as well as in its pricing. In particular, public ownership is responsible for a 2.3 percent cost advantage over IOUs, in addition to which it results in a price that is 1.9 percent less. Together these two factors account for 4.2 percentage points of the nominal 7.4 percent price differential between publicly owned and privately owned electric utilities noted at the outset of this analysis. The long list of other factors is responsible for the remainder.

IV. ESTIMATION RESULTS: MARKET SEGMENTS

The discussion at the outset noted that public ownership may not have a uniform effect on all market segments since it may arise in response to, or at least be responsive to, some particular constituency. Similarly, jurisdictions with elected utility commissioners may have a different relationship of price to cost for residential vs. commercial or industrial
users, as the voting power of residential customers makes itself felt. For such reasons, it is useful to disaggregate the overall market into these three major segments of consumers and to test for differences in pricing behavior among them.

Full generalization would entail estimating cost, demand, and pricing equations for residential, commercial, and industrial users, for a total of nine behavioral equations. For demand and (most importantly) pricing, this disaggregation is straightforward and is reported below. The quadratic and interaction terms in the cost function, however, would lead to an unwieldy proliferation of endogenous variables. Accordingly, we adopt a more modest generalization of the cost function. Specifically, the percent of high-voltage industrial and resale power (PCTHIVO) is included as a hedonic-like control for mix of residential/commercial vs. lower-cost industrial/resale power. Other variables can thus be left unchanged.\(^26\)

As shown in column (e) of Table 2, PCTHIVO is associated with lower total costs. This is no doubt the result of lower line losses from high-voltage power as well as lower service costs to the typically large industrial and resale customers. That said, other coefficients are substantially unchanged. In particular, PUBLIC continues to emerge as a negative and significant force on total utility costs, cet par., with a somewhat smaller point estimate of 1.4 percent.

The demand equation generalization consists of regressions of PRRES on MWHRES, PRCOM on MWHCOM, and PRIND on MWHIND, in each case with appropriate other control variables drawn from the aggregate model. The results are reported in columns (b), (c), and (d) of Table 3. Coefficients appear reasonable throughout, with negative and significant coefficient estimates on
the relevant prices, positive and hugely significant effects from number of customers, positive and generally significant coefficients on natural gas price, and positive effects from the measures of climatic conditions. Income plays its expected role in one of the two regressions in which it is included.

Most important for present purposes is the disaggregation of the equation representing pricing behavior by the regulator or controller. Columns (c), (d), and (e) of Table 4 report the results of pricing equations for residential, commercial, and industrial segments of these utilities' markets, respectively. The results strongly support this view of the pricing process. Price is closely related to average cost throughout, with some evidence of a tighter pass-through relationship (a coefficient closer to unity) for commercial and industrial users than for residential users. This may reflect the greater ability of utilities to justify prices by underlying costs to industrial users. The variable for taxes and other such costs is also significantly related to segment price, but in contrast to average cost, the strongest relationship is now for the residential segment.

As before, the variable PUBLIC captures any difference in pricing practices between publicly owned and privately owned utilities. A striking finding is that public ownership results in a very large and highly significant price reduction of .0153 per kwh, or 19.6 percent, for residential users. Commercial power is priced .0046 per kwh or 6.5 percent less, also statistically significant. By contrast, industrial users not only get no price reduction, but the result in Column (e) implies that their price is actually greater by .0016 per kwh or 3.1 percent. Although this estimate falls somewhat short of conventional levels of statistical significance, a literal interpretation is not at all implausible, as discussed below.
Consistent with the view that governance structures are intended to redistribute rents, residential price also differs in those jurisdictions where public utility commissioners overseeing IOUs are subject to the electoral process. ELECT is negative and significant at about 7 percent in a one-tail test for residential customers, but insignificant for both the commercial and industrial segments. Its estimated coefficient in column (c) implies a .0028 per kwh price reduction, or 4.7 percent, for residential users. While private ownership with elected commissioners does not confer as large a benefit as does public ownership, these may nonetheless be seen as partial substitutes by the politically powerful residential consumers.

The segment-specific results confirm that public ownership is indeed differentially responsive to customer groups, and most responsive to residential customers who rationally favor it for the benefits they extract. Although industrial users of electric power face prices that appear moderately higher relative to underlying costs, it should be remembered that such costs under public ownership have been found to be 2.3 percent lower. On balance, therefore, the price of industrial power is only slightly (0.8 percent) different. Indeed, given the mobility of and supply alternatives available to industrial users, their price could scarcely differ much among utilities.

Table 5 summarizes the estimated cost, pricing, and net effects for the overall market and for the residential, commercial, and industrial segments. As just noted, industrial users are on balance not treated very differently by privately owned vs. publicly owned utilities, whereas residential and to a lesser degree commercial customers are better off under the latter. The process, in sum, appears to be one in which public ownership indeed achieves lower costs, but those benefits are largely extracted by residential users. A
small portion of the cost savings are passed through to commercial users, while industrial customers receive no part of the benefit of public ownership. Although the margins that they face rise, the market price of industrial power is ultimately the same under either ownership arrangement.

V. SUMMARY AND CONCLUSIONS

This paper has sought to determine the effects of public ownership on cost and price performance of electric utilities. Such differences are apparent from cursory inspection of the data and are confirmed by the model that simultaneously examines utility cost behavior, regulator/controller price choices, and consumer demand. Public ownership is found to be associated with significant cost efficiencies relative to comparable privately owned--and regulated--utilities, and is associated with a smaller differential between average cost and price, even after allowing for all other cost influences and advantages to either form of enterprise.

These results have a number of implications for recent theory about and policy towards public ownership. Specifically, the prediction of property rights theory that public ownership has inferior performance attributes is not supported, since both cost and pricing outcomes are in fact superior to those of privately owned utilities. This reflects the relatively poor performance of conventional regulation of such privately owned entities, which is the operative choice for U.S. electric power companies. Present results are more supportive of agency theory which predicts allocative distortions from regulation and productive inefficiencies from both regulated private companies and from public ownership. Productive inefficiencies from regulation have been found greater.
Other theory notes that ownership form is not entirely exogenous:

Public or private ownership may arise in different circumstances, each when it best serves the interests of the most influential group (Hart and Moore (1994), S. Schmidt (1994)). In the present case, that group appears to be local residential customers, by virtue of their numbers and their voting power in municipalities. That they are the primary beneficiaries of public ownership (or alternatively, the popular election of utility commissioners) is clearly confirmed by present analysis. One might therefore suppose that the switch from private to public ownership is led by residential interests who are more likely to prevail in jurisdictions with a small industrial base.

Policy issues, too, are illuminated by this analysis. For example, the movement towards vertical de-integration of electric utilities should be cognizant of the possibility of resulting higher costs. The potential benefits of real retail competition in electricity are probably not really tested in these data, since existing forms of competition are relatively constrained. On the other hand, the weaknesses of regulation are clearly displayed, since it is those weaknesses that ultimately must be responsible for the excess costs and prices by IOUs. Finally, the evidence regarding public ownership suggests that the simple privatization policies being promoted worldwide need not produce the performance benefits often assumed. At least when the privatized entity is to be subject to regulation, this analysis demonstrates that securing superior performance is a considerably more complex task.
## Table 1

### Summary Statistics

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<th>(d)</th>
<th>Segment Model (e)</th>
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<td>--------------</td>
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<tr>
<td></td>
<td>(a)</td>
<td>(b)</td>
<td>(c)</td>
<td>(d)</td>
<td>(e)</td>
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<td>159. (1.24)</td>
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Note: Dependent variable is scaled by 10^-6
* Indicates dummy variables for regions included
### Table 3
#### Equation Demand

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Note: PR\_\_ denotes relevant price for each regression
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Pricing Equation

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DATA APPENDIX

This Appendix defines and describes the variables used in this study and notes their sources.

Quantity, Price, and Costs

Quantity is measured by total megawatthour sales by each utility (MWH), and by its square (MWHSQ). This total is comprised of sales to residential (MWHRES), commercial (MWHCOM), and industrial (MWHIND) users, sales for resale (i.e., to other utilities), plus small amounts devoted to street lighting, etc. Resale mwh is introduced as an exogenous variable in the disaggregate models. All quantity data are from Form 861 (DOE, 1989a).

Price is calculated as average revenue per kwh of total sales (PRAVG). Where appropriate, residential sales price (PRRES), commercial sales price (PRCOM), and industrial sales price (PRIND) are also determined. Revenue data are all taken from Form 861.

Total costs TOTCOST consist of operations and maintenance expenses, depreciation and amortization, interest on long-term debt, and a return on common and preferred stock calculated to remove any overearnings (Hayashi, et al, 1978): That return is the product of outstanding stock and the interest rate on long-term debt, since actual returns based on dividends would reflect actual earnings fluctuations. For a few utilities that reported no such debt, the average interest rate on long-term debt (.0883), was used instead. This approach follows Hayashi et al (1985). Average cost AVGOST is simply TOTCOST/MWH. Sources of data are Forms 1 and 412 (DOE, 1989b and 1989c).

Demand Shifters

The number of customers in the residential, commercial, and industrial segments of the market are represented by CUSTRES, CUSTCOM, and CUSTIND, respectively. Data are from Form 861 (DOE, 1989a).

Disposable income per capita (INCPC) is approximated by the state average disposable income per capita. The latter (and other variables) are weighted where necessary to reflect utilities' multistate operating areas. Per capita income data are from Bureau of the Census (1991).

The price of natural gas--the principle substitute fuel—is calculated for all three customer types and denoted by RESGASPR, COMGASPR, and INDGASPR. Data are from DOE (1990b).

Cooling degree days (COOLDAY) and heating degree days (HEATDAY) in each utility's area are taken from NOAA (1990, 1991).

Competition, Election, and Affiliation

Competition is measured by the percent of each utility's customers that have a rival distribution entity available to it. This characterization does not necessarily imply actual price competition or the ability of customers to switch suppliers, although such cases do exist. Data are from DOE 1989d.
Election of state public utility commissioners is indicated by the ELECT variable. States with elected commissioners are noted in NARUC (1990). Utilities operating in different jurisdictions are assigned a weighted average.

The dummy variable HCREG denotes "registered holding companies," multistate entities with the greatest potential to lower costs. Within-state "exempt" holding companies are designated as HCEx, and joint action agencies--limited cooperative ventures strictly among publicly-owned systems--are identified by the dummy variable JAA. Interfirm affiliations are noted in Financial Statistics (DOE, 1989a).

**Scale and Integration**

Total megawatts of electric power generated is given by GEN and its square GENSQ. The interaction term between power generation and total sales is denoted MWH*GEN. For each generating utility, the percentages of capacity comprised of nuclear, hydro, and "other" are incorporated as CAPNUC, CAPHYD, and CAPOTH, respectively. Data for IOUs are from Form 1 (DOE, 1989b) and for publicly owned utilities, Form 412 (DOE, 1989c).

The size of each utility's transmission network is measured in transmission pole miles and denoted TRANMMI. Data sources are again Forms 1 and 412.

**Input Costs**

Steam fuel cost per steam-generated kwh (PRSTEFU) and nuclear fuel cost per nuclear-generated kwh (PRNUCFU) are calculated by the simple division of each such cost by the amount of such power generated. These are defined only for those utilities that utilize each such input. The price of purchased power (PRPOWER) is calculated in the analogous manner. Fuel cost data and purchased power expenses are from Forms 1 and 412 (DOE, 1989b and 1989c). Generation by type of plant is given in Form 861 (DOE, 1989a).

Since wage data are not available for all utilities, the relevant city or state average manufacturing wage (WAGE) is used instead. Source is Bureau of the Census (1991).

**Capital Cost**

The first definition of capital cost (CCPD) is the familiar weighted average cost of common stock, preferred stock, and long-term debt (Atkinson and Halvorsen, Hayashi et al (1985, 1987), Henderson, and Pescatrice and Trapani.) For publicly-owned utilities, which do not issue stock, CCAP generally reduces to their cost of long-term debt. The cost of common stock is calculated as the fourth-quarter (1989) dividends paid, annualized and divided by year-end stock price. The cost of preferred is total preferred dividends paid divided by the book value of preferred stock. The cost of long-term debt is given by interest on long-term debt divided by long-term debt outstanding. Sources of data are Forms 1 and 412 (DOE, 1989b and 1989c), plus Duff and Phelps (1990).

A somewhat broader and preferred measure of the cost of capital includes
"investment by municipality" plus "constructive surplus/deficit" for publicly owned utilities. "Investment by municipality" includes such things as the cost of utility plant constructed or acquired by the municipality for the utility. "Constructive surplus/deficit" covers a variety of (non-expense) supplies and services exchanged between the utility and the municipality. Since these may be construed as interest-free capital, they would seem to be appropriately included in the capital structure of publicly-owned systems.

Taxes and Other Payments

Tax rates are defined somewhat differently for each type of utility. Taxes paid by IOUs are the sum of federal income taxes, other income taxes, "other" taxes, plus an adjustment as follows: Privately owned utilities can avoid income tax to the extent that current-year credits from accelerated depreciation exceed previously deferred credits come due. This has typically been the case, but for those IOUs for which the reverse is true, their negative net balance increases current year tax liability and is therefore be included.

Publicly owned systems pay certain non-income taxes together with "tax equivalents" or what are sometimes referred to as "payments in lieu of taxes." The composite of these payments by IOUs and publicly-owned systems result in a first approximation of the tax rate per mwh for each utility, denoted as TAXR. Data are from Forms 1 and 412 (DOE, 1989b and 1989c).

This computation is modified to account for the fact that publicly owned utilities often supply services of various kinds to their municipalities effectively in place of taxes or other payments. A more inclusive definition would therefore add publicly owned utilities' "contributions and services" net of any contributions and services provided by their governments to the utilities. This results in TAXCSR as the more comprehensive and preferred measure. Data sources are as before.
FOOTNOTES

1. See also Shleifer and Vishny (1994) and Hart and Moore (1994).

2. Laffont and Tirole offer some observations about relative magnitudes, but within the context of their specific model.


4. See, e.g., Moore (1970), Meyer (1975), and Yunker (1975). Others have interpreted this as evidence of pricing distortion by public managers (DeAllesio; Feltzman; Hollas and Stansell (1988)).


6. The data set was constructed by the American Public Power Association under the author's direction and supervision.

7. Primeaux and Mann (1986) examine the relationships between various electric power prices and utility commission election, but they report no systematic effect.

8. Huettner and Landon (1978) examine the impact of registered holding company membership on various cost factors, but fail to find significant effects.

9. These and all other variables are defined and described in the Data Appendix.

10. An alternative modeling approach would be to assume profit-maximizing behavior and then to estimate utility demand and "quasi-supply." The latter would differ depending upon the degree of pricing discretion exercised by privately owned vs. publicly owned utilities. The doubtful validity of the behavioral assumption and the difficulty of incorporating cost differences between utility types mitigate against this approach. Despite those limitations, exploratory work with such a model has been applied to the present question in Kwoka (1994).

11. Differences among modes of electricity generation suggest some concern about diversity in the present sample. Tests on fossil fuel and nuclear power generation, however, have not clearly indicated the need for separating them in cost function estimation (see Kamerschen and Thompson, 1993). In addition, in the present case the distinction is important only as a control, rather than for the primary purpose of estimating a cost function.

12. A large number of missing values precluded use of analogous data on distribution miles.

14. These data do not contain any utilities that simply generate.

15. The weak performance of the WAGE variable appears to be the result of a mismatch between statewide wage data and the operating experience of individual utilities. Utility-specific wage data produce positive and significant coefficients, but such data are unavailable for a large number of utilities.

16. This is somewhat unexpected, although in a different specification (Kwoka, 1994), hydro power resulted in lower costs and "other" capacity in higher costs.

17. Analogous regressions excluding exempt holding companies and joint action agencies also leave the results unchanged.

18. The alternative of systematic underlearning by publicly owned systems would seem precluded by adjustments already made in the data computation.

19. It is unclear precisely what this may be capturing. One possibility is that joint action agencies may secure price relief for the very reason that they are formed, namely, certain structural disadvantages that the member entities (and it turns out, the agency as well) cannot remedy.

20. Since total sales includes resale mwh, resale is included as an exogenous component of aggregate sales. Previous efforts at disaggregated modelling include Hayashi et al (multiproduct translog cost function) and Hollas et al (1992).
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