

**ELECTRIC POWER DISTRIBUTION:  
ECONOMIES OF SCALE, MERGERS, AND RESTRUCTURING**

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Abstract: Electricity distribution is generally viewed as a natural monopoly and therefore as having the least potential for the kinds of reforms that have swept the electric power sector in many countries. Mergers among distribution companies and efforts at retail competition have nonetheless altered the operation of the distribution stage. This research into US electric utilities uses a much larger and less selective data base than previously available to examine the scale properties of distribution with respect to output, distance, and customer numbers, and for different functions within distribution. It finds significant economies at low output levels, holding system size and customer density constant, but the cost gradient is otherwise modest. It also finds that geographic size and customer numbers are quite important and that economies are significantly stronger for the infrastructure or wires@business than for the marketing function performed by distribution utilities. These results lend credence to efforts at retail competition that separates these functions, but cast doubt on the benefits of mergers between distribution systems.

JEL Classification: L94, L10

## INTRODUCTION

The restructuring of the electric power industry in the U.S. and other countries has focused on the potentially competitive nature of generation, on the central role of transmission, and on price determination. Much less attention has been paid to the economics of the distribution function, perhaps because its natural monopoly properties seem self-evident. But the magnitude and source of such economies are important in designing reforms, determining the need for any residual regulation, and assessing consolidations among distribution companies. Many states and other countries, for example, have embarked on experiments with **A**retail competition,<sup>@</sup> in which multiple marketer-suppliers sell power directly to consumers while the wires over which power is distributed remain a regulated monopoly. This restructuring is intended to isolate the function **B**namely, wires--that is subject to decisive economies of scale, but to allow competition where that is feasible. Interestingly, there is little direct evidence on the key issue of differential scale economies for these two functions that comprise traditional **A**distribution.<sup>@</sup>

With respect to restructuring, reforms have spawned a great deal of consolidation within the distribution sector over the past ten years. Most importantly, the Securities and Exchange Commission in its role as enforcer of the 1935 Public Utilities Holding Company Act has begun to allow mergers, including many between non-contiguous utilities and between gas and electric companies. The effects of that policy change have been dramatic. While there had been little merger activity prior to 1995, more than sixty mergers have been filed since that time. About 40 percent of those have involved non-contiguous utilities, another 20 percent have been gas-electric **A**convergence<sup>@</sup> mergers, and a number have been of enormous size (Joskow, 2000; Moss, 2001). Among the questions that naturally arise is

which, if any, of these mergers are likely to achieve cost efficiencies.

This paper investigates these and several related questions about the distribution stage of the U.S. electric power industry. Two methodological issues and one empirical feature distinguish this study from most others. First, electricity distribution is here represented in a multiproduct framework that represents output in terms not only of megawatt hours but also the number of customers and miles of distribution network. As will be discussed further below, this approach is motivated by the fact that both average customer usage of electricity and customer density on the network affect costs, and a standard method in the literature of controlling for these almost certainly confounds different possible causes of cost differences.

Second, in addition to overall distribution costs, the costs of two subfunctions--wires and supply--are disaggregated and analyzed. Wires denotes the local infrastructure for movement of electricity, while supply comprises the marketing and administrative aspects of the transaction between generators and consumers. As noted above, these two functions have been presumed, rather than shown, to be characterized by different scale properties. The present data permit the bases for that presumption and the resulting policies to be tested.

The third notable feature of this study is the very comprehensive nature of the data base employed. Whereas past studies of the distribution sector have relied upon data with as few as 23 observations and never more than about 200, the present data set consists of 436 of the largest utilities. These account for 74 percent of all electric power sold in the U.S. in 1989. Both investor-owned and publicly owned utilities are included, in each case focusing on the largest and most important utilities. This is the most comprehensive data base that has been used to examine these questions.

The central findings of this study are as follows: (1) Distribution is subject to economies of scale with respect to mwh of output, holding customer usage and density constant. But except at small scales of operation, the cost gradient is quite modest. In addition, there is no indication of cost effects from larger size of service territory. And (2) the scale properties of the wires function are significantly stronger than those for the supply function. Not surprisingly, this is due to the capital intensity of the wires function, in contrast to the largely variable costs of supply. These results provide some justification for some of the restructuring of distribution that has occurred, but they raise questions about the efficiency effects of mergers between electric utilities. These and other implications will be discussed in detail at the end of the paper.

#### **BRIEF REVIEW OF PREVIOUS STUDIES**

Although distribution has received far less attention than other aspects of the electric power sector, a few studies have addressed economies of distribution either directly or incidentally as part of broader inquiries. Early studies by Meyer (1975), Neuberg (1977), and Huettner and Landon (1978) all report evidence of initial scale economies in distribution among US electric utilities. While Meyer found the unit cost curve flattened out at high volume, Neuberg's study suggested persistent economies throughout the observed range of outputs, and Huettner and Landon reported a "somewhat L shaped" curve with unit costs largely flattening out after some point. Neuberg also found that service area did not significantly affect costs. Confidence in these studies is necessarily limited by their typically small samples, their lack of adequate control variables, and the relatively crude empirical specifications employed.

Considerably more sophisticated are studies by Henderson (1985), Roberts (1986), and Nelson and Primeaux (1988). The first two estimate a translog cost function on the generation, transmission, and distribution functions, the third a simpler log version, with all three combining transmission and distribution costs.<sup>1</sup> Both the Roberts study and that by Nelson and Primeaux control for customer numbers and service territory, whereas Henderson does not. Henderson's simpler specification allows him only to conclude that the average cost of transmission-plus-distribution exceeds marginal cost throughout—a characteristic of natural monopoly—and that this difference measures 17.7% at the means of all variables. Roberts's study of IOUs finds that unit costs fall with increased usage per customer but not with customer density or with size of the service area. His estimated cost elasticity with respect to just output is .82. Nelson and Primeaux's study of 23 publicly owned utilities reports persistent economies with respect to just output, but for simultaneous increases in output and customer numbers those economies are exhausted much earlier. They conclude that transmission and distribution may not be natural monopolies.

Recent years have seen several analyses of distribution economies in countries other than the U.S. Hjalmarsson and Veiderpass (1992) on Sweden, Giles and Wyatt (1993) on New Zealand, Salvanes and Tjøtta (1994) on Norway, Burns and Weyman-Jones (1996) on England and Wales, Filippini (1996) on Switzerland, and Yatchew (2000) on Canada all find evidence of scale economies in distribution, although they differ in important details. The New Zealand distribution system and that of Norway, for example, apparently exhaust their economies at relatively modest scale, while others have persistent economies. Moreover, these studies vary in their specification of cost influences. On the one hand, Burns and Weyman-Jones as well as Yatchew hold both usage (or customer numbers) and

density constant, while Filippini omits such factors altogether. As we shall discuss, these variations really test different propositions and yield rather different interpretations of the measured cost effect of output change.

## SPECIFICATION ISSUES

We are interested in representing the relationship between costs and output of the distribution function of electric utilities. A standard cost function for purposes of capturing this relationship would take the form

$$C^D = C^D(Q^D, P^D, X^D) \quad (1)$$

where  $C^D$  denotes total distribution costs,  $Q^D$  is distribution output,  $P^D$  factor prices, and  $X^D$  a vector of exogenous factors affecting distribution costs. Two issues immediately arise with respect to the adequacy of this formulation for present purposes: integrated utilities and multidimensional output.

First with respect to utility integration, we note that there are pure-distribution utilities whose operations are fully captured by equation (1), but many of the largest and most important distributors have been subsidiaries of integrated utilities. To the extent that distribution is part of a production process also involving the generation and transmission of power, the underlying cost function needs to reflect that complexity. Accordingly, we note that the costs of an integrated utility might be written in this general form:

$$C = C(Q^G, Q^T, Q^D, P, X) \quad (2)$$

Here  $Q^G$  and  $Q^T$  denote generation and transmission outputs, respectively, which together with  $Q^D$  are functions of  $P$  and  $X$ --vectors of input prices and other factors affecting costs at all stages of

production. If distribution is independent of generation and transmission,<sup>2</sup> however, then the cost function in equation (2) can be separated thus:

$$C = C^{G,T}(Q^G, Q^T, P, X) + C^D(Q^D, P^D, X^D) \quad (3)$$

$C^{G,T}(\cdot)$  and  $C^D(\cdot)$  are the cost functions for generation plus transmission output and for distribution output, respectively. On the other hand, if distribution and either or both of the other outputs are joint, equation (3) does not hold. The effect on costs may then be captured by including a term that directly measures such jointness:

$$C = C^{G,T}(Q^G, Q^T, P, X) + C^D(Q^D, P^D, X^D) + C^I(Q^G, Q^T, Q^D, P, P^D, X, X^D) \quad (4)$$

Here  $C^I(\cdot)$  is the cost interaction between the upstream generation and transmission outputs and the downstream distribution output  $Q^D$ --that is, the difference in total costs (either positive or negative) resulting from joint production. Suppressing arguments, equation (4) implies the following expression for distribution costs of an integrated utility:

$$C^D(\cdot) = [C(\cdot) - C^{G,T}(\cdot)] - C^I(\cdot) \quad (5)$$

To repeat, the term  $C^I(\cdot)$  will be empirically important only if the downstream stage is not completely separable from upstream output.

Second, while the marketable output of the distribution stage is essentially kwh of electricity, it has often been noted in the literature that  $\Delta$ distribution@ is a function of customer numbers and size of service territory as well. Greater customer numbers increase cet. par. servicing and administrative costs, while larger territories directly affect infrastructure costs. These factors need to be incorporated in some fashion in the cost function in order to properly measure the effect of  $\Delta$ output@ on costs.

There are two possible approaches to this issue, fortunately with the same empirical

implications. For one, customers and service territory can be viewed as  $Q^D$  analogous to kwh of electricity in a multiproduct cost framework. The logic is that, in addition to kwh of electricity, what is being produced includes connections to customers and coverage of territory.<sup>3</sup> An alternative approach is to interpret customer numbers and size of territory as characteristics of the single output variable  $Q^D$  in a hedonic cost function (Berndt, pp. 481-86). In either case, what is required is straightforward: Inclusion of the number of customers and size of service territory in a manner that properly reflects the engineering and operational implications of these factors for distribution costs.

Studies in the literature often have such hedonic-like control variables in their specifications, but in either of two forms. The more straightforward approach is simply to include precisely those variables--customer numbers and size of territory. The alternative captures their effect by including customer usage and customer density, terms more reflective of the underlying mechanism by which costs are affected. Customer usage is average kwh per customer, while density is the number of customers per square mile of service territory or per mile of distribution line. Since kwh of output is included as well, these two approaches are readily shown to be equivalent: Define usage as  $U = Q^D/N$ , where  $N$  is the number of customers, and let density  $D = N/M$ , where  $M$  is miles of distribution line. For expositional convenience only, assume the cost function is linear in outputs and suppress other variables.

We may therefore write the hedonic specification as follows:

$$C = a_0 + a_1 Q^D + a_2 U + a_3 D \quad (6a)$$

This may be compared to the formulation that treats customer numbers and size of territory as additional outputs:

$$C = \beta_0 + \beta_1 Q^D + \beta_2 N + \beta_3 M \quad (6b)$$

Now suppose we wish to measure economies associated with output  $Q^D$ . In equation (6b) the partial effect of  $Q^D$  on  $C$  is  $\beta_1$ , whereas in (6a) the partial effect is  $a_1$ . In each case, however, what is held constant is different. In equation (6b),  $N$  and  $M$  are constant, so that changes in  $Q^D$  necessarily change implied customer usage. The apparent size effect  $a_1$  actually consists of a pure output effect together with the effect of changing per-customer usage. Alternatively, in equation (6a) usage  $U = Q^D/N$  is held constant. But as  $Q^D$  changes,  $U$  can be constant only if  $N$  implicitly changes in the same proportion. Then if  $N$  changes, constancy of density  $D = N/M$  must require mileage  $M$  also to vary proportionally.

Clearly, therefore, constant usage and density involve some further conditions on these variables in equation (6a). Analogous conditions suffice in the case of equation (6b): If  $Q^D$ ,  $N$ , and  $M$  are made to change proportionally, then equation (6b) will yield measured effects of output on total costs that are identical to that in equation (6a).<sup>4</sup> Given the equivalence of the two representations, we can therefore make the choice on the basis of convenience. We opt for equation (6b) since customer numbers and size of service territory are explicit, and hence their effects on costs can be seen more clearly. We emphasize, however, that the empirical results are ultimately invariant between these two specifications.

Finally, we raise two issues of a practical, rather than conceptual, nature. For one, we utilize a quadratic cost function for several reasons. The quadratic handles the many fixed effects terms in the specification more readily than does the principle alternative, the translog cost function. In addition, the quadratic does not make the strong assumption about profit-maximization that underlies the usual estimation procedure for the translog. Also, as Roeller (1986) and others have shown, the translog is by no means always superior in practice, depending upon the specification and region of data space

being investigated. These advantages of the quadratic are offset in part by the fact that it is not homogeneous in factor prices, but on balance it better serves present purposes.

Second, we estimate an average rather than a total cost function. We are, after all, essentially interested in determining whether an appropriately defined average cost curve is U-shaped or not. Moreover, estimation of the relationship in terms of average cost at least partially addresses the problem of heteroskedasticity that otherwise affects a data set with widely varying scales of operation of the observed utilities. A further advantage is that it reduces the problem of multicollinearity that would result from including several size-related explanatory variables in a total cost relationship.<sup>5</sup> And of course, it is not different empirically from the underlying cost total cost function from which it derives.

Based on the above considerations, the distribution cost equation to be estimated can now be written:

$$AC(Q^D) = \beta_0 / Q^D + \beta_1 + \beta_2 Q^D + \beta_3 (Q^D)^2 + \beta_4 N + \beta_5 N^2 + \beta_6 M + \beta_7 M^2 + \beta_8 P + \beta_9 X + e \quad (7)$$

Note that the relevant costs are the incremental costs of distribution, as set out in equation (5) above. The term  $\beta_0$  would be the constant in the equivalent total cost function,<sup>6</sup> and  $e$  is the error term. The quadratic terms on customers  $N$  and miles  $M$  allow for possible nonlinearities in the relationship of those factors to unit costs. Input prices  $P$  and other causal factors  $X$  (including controls for cost interactions with other stages) will be discussed below.

## THE DATA

The construction of the data base used in this study began with all 182 major investor-owned

utilities (IOUs) plus the largest 484 publicly owned systems in the U.S. in 1989.<sup>7</sup> The publicly owned group comprises the vast majority of power sold by the nearly 2000 publicly owned utilities in the U.S., most of which are relatively small. Comprehensive information about each utility's finances and operations was compiled, including cost, quantity, customer, input, and utility characteristics. Despite a major effort, some data were not available for certain utilities, resulting in a data set totaling 543 observations. This data set has been used in previous research and its characteristics and sources are more fully described elsewhere (Kwoka, 1996).

For the purposes of the present study, two additional pieces of information are required: the geographic extent of a utility's operations and the value of its distribution plant. Data on linear miles of distribution network for many utilities were obtained from *Electrical World*. Due to their different cost implications, pole miles and underground miles are separately recorded. For 134 utilities, however, that source did not provide such information. Rather than losing so many observations, a survey instrument was sent out to these utilities. With follow-ups, fully ninety of them ultimately responded and (with only a couple exceptions) could then be included in the data base.

The second additional piece of information concerns the value of distribution plant, which is required to determine capital costs associated with the distribution function. Data for most utilities were available, but again information was either missing or overly aggregated in a number of cases. Extensive efforts were made to resolve these issues, including direct contact with the utilities, but these were not successful in all instances. Non-response and other uncorrectable problems with either distribution miles or plant value information resulted in the present data base of 436 utilities. These utilities account for nearly three-fourths of all electric power sold in the U.S. in 1989--the largest and most

comprehensive data base that has been assembled and used for this purpose.

Of these 436 utilities, 117 are IOUs and 319 are publicly owned. Two hundred and fifty of them generate at least some power while 186 do not. Of these latter pure-distribution utilities, only seven are IOUs. On average these 436 utilities distribute 5.00 million mwh of power to 184,900 customers over a network of 5540 miles. The size distribution is skewed, with 27 percent of the utilities distributing less than 250,000 mwh. The median system distributes 500,000 mwh of output, serves 19,900 customers, and has a network of 500 miles.

A preliminary examination of the data provides insight into several of the major issues to be investigated. We first calculate average total costs, variable costs, and capital-related costs of distribution, each expressed in cents per kwh sold. As shown in Table 1, average distribution costs for the 436 electric utilities in the data base are 1.42 cents per kwh. We emphasize that these are the incremental costs of distribution, that is, net of the acquisition costs of power itself via purchase or internal generation as well as transmission costs.<sup>8</sup> As guidance for the importance of distribution costs, it might be noted that these represent 25.8 percent of average total costs for overall operations of these utilities, that is, power supply, transmission, plus distribution.

Distribution costs are fairly evenly split between what are here termed variable costs and capital-related charges. Variable costs are taken to be operations and maintenance expenses (AO&M@), while capital-related charges are the sum of the cost of capital plus depreciation and amortization (AD&A@). The cost of capital is given by the value of distribution and general plant times a percent capital cost, the latter equal to the weighted average cost of common stock, preferred stock, and long-term debt.<sup>9</sup> While D&A in principle represents a variable cost, it is here combined with the

cost of capital to preserve the careful reporting of O&M in these accounts.

Total costs per kwh can now be disaggregated into the costs arising from the wires function and from supply. Wires costs are the sum of O&M expenses for distribution together with the capital-related charges (that is, cost of capital plus D&A) associated with distribution plant, all of which are reported in the accounts. Supply costs consist of what are termed Aoverhead@expenses, plus capital-related charges associated with Ageneral@plant, that is, capital that does not support generation, transmission, or distribution. Overhead is the sum of expenses from customer accounts, customer service and information, sales, and administrative and general (A&G), all of which are directly reported in utility accounts. All of these are clearly associated with the marketing/supply function. Some ambiguity arises with A&G expenses, which are not specific to supply, or for that matter, not even to distribution. As a result, their magnitude will be a function of the presence or absence of generating facilities and the extent of the utility's other electric operations. This possibility should be borne in mind in examining the data and will be controlled for in the analysis to follow.

Table 1 discloses that the wires function accounts for 59 percent of total distribution costs, the remainder from supply. Not surprisingly, a very large fractionCtwo-thirds, to be specific--of wires costs is associated with the heavy capital investment in the physical network. By contrast, 83 percent of supply costs are variable in nature. The variable (O&M) costs of supply can be further broken down into those deriving from customer accounts, customer service, sales, and administrative and general. The first three of theseCroughly, marketing--account for only 30 percent of the total, the remaining 70% due to A&G. We now turn to an systematic examination of the economic determinants of these costs.

## EMPIRICAL RESULTS

The empirical model to be estimated is based on equation (7) above, which relates unit cost to terms capturing electrical output, customer numbers, and distribution miles. The empirical specification also includes several control variables. Three represent operating characteristics of the utility:

\$Percent of total miles that are underground (UNDER), a factor that is likely to increase costs.

\$Percent of output that is high voltage (HIVO). High voltage power requires less infrastructure (transformers, etc.) and typically is sold in large blocks to industrial customers, furthering lowering costs.

\$Self-generation, represented by a fixed effects term (GEN = 1 for a utility that generates any power) as well as the percent of the utility's requirements that is met by self-generation (SELFG).

These capture possible cost interactions between upstream and downstream utility operation, and are the empirical counterparts to the term  $C^l(\cdot)$  in equation (5). Self generation is likely to result in higher fixed costs (certainly including A&G), whereas its effects on other costs are subject to offsetting influences depending upon how vertical integration affects the organization and operation of generation facilities (Kwoka, ch. 4).

Additional controls are included for factor costs:

\$Labor costs (WAGE), measured by the average manufacturing wage in the state.<sup>10</sup>

\$Capital costs (CAPCOST), which have already been defined.

\$Cost of purchased power (PURPOW), given by total expenditures on purchased power divided by mwh of purchases.

Finally, three fixed effects terms capture the regime in which the utility operates:

\$Public ownership (PUBLIC = 1) may have higher or lower costs, according to various

theories of public enterprise (Kwoka, ch. 2).

\$Combination gas and electric distribution companies are sometimes claimed to realize economies of joint operation.  $GASDIST = 1$  for 143 utilities in the data base.

\$Nine utilities in the data base confront truly competitive distribution companies, where customers can switch suppliers. Those are denoted by  $COMP = 1$  and might be expected to have lower unit cost, *cet. par.*

The results of estimating this equation for average total distribution costs are reported in Table 2, column (a). In this and all subsequent regressions, Huber-White corrected standard errors are reported, since tests indicate some remaining heteroskedasticity.<sup>11</sup> Overall, these results are quite strong, with  $R^2$  of .43, no anomalous coefficient signs, and most coefficients statistically significant.<sup>12</sup> We note in particular that unit costs are strongly related to mwh output in all its forms, to customer numbers in both linear and quadratic form, and to linear distribution miles (at 5 percent significance in a one-tail test) but not to the quadratic term in miles. These results confirm the importance of customers and size of network to costs, underscoring the need to incorporate their influences in measuring scale economies in distribution. We will draw out implications of these findings below, but first we offer some comments on the control variables.

All of the operating characteristics variable are plausibly signed and almost all are statistically significant. A greater proportion of underground miles raises costs, while more high voltage power lowers it. Generating utilities have higher fixed costs, though the coefficient on  $GEN$  is of uncertain significance, and greater self-generation clearly raises unit cost. While this result may appear inconsistent with other studies showing economies from vertical integration, it simply means that vertical

cost savings must arise elsewhere in the transmission function or in generation supply itself rather than in distribution itself. Finally, all three factor cost terms—wages, capital costs, and purchased power—are correctly signed and highly significant.

Among the regime variables, publicly owned distribution systems achieve significantly lower unit cost relative to IOUs. The coefficient implies a 14 percent differential at means of all variables, a result that has been found in many, but not all, previous studies (e.g., Peters, 1993). Competition between distribution utilities also results in significantly lower unit costs, lower by fully 23 percent. Combination gas-electric systems have no discernible effect on costs, belying the proposition that there are economies of scope between the two.<sup>13</sup>

Before quantifying the implications of these results, we also estimate this cost function separately for the two functions that comprise distribution—wires and supply. We recall that approximately three-fifths of costs reside in the wires function, so we might expect overall costs to reflect wires somewhat more closely. We also note that wires costs are far more heavily capital-related than those for the supply function. The estimates reflect these previously noted features of costs. As reported in columns (b) and (c) of Table 2, the effects of output, customer numbers, and distribution miles on wires costs are similar to those found for overall distribution costs, whereas supply costs are driven by a different mix of causes. Since supply consists primarily of marketing and administration, its unit costs are most closely related to customer numbers, not at all to miles, and to output to a lesser extent than in the case of wires. These results suggest some likely differences in the cost and scale properties of wires and supply, a topic to which we shall return.

Among the control variables in the wires and supply equations, most are quite similar. We note

that vertical integration (captured by GEN and SELFG) is more significantly associated with supply costs than with respect to wires, and as before integration results in higher unit costs. It is also noteworthy that the effect of public ownership is much stronger in reducing supply costs than in affecting wires costs. The same phenomenon arises with respect to competition, as duopoly has a greater cost-reducing effect on supply than on wires. Apparently, both regime differences affect service and administration more than they impact the infrastructure side of the distribution business. Finally, we note the continued absence of any effect on unit costs from gas-electric combinations.

The actual values of the estimated coefficients can now be used to determine the magnitude of economies of scale. Our earlier caution about the implied constancy of different control factors now comes into play. To see this, we first take the results reported in column (a) at face value and calculate the U-shaped relationship between unit cost and output defined strictly in terms of mwh. Minimum unit cost apparently occurs at 82.1 million mwh, almost exactly equal to the distribution output of the largest utility in the data base. But this implication that average costs of distribution decline over the range of observed size is an artifact of the way the calculation is performed. By fixing customer numbers, increases in output imply greater customer usage a factor that by itself lowers cost. Hence, the measured economies are the combined effect of increases in both output and usage.<sup>14</sup>

As outlined above, we can resolve this simply by fixing the relationship between customer numbers and output. Thus, we impose the side condition that customer numbers change in constant proportion to output the constant being the mean value thereby ensuring that output per customer remains unchanged. We note further that holding usage constant by varying customer numbers requires changing miles served in order to preserve constant density (customers per mile). By doing so, all three

variables are made to move in unison, reducing the cost equation to one that varies explicitly only with output. This formulation permits us to address such practical questions as the effects on unit costs from the merger of two distribution utilities, where such a merger involves increased customers and miles, but not necessarily any change in average usage or customer density.

We would expect this formulation to show more modest economies of scale than the earlier approach intermingling the cost advantages of greater output and of greater customer usage, and indeed, this proves to be the case. When customer numbers and distribution miles change so as to maintain constancy of usage and density, the average cost curve reaches its minimum value at an output of 36.9 million mwh, less than half the previously estimated value. Based on this cost property, estimated values of unit cost at outputs up to 80 million mwh are calculated and reported in Table 3. Economies of scale are still very much in evidence, especially at low outputs. Average distribution costs fall from 1.61 cents per kwh at 115,000 mwh—the smallest observed utility—down to a low of 1.14 cents at 36.9 million mwh. Notably, costs rise thereafter, up to 1.40 cents at 80 million mwh, about the size of the largest utility in the data base.

Table 3 also reports the cost elasticity—the percentage change in cost for a percent change in output—associated with each of the discrete output values. Clearly, costs decline quite rapidly at small output values, but cost elasticity is less than 10 percent for any output level greater than 250,000. This is not an especially large value and implies that the average cost curve is relatively flat over a considerable range of outputs. This is also clear from other calculations. For example, overall distribution costs are no more than 5 percent in excess of their minimum value of 1.14 cents for all outputs between 16.8 million mwh and 57.2 million mwh—an enormous range of operations with not-

too-dissimilar unit costs. Even a 2 percent cost differential encompasses all outputs between 24.2 million and 49.7 million mwh. These results imply that a failure to fully realize minimum efficient scale does not result in a prohibitive cost penalty, and that utilities of varying size are likely to be able to survive the quite modest cost penalty associated with size.

These effects are apparent in Figure 1, which shows average cost curves for overall distribution and also for wires and supply. The estimated cost function for wires, as reported in Table 2, shows considerably stronger economies of scale than for distribution as a whole. Calculations imply a minimum average wires cost of .884 cents per kwh at a output of 39.9 million mwh, a moderately larger number than for overall distribution. This result is consistent with a further unit cost decreases as the fixed costs of wires operation are averaged over more output and customers. By contrast, economies in the supply function are somewhat more modest, with minimum cost at only 30.7 million mwh.<sup>15</sup> Equally importantly, the average cost curve for supply is much flatter than for wires or overall distribution costs, implying the viability of a wide range of scale without prohibitive cost penalty. Figure 2 is an enlargement of the graph in the small output range where all the cost curves most clearly exhibit economies of scale, but again with differences among them.

These results imply that there are indeed economies of scale in electric power distribution, with a relatively large minimum efficient scale but small cost elasticity over a considerable range of output. Scale effects are exhausted in the supply function at volumes smaller than for wires. There is a wide range of efficient sizes in supply operations and the possibility of competition from multiple providers. By contrast, wires appears to have the stronger scale properties more nearly characteristic of natural monopoly. These considerations, of course, are precisely what underlie current efforts at deintegrating

these two functions, so that the apparently high-scale wires industry will not preclude competition in the potentially competitive supply function.

## SOURCES OF SCALE ECONOMIES

The evidence thus far makes clear that overall distribution, wires, and supply are all subject to economies of scale. Here we seek to determine which of the cost determinants—mwh, customers, miles—are most important to O&M and to capital-related charges, and to make this determination both overall and for wires vs. supply. Our approach is to employ the same model as used in Table 2, since that includes the entire set of factors known to be important overall.<sup>16</sup> Table 4 reports the results on O&M and capital charges for distribution, for wires, and for supply, while Table 5 shows in greater detail the scale properties of the components of overhead costs.

In order to avoid becoming immersed in details of secondary importance, we will note only the broad patterns that characterize these results on the functional components of average distribution costs. In Table 4, both mwh of output and customer numbers play roles similar to those in the overall results reported in Table 2, with the exception of capital-related charges in the supply function. With two minor exceptions, the estimated coefficients on all powers of both mwh and customers are statistically significant. As for the role of miles of distribution network, there is some indication of an effect on overall capital-related costs as well as specifically in the wires function. While this is to be expected, the statistical significance of these effects is marginal. In the case of capital-related charges in supply—a small cost item—none of these variables, and indeed little else of interest, proves to be especially significant.

Among other control variables, it is interesting to note that the cost-reducing effect of public ownership is more systematic with respect to O&M expenses rather than for capital-related charges. The effect of public ownership on O&M, in turn, is greater in the case of supply than wires. The effect of combination gas-electric distribution systems varies in sign and appears to be significant only in lowering operating costs in the supply function. Finally, although the impact of competition achieves statistical significance only for operating costs in the supply function, it has a persistent cost reducing effect in these results.

Earlier discussion had noted that supply consists of four functions--customer accounts, customer service, sales, and A&G-- and that data exist on O&M expenses for these functions. Table 5 reports the results of an inquiry into the sources of scale economies in each of these functions, once again utilizing the same empirical model. As is evident, customer accounts are most affected by both mwh of output and customer numbers, but not with respect to miles. Customer service costs are strongly related to miles and to customer numbers in linear form. Given the nature of customer accounts and service, these associations seem quite reasonable. Less expected is the fact that sales expenses are not particularly related to output or customer numbers. Finally, A&G appears to be significantly and positively driven by all output and customer numbers variables, but again without any association with distribution miles. Since A&G is pure overhead, this latter result seems entirely sensible.

Most other variables are signed as expected and behave predictably. We note that public ownership is systematically associated with lower unit cost. This effect is sizeable and statistically significant in all cases. Combination gas-electric utilities also have a cost-reducing effects on all categories of O&M, although only the estimate for customer accounts is statistically significant.

Competition appears to lower unit costs associated with customer accounts, customer service, and A&G, and to raise costs in the case of sales expense, but the estimated effects are not statistically significant anywhere.<sup>17</sup>

## **IMPLICATIONS FOR MERGERS AND RESTRUCTURING**

After experiencing little change for decades, the U.S. electric power sector has undergone massive transformation. Suddenly over the past ten years mergers have become commonplace. Companies have been deintegrated into generators, transmission entities, and distributors. Distributors are sometimes further dissected into infrastructure and service companies. The present study has focused on the central issue common to these changes, namely, the scale properties of distribution and its components. The data and model employed herein are more comprehensive than most such efforts, and the analysis offers some important insights into the underlying cost structures and their policy implications.

We find that the scale of a distribution utility's operations do affect unit costs, but much depends upon the precise dimension of scale. In particular, there are clear scale effects with respect to mwh of output and to some degree with respect to customer numbers, but little or no effect of size of service territory. Also of great importance are the cost properties by function, with the wires function characterized by larger scale economies than supply of electric power to final consumers.

These results have straightforward implications for the structural changes in the electricity industry. The many mergers in this industry since the mid-1990s have consisted largely of combinations of service territories. While such mergers necessarily increase total mwh of output, customer numbers,

and service territory, the effects on unit costs are largely those attributable to increased territory, holding essentially constant both customer usage and customer density. Based on the present evidence, there is little or no effect from increasing the scale of service territory by itself. It is an increase in usage or an increase in density, and not the mere expansion of service territory, that causes unit costs to fall. As a consequence, the purpose and the effects of these mergers must be found elsewhere.

In addition, while there are measurable scale effects with respect to both output and customer numbers, for the most part the relationship is relatively flat. There is evidence of a significant fall in costs at quite small outputs, and evidence of a rise at the largest volumes, but unit costs do not otherwise change much across a rather wide range of outputs. This implies that utilities that vary considerably in size may nonetheless remain fairly cost-competitive and viable in this industry.

Disaggregation of costs into the wires and supply functions has further implications for industry restructuring. The evidence suggests that wires remains characterized by high scale, consistent with most proposals that it continue as a regulated monopoly. By contrast, supply would appear potentially competitive in that scale effects, while not absent, are much smaller except at very small sizes. These results provide support for current policy initiatives that on the one hand encourage competition in the business of supply, but still regulate the wires function as a natural monopoly.

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**TABLE 1**  
**SUMMARY STATISTICS**  
**(cents per kwh)**

	<u>TOTAL</u>	<u>O&amp;M</u>	<u>CAPITAL-RELATED</u>
DISTRIBUTION	1.415	0.759	0.657
WIRES	0.835	0.280	0.556
SUPPLY	0.580	0.479	0.101
CUSTOMER ACCOUNTS		0.105	
CUSTOMER SERVICE		0.022	
SALES		0.006	
A&G		0.346	

**TABLE 4**  
**Determinants of Average Cost**

	( a ) <u>DISTRIBUTION</u>	( b ) <u>WIRES</u>	( c ) <u>SUPPLY</u>
RMWH(10 <sup>6</sup> )	0.394 (2.18)	0.300 (2.52)	0.093 (0.93)
MWH(10 <sup>-6</sup> )	-0.798 (5.11)	-0.536 (4.20)	-0.263 (3.92)
MWHSQ(10 <sup>-12</sup> )	0.0051 (3.28)	0.0032 (2.96)	0.0019 (2.62)
CUST(10 <sup>-6</sup> )	14.8 (4.33)	10.2 (4.04)	4.59 (2.78)
CUSTSQ(10 <sup>-12</sup> )	-2.22 (2.96)	-1.49 (2.81)	-0.723 (2.11)
MILES(10 <sup>-6</sup> )	165 (1.69)	125 (1.52)	39.7 (0.95)
MILESQ(10 <sup>-12</sup> )	-0.072 (0.97)	-0.055 (0.90)	0.017 (0.49)
UNDER(%)	5.98 (2.65)	2.62 (1.69)	3.36 (2.72)
HIVO(%)	-9.71 (7.28)	-5.82 (7.49)	-3.89 (4.64)
SELFG(%)	3.87 (3.10)	1.68 (1.56)	2.19 (3.77)
GEN	1.08 (1.38)	0.216 (0.46)	0.868 (1.82)
WAGE	0.791 (3.46)	0.372 (2.65)	0.419 (3.01)
CAPCOST	49.9 (4.47)	47.7 (6.58)	2.22 (0.38)
PURPOW	0.126 (5.02)	0.053 (2.77)	0.074 (6.48)
PUBLIC	-1.98 (2.17)	-0.330 (0.51)	-1.65 (3.45)
GASDIST	-0.061 (0.09)	-0.032 (0.07)	-0.029 (0.07)
COMP	-3.14 (2.12)	-1.37 (1.08)	-1.77 (3.09)
CONSTANT	-0.153 (0.05)	0.306 (0.15)	-0.459 (0.29)
R <sup>2</sup>	0.43	0.35	0.32
F	18.5	13.5	11.5

**TABLE 3**  
**CALCULATED UNIT COSTS AND ELASTICITIES FOR DISTRIBUTION**

<u>MWH (millions)</u>	<u>AC (\$)</u>	<u>Cost Elasticity</u>
0.02	29.4	-0.55
0.115	16.1	-0.17
0.25	14.6	-0.09
0.50	13.9	-0.05
1.0	15.4	-0.03
5.0	12.9	-0.04
10.0	12.5	-0.06
20.0	11.8	-0.08
30.0	11.5	-0.05
36.9	11.4	0.0
40.0	11.5	0.03
60.0	12.2	0.32
80.0	14.0	0.69

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**DETERMINANTS OF AVERAGE COST BY FUNCTION**

	( a )	( b )	( c )
	DISTRIBUTION <u>O&amp;M</u>	DISTRIBUTION <u>CAPITAL</u>	<u>WIRES O&amp;M</u>
RMWH(10 <sup>6</sup> )	0.180 (2.36)	0.215 (1.44)	0.093 (2.22)
MWH(10 <sup>6</sup> )	-0.352 (5.19)	-0.447 (3.72)	-0.103 (3.54)
MWHSQ(10 <sup>-12</sup> )	0.0022 (3.12)	0.0029 (2.81)	0.0006 (2.17)
CUST(10 <sup>6</sup> )	7.58 (3.94)	7.25 (3.07)	2.58 (3.04)
CUSTSQ(10 <sup>-12</sup> )	-1.18 (3.02)	-1.03 (2.10)	-0.443 (2.86)
MILES(10 <sup>6</sup> )	9.25 (0.25)	155 (1.92)	-6.18 (0.37)
MILESQ(10 <sup>-12</sup> )	214 (0.74)	-933 (1.56)	174 (1.20)
UNDER(%)	2.54 (2.37)	3.45 (2.03)	-0.287 (0.56)
HIVO(%)	-5.55 (7.81)	-4.16 (4.26)	-2.52 (6.70)
SELFG(%)	2.20 (3.80)	1.67 (1.83)	0.178 (0.58)
GEN	1.37 (3.12)	-0.282 (0.51)	0.254 (1.23)
WAGE	0.527 (4.56)	0.264 (1.47)	0.155 (2.30)
CAPCOST	-5.81 (1.00)	55.7 (7.35)	-0.155 (0.06)
PURPOW	0.095 (7.05)	0.031 (1.83)	0.023 (3.53)
PUBLIC	-2.37 (5.24)	0.393 (0.61)	-0.337 (1.73)
GASDIST	-0.507 (1.71)	0.446 (0.74)	-0.010 (0.06)
COMP	-1.16 (1.67)	-1.97 (1.63)	0.042 (0.10)
CONSTANT	0.879 (0.56)	-1.03 (0.49)	1.21 (1.35)
R <sup>2</sup>	0.48	0.30	0.24
F	23.0	10.3	7.9



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**DETERMINANTS OF AVERAGE COST BY FUNCTION**

	( d ) WIRES <u>CAPITAL</u>	( e ) <u>SUPPLY O&amp;M</u>	( f ) SUPPLY <u>CAPITAL</u>
RMWH(10 <sup>6</sup> )	0.207 (2.09)	0.086 (1.39)	0.007 (0.09)
MWH(10 <sup>-6</sup> )	-0.043 (3.77)	-0.249 (4.58)	-0.014 (0.49)
MWHSQ(10 <sup>-12</sup> )	0.0027 (2.88)	0.0016 (2.92)	0.0003 (0.33)
CUST(10 <sup>-6</sup> )	7.66 (3.41)	5.00 (3.47)	-0.415 (0.49)
CUSTSQ(10 <sup>-12</sup> )	-1.05 (2.22)	-0.739 (2.44)	0.0016 (0.89)
MILES(10 <sup>-6</sup> )	131 (1.67)	15.4 (0.50)	24.2 (1.19)
MILESQ(10 <sup>-12</sup> )	-719 (1.26)	40.5 (0.16)	-215 (1.23)
UNDER(%)	2.91 (2.19)	2.82 (3.23)	0.540 (0.66)
HIVO(%)	-3.30 (5.21)	-3.03 (5.44)	-0.860 (1.52)
SELFG(%)	1.50 (1.73)	2.02 (4.11)	0.175 (0.74)
GEN	0.037 (0.10)	1.11 (3.19)	0.245 (0.84)
WAGE	0.217 (1.93)	0.372 (3.99)	0.046 (0.48)
CAPCOST	47.9 (8.33)	-5.66 (1.29)	7.87 (2.11)
PURPOW	0.029 (1.82)	0.072 (7.03)	0.0018 (0.34)
PUBLIC	0.007 (0.01)	-2.03 (5.79)	0.386 (1.42)
GASDIST	-0.022 (0.06)	-0.497 (2.13)	0.468 (1.43)
COMP	-1.41 (1.15)	-1.21 (2.37)	-0.562 (3.49)
CONSTANT	-0.906 (0.54)	-0.333 (0.26)	-0.126 (0.14)
R <sup>2</sup>	0.35	0.47	0.05
F	13.2	21.5	1.2

**TABLE 5**  
**DETERMINANTS OF AVERAGE COST OF O AND M**

	( a ) CUSTOMER <u>ACCOUNTS</u>	( b ) CUSTOMER <u>SERVICE</u>	( c ) <u>SALES</u>	( d ) <u>A&amp;G</u>
RMWH(10 <sup>6</sup> )	-0.014 (0.69)	-0.0040 (0.35)	0.0099 (1.55)	0.095 (1.74)
MWH(10 <sup>6</sup> )	0.0084 (7.23)	-0.0019 (1.80)	0.0070 (0.16)	-0.147 (3.11)
MWHSQ(10 <sup>-12</sup> )	0.0005 (5.19)	0.00003 (0.38)	-0.00003 (0.78)	0.0011 (2.14)
CUST(10 <sup>6</sup> )	1.88 (5.60)	0.464 (1.96)	-0.056 (0.70)	2.71 (2.19)
CUSTSQ(10 <sup>-12</sup> )	-0.306 (4.93)	-0.037 (0.73)	0.012 (0.77)	-0.407 (1.60)
MILES(10 <sup>6</sup> )	5.49 (0.70)	13.1 (1.46)	3.89 (1.24)	-7.01 (0.27)
MILESQ(10 <sup>-12</sup> )	17.4 (0.28)	-126 (1.80)	-30.4 (1.31)	180 (0.81)
UNDER(%)	0.602 (2.87)	0.060 (0.48)	0.038 (0.91)	2.12 (2.72)
HIVO(%)	-0.428 (2.64)	-0.270 (2.74)	-0.037 (0.86)	-2.29 (4.83)
SELFG(%)	0.333 (2.73)	-0.125 (1.60)	-0.012 (0.50)	1.80 (3.98)
GEN	-0.011 (0.11)	0.108 (1.72)	-0.015 (0.08)	1.02 (3.22)
WAGE	0.040 (1.49)	-0.018 (1.40)	-0.006 (1.01)	0.357 (4.36)
CAPCOST	-1.59 (1.39)	-0.426 (0.77)	0.189 (0.52)	-3.84 (1.05)
PURPOW	0.016 (5.27)	0.0039 (2.39)	0.0005 (0.83)	0.059 (6.88)
PUBLIC	-0.559 (5.19)	-0.169 (3.03)	-0.046 (2.08)	-1.26 (4.22)
GASDIST	-0.149 (2.09)	-0.038 (0.91)	-0.024 (1.60)	-0.285 (1.37)
COMP	-0.265 (1.00)	-0.074 (0.52)	0.107 (1.18)	-0.975 (1.57)
CONSTANT	0.638 (1.79)	0.775 (3.96)	0.111 (1.41)	-1.86 (1.70)
R <sup>2</sup>	0.32	0.19	0.05	0.39



## ENDNOTES

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<sup>1</sup>Transmission and distribution are commonly combined, both to conserve degrees of freedom and because of their rough similarity. The present study will separate the two.

<sup>2</sup> It has often been argued that distribution is likely to be separable from generation and transmission, whereas generation and transmission are related. The reason for the latter is that size and siting decisions for generation capacity directly affect transmission costs. Local distribution, by contrast, is structured for end users and therefore would appear independent of upstream operations. See, for example, Burns and Weyman-Jones, pp. 42-43. Studies of economies of joint operation come to mixed conclusions. See Kaserman and Mayo (1991), Gilsdorf (1994), and Hayashi et al (1997).

<sup>3</sup> Indeed, since there is often a customer charge for local distribution, there is a factual basis for this view.

<sup>4</sup> This is the equivalent of taking the total derivative and imposing proportionality as a side condition on the partials with respect to the two variables.

<sup>5</sup> We later test for and correct remaining heteroskedasticity. While both heteroskedasticity and multicollinearity could be addressed in any form of this equation, we take advantage of this specification opportunity to reduce its effects.

<sup>6</sup> The relevant part of the underlying total cost function can be written as follows:

$$C(Q^D) = \beta_0 + \beta_1 Q^D + \beta_2 (Q^D)^2 + \beta_3 (Q^D)^3$$

Dividing by  $Q^D$  gives text equation (7).

<sup>7</sup> Although there have been a number of important structural changes in the industry since 1989, most of those have occurred in the generation and transmission stages. The economics of the distribution stage itself are driven by much the same forces as before.

<sup>8</sup> Put in terms previously employed, distribution costs are  $[C(.) - C^{G,T}(.)]$ . See equation (5).

<sup>9</sup> The cost of common stock is measured by dividend yield, while the cost of preferred is preferred dividends divided by outstanding preferred stock. The cost of long-term debt is percent interest paid.

<sup>10</sup> While a utility-specific labor cost would be preferable, such data are missing for too large a number of utilities in this data base. Use of this manufacturing wage proxy has precedent in, e.g., Nelson and Primeaux .

<sup>11</sup> The Cook-Weisberg test on the residuals of the OLS version of this regression results in a chi-square of 25.76, indicating remaining heteroskedasticity.

<sup>12</sup> Both  $R^2$  and especially  $R^2$  are calculated differently and require careful interpretation in the case of heteroskedasticity-corrected estimates, since the standard errors have changed.  $R^2$  continues to be a valid measure of overall goodness of fit, however, and is therefore the superior measure.

13 Similar negative results have been reported by Mayo (1984) and Sing (1987).

14 There is starkest possible proof of this distortion: While unit cost is minimized at 82.1 million mwh, the actual value of unit cost is *negative* at that point. Greater mwh of output are being used by a constant number of customers, and the increased usage **B**really, beyond plausible values--drives unit costs into infeasible regions.

15 These estimates overstate economies in supply to the extent that all "general plant" is attributed to supply. Previous discussion noted its multiple functions, which cannot be disentangled in these cost data directly, but we do include controls for those in the empirical estimation.

16 Use of the same model facilitates comparison across cost categories and aids in understanding what components are most responsible for the effects found in the overall cost regression.

17 This possibility that competition might raise unit costs rather than lowering them has often been found in advertising and marketing studies (See, e.g., Scherer, 1990, p. 598)

FIGURE 1

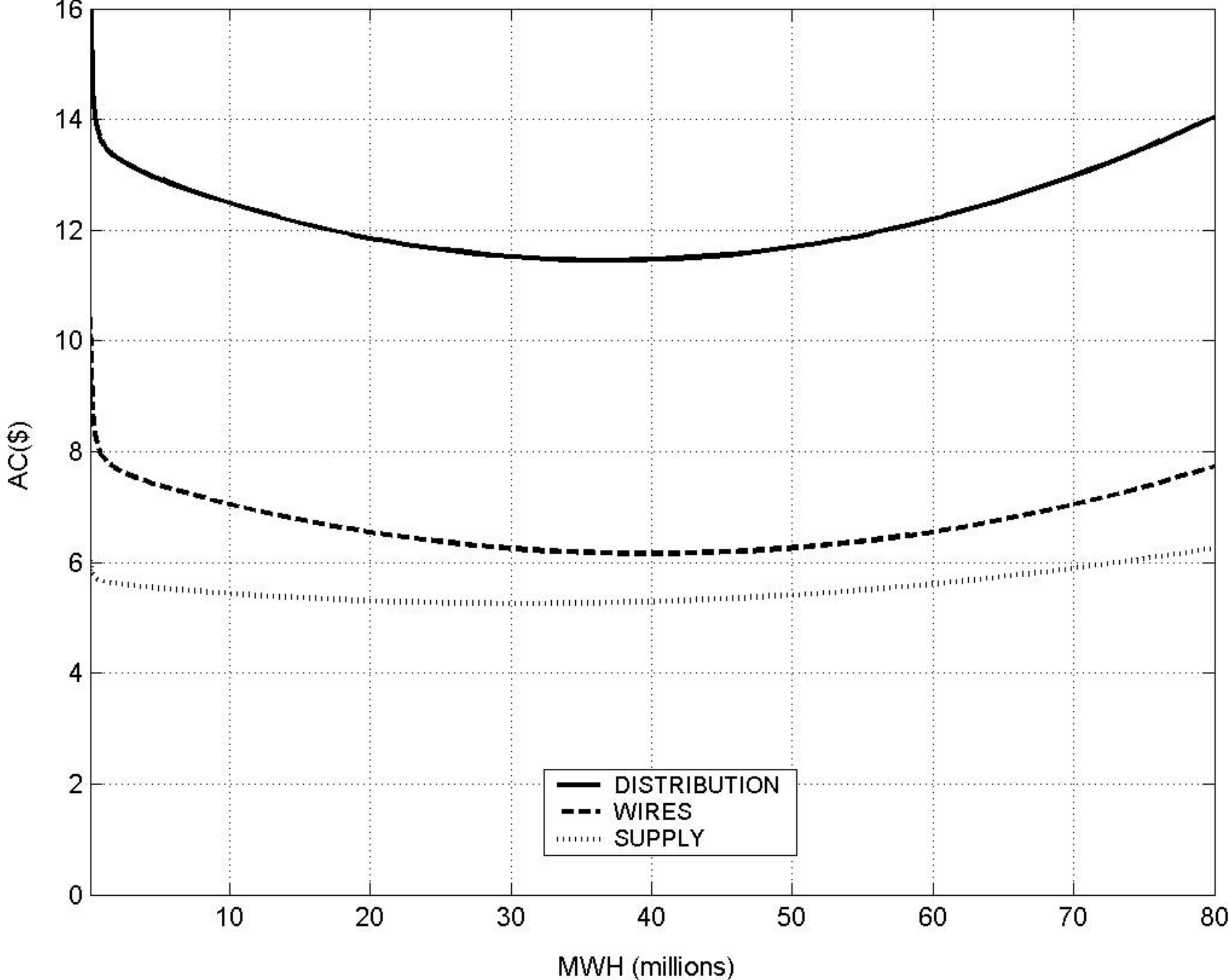


FIGURE 2

