Repeated Regulatory Failures,

Electric Utilities in the UK, 1882-1934

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rough draft

Introduction

Since their establishment, some have questioned why British electric utilities had such a poor performance record in the first half of the twentieth century. The answer is often said to lie in a failure of private enterprise that was peculiar to Britain, or alternatively, in a failure of municipal enterprise. There is another alternative that has been little explored; namely, the unusual market structure, which contrasted sharply with the large, regulated utilities we now see in most of the world—all utilities were small, essentially unregulated monopolies.

The two main features of the pre-War regulatory environment in Britain are a lack of binding price regulation and the establishment of many, small, franchised monopolies going back as far as 1882. The decision to approve an application by a prospective utility was made by the local council. Parliament thought this best since the local council would have to approve any laying of cable under city streets and so forth. A corollary to the second feature is that many municipalities retained the franchise themselves, and those that did not were permitted, under the 1888 Electricity Supply Act, to purchase any private supplier under their jurisdiction after forty-two years of operation.

What emerged from this was a patchwork of many small integrated utilities, engaged in both generation and distribution, with a variety of currents (AC & DC), frequencies of AC, voltages, and cable systems. Some of these problems soon became rather minor—transforming voltages became routine—but others remained major obstacles—converting frequencies and current was done with a motor generator, which was simply an electric motor powering a generator producing the desired frequency or current. While this small scale was initially satisfactory, the rapid technological advances in generation and transmission soon made the small scale inefficient. Further development of alternating current allowed for high-voltage transmission of electricity over longer distances with lower losses than had been possible with direct current. Both of these advances made the small size of most utilities an obstacle to cost efficiency, and one would expect them to merge. If not mergers, then one would expect some firms to close their generators and purchase in bulk from neighboring suppliers.

The Electric Lighting Act of 1882

The electric utility industry in the United Kingdom was largely established by passage of the Electric Lighting Act of 1882.[1] Parliamentary hearings held before passage of the Act took place in an environment of great uncertainty—it was hard to determine costs without knowing what demand might be. The precedent of the gas utilities figured prominently in discussions and in the Act itself. In fact, the Act simply included, by reference alone, portions of the Gasworks Clauses Acts of 1847 and 1871, with "electricity" and "electric line" to be substituted for "gas" and "pipe" respectively. The Act established both the structure of the industry, which lasted until nationalization of the industry sixty years later, and a loose but inflexible regulatory framework that proved to be somewhat less durable. The structure adopted was that of a patchwork of monopolies serving relatively small areas; the regulation established was a twofold system of maximum prices and the granting of a compulsory right of purchase to local councils after a twenty-one year period. Over the years, these three features would each develop into problems at various times.[2]

Promoters wishing to establish an electric utility required Parliamentary approval, and a requirement for Parliamentary approval was approval by the local council; this

[1] Non-statutory suppliers first appeared in 1881 and continued to exist at least through the 1920s. These firms suffered from the disadvantage that they could not lay their lines on public lands and other restrictions, consequently they tended to be quite small, e.g., serving a resort and its neighbors, the boardwalk in Brighton, and some small villages.

[2] Sources for Acts of Parliament are British Parliamentary Papers for the respective years, both the bills and the hearings that preceded them, which are typically lengthy and informative.

tended to result in applications to serve an area that would be entirely under the authority of a single council.

The regulatory framework was loose in that the utilities were given fairly wide latitude in their actions. While local councils had control over activities such as the laying of electric lines under the streets or on poles, the only other restrictions were a maximum price and the compulsory right of the local council to purchase the utility twenty-one years after Parliamentary approval.[3] Under the provisions of the 1882 Act, if the utility and council could not agree on a purchase price, it was to be set by arbitration at the fair market value of the materials. The regulations were rigid in that, once established, it was quite difficult to change them: the maximum price was established in the initial Act or Order, and changes to the maximum price could be made only by subsequent Acts or Orders. The terms of valuation could not be changed at all, and this made the compulsory purchase clause quite onerous to prospective investors.

The success of the 1882 Act must be measured by the scarcity of firms entering the market: although numerous orders had been granted, by 1886 only one authorized utility had commenced provision of electric current.

The Electric Lighting Act of 1888

In 1886 Parliament re-examined the industry, showing concern for the attraction of capital while maintaining both prices and rates of return at reasonable levels. The compulsory purchase clause received the most attention, with both the terms of valuation and the duration before the option to purchase coming under scrutiny.

Given the uncertainty surrounding such a new technology and the competition offered by gas lighting, the duration was considered to be too short a period of time to obtain a return on the initial investment.

[3] The compulsory right could be exercised only during a six-month window that began on the twenty-first anniversary of the initial Act or Order. Another six-month window began on the twenty-eighth anniversary and every seven years thereafter.

While it makes little sense that a business enterprise should be purchased for a price determined solely by the value of its materials, there was a surprising amount of resistance to changing these terms. Those who considerded that the terms of purchase were a deterrent to investors made two proposals: that the utility be valued as a going concern measured by past profits, which some considered to be unfair to growing firms; and that the utility be valued as a going concern including prospective profits, which was what a willing purchaser would pay. Speaking against these proposals, Henry G. Calcroft, the permanent secretary of the Board of Trade, offered that purchase as a going concern would be "likely to cause a very large unnecesary sum of money to be expended by the local authority when they purchase the undertaking."

The Electricity Supply Act of 1888 reflected the parliamentary hearings of 1886. This act made the simple repairs to the compulsory purchase clause, but did nothing more, apart from giving the Board of Trade the power to override the unwillingness of a local authority to consent to the establishment of a utility in its jurisdiction. The terms of purchase were revised to include prospective profits when valuing the firm, and the duration before compulsory purchase was doubled to forty-two years. The Board was also given the power to change the terms of purchase through a Provisional Order.

The 1888 Act was the first attempt by Parliament to reform the electric utility industry. The symptom treated was the almost complete lack of entry, which was diagnosed as being largely due to just one of the "three problems," the compulsory purchase clause. Clearly, the 1888 Act succeeded in addressing this one problem: hundreds of utilities commenced the supply of electricity throughout Britain and Ireland under its revisions to the compulsory purchase clause. The 1888 Act, limited success that it was, is the acme of electric utility regulation in the UK prior to nationalization.

The Electric Lighting Acts of 1899 and 1909

After the 1888 Act, two of the three problems remained: patchwork market structure and pricing. Although no major reforms were contemplated until the end of World War I, Parliament passed some minor acts during the intervening thirty years. Two of these, the Electric Lighting (Clauses) Act of 1899 and the Electric Lighting Act of 1909, actually addressed the second of these problems, pricing, by taking the step of introducing a means of revising maximum prices. Taken at face value, a repair of one of the three problems would seem to be a major reform, but in fact, there is very little record of these acts being used to obtain reductions in maximum prices.

In fact, throughout this period, there seems to have been little interest in actually using maximum price as a means of regulation. We can gauge the interest of the Board of Trade and Parliament in maximum prices by examining the maximum price stated in Parliamentary orders granted for the establishment of new utilities. In Table 0 we see that maximum price has fallen by less than 10 percent over the years and that the mode has stayed at eight for all the years included in the table.

Taking the maximum price of eight pence, we can get a good idea of how binding it was in 1919 by comparing it to the average revenue per kilowatthour. Of all 296 utilities that report average revenue, only two have average revenue exceeding eight pence, and both of these have a maximum price equalling eight pence. Median average revenue is only 0.87d. This apparently complete lack of interest in using what we now consider to be one of the basic tools of utility regulation is surprising, particularly so when considering the complete change of attitude toward the industry shown in 1919.

The Electricity (Supply) Act of 1919

By 1919, a number of complicated issues had emerged that can be traced back to the two remaining problems of the 1882 Act: the patchwork market structure and lack of effective price regulation. While the issues involved were decidedly more complex than those faced previously, and one would not be surprised if they were not addressed in an entirely successful manner, one would hope that the problems would at least be successfully identified.

The report of the Williamson Committee served as a blueprint for the 1919 Act,[4] and its tone is quite illustrative of both the change in attitude toward the industry and the inadequate comprehension of the problems. In discussing the great need for repairs and expansion at the close of World War I and the need for the proper sort of preparations to carry these out, the committee describes the current condition and trends of the industry with language that is not so much descriptive of a problem as it is a condemnation of those who might dare to oppose the Committee's report: "the evil will grow until it is beyond remedy." Throughout the report, it is admitted that the findings and recommendations of the committee will be opposed by many, but they are "in the national interest" and should be supported.

The recommendations of the committee marked a complete break with past Parliamentary efforts to reform the industry, and was, in fact, the first attempt to nationalize electric utilities. It proposed establishment of the Electricity Commission and placed under it District Electricity Boards, the latter being charged with rationalizing production in their respective districts, and granted them a great deal of authority, including the power of compulsory purchase of any utilities or plant in their district. In the end, the House of Lords would not pass the bill in this form, and renamed the District Electricity Boards as Joint Electricity Authorities while stripping them of most of their authority, including the compulsory purchase powers. Significantly, in 1920 and 1921 Parliament tried to pass bills that would have restored the language removed by the

[4] This committee was more formally known as the Electric Power Supply Committee and was chaired by Sir Archibald Williamson. The committee was appointed by the Board of Trade and reported to Parliament; it was charged "to consider and report what steps should be taken, whether by legislation or otherwise, to insure that there shall be an adequate and economical supply of Electric Power for all classes of consumers in the United Kingdom, particularly industries which depend upon a cheap supply of power for their development."

House of Lords, and in 1926 Parliament did pass an act designed to achieve the aims of the 1919 Act with somewhat less government intervention.

Neither the report of the Committee nor the Act itself directly addressed the problems facing the industry; a new organization was simply created and directed to address these problems. The Committee's chief recommendations were largely twofold: the establishment of the Electricity Commission and District Electricity Boards as government organizations and the elimination of the patchwork market structure in generation (but not distribution). Although brief mention was made of price regulation, it was left to the Commissioners to determine what or if any action would be taken.

It is interesting to examine the industry quantitatively and get a picture of just what the new Electricity Commission faced. In so doing, we will be in a better position to evaluate both the suppositions made in establishing the Commission and subsequent actions of Parliament and the Commission.

Chapter 2

The Failure of 1919

As recounted, there are numerous candidates for the relative inefficiency of the British electric utility industry. Either municipal or private ownership could be at fault, or the high costs could be due to another factor—the small firm size, the variety of currents, or some similar factor related to market structure. Here we will attempt to determine what are the reasons for high costs in the British industry by examining some reasons for differences in costs within the British industry.

One possibility is that munis were not as cost efficient as IOUs, and this was the reason for the apparently industry-wide low efficiency. Investor-owned utilities presumably would agree to a merger or buyout if a price could be agreed upon. Munis, on the other hand, have nothing corresponding to the profit maximizing behavior of the IOUs to induce a sale. It was not unusual for local councils to fear they would lose control of their electricity supply and be at the mercy of some distant, large municipality for their electricity supply. Some munis were used as cash cows by their local councils; others had objectives of subsidizing residential customers at the expense of small industry, or of subsidizing electricity with tax revenues. The local councils governing these munis might not see a merger to be in their interests at all, or could legitimately argue that voters (or consumers) would be worse off after a merger or sale.

A similar argument is that of entrepreneurial failure. At the time, needed reforms to the industry were widely discussed—e.g., mergers to attain efficient scale and reduce the large number of firms—but IOUs failed to move in this direction due to what was called entrepreneurial failure. Further, it was noted that most of the largest firms were munis, thus buttressing the argument that IOUs were at fault for not taking advantage of economies of scale.

The Issues

It is fairly straightforward to test the influence of ownership. A variety of econometric studies have examined this question at various times and places, and all estimate some sort of reduced form cost function with a binary dummy for ownership type, and I adopt this general approach here. This method is also convenient for testing other possible sources of cost inefficiency, including scale economies and type of current.

As reviewed in the previous chapter, there are other possible sources of cost inefficiencies, including the compulsory purchase clause, maximum price regulation, and further aspects of the patchwork system—firm size, current, voltage, frequency, and wiring. These possibilities can also be tested with the above-mentioned reduced form cost function by adding independent variables to the estimated equation. Moreover, every variable can be interacted with the ownership dummy, which provides a powerful method for separating ownership from scale or other effects. This doubles the number of independent variables, and makes it more difficult to examine the results. What matters is not simply whether or not a variable is statistically significant, but the magnitude of its effect relative to that of other variables, or taken in combination with them.

For a variety of reasons, the compulsory purchase clause is difficult to test with this method. Exceptions to this clause were incorporated into the utility's Parliamentary order and could include either or both the duration before opportunity to purchase and the calculation of the purchase price. Calculation of the purchase price can only be tested by including one or more dummy variables for observations with exceptional terms; similarly, duration could be tested by this method, or by including the duration itself as a variable. One difficulty with these tests is that munis only rarely had such exceptions—when one jurisdiction was supplied by a utility operated by a neighboring jurisdiction—and approximately 70 percent of the firms are munis. With only seventy-seven IOUs, it may be difficult to measure any effects of exceptional terms. A further difficulty is that the default duration was forty-two years, and since only seven utilities in this dataset received their order prior to the 1888 Act, there are very few IOUs that face imminent purchase by the municipal government in 1919, hindering the measurement of the impact such purchase might have.

The influence of maximum price regulation is easy to test by simply including as a variable the maximum price, or the weighted average if the utility has more than one order.

Annual sales is the most useful way of measuring firm size; it can be included as an independent variable in the reduced form cost function. The usefulness of this can be seen in the distribution of annual sales by ownership in Table 1; both IOUs and munis have the same mode, but the distribution of IOUs is skewed in the direction of smaller firms, while that of munis is skewed in the direction of larger firms. This difference in annual sales is correlated with other disparities, as seen in Table 2. In addition to having a larger median size, munis have lower average operating costs; this inverse relationship reflects the existence of economies of scale, but one could also hypothesize that the difference is due at least in part to ownership rather than scale economies. Unsurprisingly, munis serve markets having a median population more than twice that of IOUs and have median sales per capita nearly twice that of IOUs; the latter primarily indicating that munis tend to have more industrial customers. Munis also have a higher capacity, peak load, and load factor; the latter is to be expected since they are larger and have more industrial customers and thus a more diverse load.[5] Maximum voltages are also much higher for munis, which simply reflects the fact that more munis have AC, which can be transmitted at higher voltages.

Munis and IOUs share the same median maximum price and roughly the same dates for their parliamentary orders and commencment of supply. Nearly the same proportions of each have interconnections with other firms and have only alternating current. It is noteworthy, however, that IOUs are much more likely to have DC current and much less

[5] Annual sales and load factor have a correlation of 0.32.

likely to have mixed systems. There is also considerable regional heterogeneity in the distribution of munis and IOUs, with both found in more or less similar numbers in the south of England, as exemplified by the figures for the Greater London Electricity Area, but munis comprise about 90 percent of the total in Scotland and the north of England. This makes it difficult to separate any regional cost variations from ownership effects. Finally, it is worth noting that average revenues exceed average costs by about 40 percent for both IOUs and munis, perhaps laying to rest the notion that munis had significantly different pricing practices than IOUs.

Finally, considering the technical aspects of the patchwork system—current, voltage, and frequency—current is the most important of these, and the others will not be tested here. Voltage is the least important, since it could be transformed at relatively low cost, as evidenced by the number of utilities that transmit at high voltage and transform to low voltage for delivery to most customers. Frequency is obviously nonexistent for DC utilities, and as a result it is not as pervasive a problem as differences in current; it will be worthwhile examining only if AC is found to have a significant affect upon costs.

Data

There are excellent sources of firm-level data. Foremost is Garcke's manual, which I use here, published annually from 1895 to 1946. This has been entirely untapped by economists and includes balance sheets, income statements, and much other information. Another source is British Parliamentary Papers, which includes every parliamentary order granted to a utility from 1882 to 1919. There were also a series of technical statistics that were published from 1921-1946. I also obtain the population and acreage served by each Parliamentary Order obtained by a utility in my dataset from the 1921 census.

Garcke's Manual was an annual trade publication for the electrical industry in Britain. It is an unusual source that provides a huge amount of information for some utilities, but being a trade publication they could not compel utilities to provide any information. Although it does not present "complete" data for each utility, in general, it is true that the larger the utility, the more information they provide. A noteworthy exception to this is that some of the largest IOUs have complicated corporate structures that involve multiple companies; this renders the data reported unusable, since the different companies each report some of the data needed for this analysis, but none report all; cost data is particularly hard to find in these cases. There are a number of small firms that report little more than generator size and number of customers.

The data is printed in a rather unhelpful format, much of it simply being listed in paragraph form. The balance sheets and income statements have marginal notations and other material that make scanning difficult. All data was input by hand, which places limits on the types of regressions I can perform—for instance, it would take too long to enter the data needed to conduct time series or panel studies.

Looking at Table 3, we see how the regression data set compares with the set of all utilities; the firms used in regressions have an average capacity almost 50 percent larger than all 514 firms that report capacity. Unfortunately, 75 percent of IOUs are lost while only 27 percent of munis are lost, and an even smaller proportion of mixed current munis are lost.

Model: Reduced form cost function

Using data for 1919-20, I estimate a linear, heteroskedastic cross-sectional model with OLS. In the future it may be possible to include data for 1928, since much of the necessary data has already been input for other studies. The dataset includes all utilities in the United Kingdom, including Ireland, that report the data necessary for this analysis.

Since I am investigating the source of inefficiencies in the British electric utility industry, it is convenient to use average operating cost, or average working cost as the British call it, as the dependent variable. A number of independent variables are used, and since some or all of them may vary with the influence of municipal ownership, they are all interacted with an ownership dummy. The model is estimated in the form of a reduced form cost function. Variables indicating variations among firms in system characteristics, capital employment, scale, regulation, and market characteristics are included. Results are detailed in Appendix I.

I find that some of the dependent variables are endogenous and I adopt a simple two-equation, recursive system, which requires that only the first equation be estimated (Kennedy 1992, p158).[6]

Avg. Costs= f(sales, sales^2, load factor, muni dummy and interactions) (Eqn. 1)

Sales = g(population, sales per capita) (Eqn. 2)

Regression results are presented in Table 4. The negative coefficient on sales in combination with the positive coefficient on its square tells us that as sales increase, costs fall then rise, reflecting economies of scale. The coefficient for load factor has a negative sign, telling us that as firms use their capital more intensively they are able to lower their average costs. Two of the muni coefficients are positive and two are negative, so they must be evaluated simultaneously to determine whether IOUs or munis have higher costs.

Notably, maximum price and duration until compulsory purchase were not significant. Utilities with either DC or AC showed no difference in costs, but there were data problems that prevented meaningful results from being obtained for utilities with mixed systems and for those interconnected with other utilities.

[6] Regressing annual sales on population, sales per capita, and their interactions gives an R^2 of 0.85. The slope coefficients are all positive: as population and sales per capita increase, sales increases. See Appendix I for details. As might be expected, load factor is also influenced by these same variables, but more weakly: the R^2 is no more than 0.34; all significant slope coefficients are positive.

Influence of Ownership

To determine whether munis or IOUs are more cost efficient I perform the above regressions with an augmented matrix to predict average operating cost for median firms. I do this by adding an observation with the median independent variables and zero for the dependent variable; I also add an independent variable that is a firm-specific dummy for the added observation. The coefficient and standard error generated for this dummy are the predicted dependent variable and its standard error (Salkever, 1976). I also do this for what I call the 75^{th} percentile firm, which is defined as having the median values of firms with above-median annual sales; in other words, the variables have the median values of the largest 50 percent of firms. It is important to remember that these median values represent just abstract firms. I do this because there are so many small to medium firms in this sample, but we are interested in the larger, low-cost utilities, since they serve more consumers, have lower costs and can be said to represent the future of the electric utility industry. This is a time period when electricity was still developing and demand was increasing rapidly for all utilities. The 75^{th} percentile is still small enough so that we are not solely in the realm of the Manchesters and Birminghams, and there are sufficient IOUs equal to or larger than the median for the results to be worthwhile. Twenty-three IOUs have sales above the 50^{th} percentile value of 7.9 megawatt-hours, ranging up to 42.9 MWh.

The results are presented in Table 5 and show that munis have lower costs at the median and higher costs at the the 75^{th} percentile; thus IOUs are better at taking advantage of economies of scale. In Table 5, I calculate the significance of the difference of the two predictions with the larger of the two standard errors. Using the smaller standard error would obviously result in no change at the median, but it would make the difference at the 75^{th} percentile firm significant at the 99 percent level. There are also some biases in the regression that favor munis. As detailed in the regression results section of Appendix I, the underrepresentation of large IOUs may result in biasing these results toward munis, reporting that they have lower costs than is actually the case. Additionally, there is the uneven regional distribution of the firms, with munis dominating in the north of England, where costs seem to be lower. The trend of relative performance of IOUs improving with scale is significant, since firms were growing rapidly before and during the 1920s.[7] The larger firms are a window on the future, and the view they give suggests that IOUs will become increasingly cost efficient relative to munis as time goes on.

Sources of Inefficiency

Examining the product of the individual variables and their coefficients to determine the economic significance of the different variables, we can see what is the source of the difference in cost efficiency of munis and IOUs. In Table 6, each entry equals the product of the indicated coefficient and the variable at the indicated firm size; the larger the value, the greater its economic significance. In Table 4, we saw that each of these coefficients was significantat the 95 or 99 percent level, but some are so close to zero that they can be said to be of no economic significance. At the median, there are increasing returns to scale and sales squared is not significant, and these scale affects are minor in comparison to load factor. The ownership dummy has a negative sign, and the only interaction term of similar size is that of load factor, which is about one-third smaller; therefore, munis have lower costs at the median. At the 75th percentile, things are almost the same: all nonconstant terms are larger in magnitude, and the relative sizes remain the same except for one. The sum of the interactions for sales and load factor is more than large enough to offset the dummy, and IOUs have lower costs at this larger scale.

So we have seen that the raw data shows munis with substantially lower average costs than IOUs, but economic analysis reveals that IOUs are more cost efficient in some

[7] This trend holds up well in every specification of this model tested. Adding or removing variables had little or no impact on it.

cases. To illustrate this, I evaluate recursive model II for two firms, an IOU and a muni, whose independent variables take the median values (or 75th percentile values) for their respective ownership types (see Table 7). This gives predictions that are fairly close to the observed values and suggests that about 80 percent of the lower costs enjoyed by the municipal firms is due to the differences in scale and load factor. This is particularly interesting because the scale of a utility reflects the market it serves—as stated in the second equation of the two equation model, sales is an increasing function of residential population and industrial and industrial population (the latter proxied by sales per capita)—and the market a utility serves largely coincides with political boundaries, because local councils have the option of providing electricity themselves or permitting an IOU to do so, which means that the observed cost difference is due largely to political decisions made before a single kilowatt has been generated.

Revenue and Cost

IOUs are more cost efficient than munis, but their advantage is masked by the larger size of the munis. This does not entirely put to rest the hypothesis of the failure of private enterprise. As shown in Table 5, IOUs do seem to have higher costs in smaller firms; if these smaller firms are not moving to take advantage of economies of scale, it can still be argued that IOUs show signs of entrepreneurial failure. Whether IOUs are moving to take advantage of economies of scale will be investigated in Chapter 3. It is also possible that munis, even with their high costs, set prices that are more socially beneficial. Specifically, if low-cost IOUs are setting monopoly prices, it is possible that high-cost munis can charge less than monopoly prices and thus be more beneficial to society.

There are a variety of ways to pose this sort of question and test hypotheses. One is to simply run regressions with average revenue, and some are detailed in Appendix II. The results that concern us here are presented in Table 8. Regressing average revenue on average cost and all the variables used in the average cost regressions, we find that only average cost and load factor are significant and a very high R^2 is obtained. Neither the muni dummy nor any interaction terms are significant (see Appendix II). While load factor is statistically significant, it has little impact on the regression and when removed R^2 falls only from 0.85 to 0.83; there may also be some endogeneity since load factor is important in determining costs. In the second regression the coefficient is obviously significantly different from zero, but it is also significantly different from one: average revenue is greater than, not equal to, average cost. Most importantly, we can conclude that IOUs and munis did not differ significantly in their pricing practices.

Price and Behavior

Munis and IOUs appear to be setting prices in the same way, or at least we cannot discern any difference in the relationship between average revenue and average operating cost, but we can ask a more specific question: are these utilities setting monopoly prices? We can test for this by calculating a Lerner index, which gives us the relative profit margin or degree of monopoly, and comparing it with the demand elasticity through the following relationship:

$$\frac{(P-MC)}{P} = \frac{-1}{\varepsilon} \qquad \text{(Eqn. 3)}$$

The reciprocal of elasticity should equal the Lerner index only if the firm is behaving as a monopolist—marginal cost equals marginal revenue. The Lerner index is calculated using average revenue for price and marginal cost calculated using average cost and its relationship to total cost. Since Equation 2 is an identity, we can use the product rule on both sides to find the derivative with respect to Q.

$$TC = AC * Q \qquad \text{(Eqn. 4)}$$

$$MC = AC + \frac{\partial AC}{\partial Q} * Q \qquad \text{(Eqn. 5)}$$

Equation 3 gives us marginal cost in terms of average cost, output, and an average cost function. While the first two are obtained from the raw data, an average cost function is needed to find the derivative, and I use the average cost regression in Table 4:

$$AC = f(1, Q, Q^2, LF, D_{muni}, Q^*D_{muni}, Q^{2*}D_{muni}, LF^*D_{muni}) \qquad \text{(Eqn. 1)}$$

$$\frac{\partial AC}{\partial Q} = f'(1, 2Q, D_{muni}, 2Q^*D_{muni}) \qquad \text{(Eqn. 6)}$$

This average cost function is used for all utilities by evaluating Equation 6 with the appropriate firm-specific data for each utility. Inserting the firm-specific values from Equation 6 into Equation 5 gives us firm-level marginal cost data. In turn, these values are inserted into Equation 3 along with average revenue to yield the Lerner Index for each firm. The median Lerner Index is 0.34.

The elasticity is obtained by a somewhat more complicated method. First, since output varies so strongly with population, the former is adjusted to be proportional to variation in the latter. Adjusted sales is calculated by the following formula:

$$\text{adj. sales}_i = \text{mean sales} * (\text{res. pop}_i/\text{its mean} * 0.67 + \text{ind. pop}_i/\text{its mean} * 0.33) \qquad \text{(Eqn. 7)}$$

The ratio of adjusted sales to mean sales is proportional to the weighted ratio of residential and industrial population to their respective means. With this adjusted sales data, a single, generic, firm-adjusted demand curve can be generated by combining the firm-level point data. This demand curve is used to calculate the demand elasticity from the twenty-fifth, fiftieth, and seventy-fifth percentile firms. The percentiles can be found sorting by either average revenue or by annual sales; I do both and take an average. I measure the change moving from the seventy-fifth percentile to the twenty-fifth, and use the fiftieth percentile (median) for the levels:

$$\varepsilon = \frac{\%\Delta Q}{\%\Delta P} = \frac{(Q_{75} - Q_{25})/\ Q_{50}}{(P_{75} - P_{25})/\ P_{50}} \qquad \text{(Eqn. 8)}$$

The Lerner Index is 0.34, implying an elasticity of -2.92. Using Equation 8 yields an average elasticity of -1.9, and its reciprocal is 0.55, much larger than the 0.34 found for the Lerner index. This tells us that prices are lower than a monopolist could choose:

$$\frac{(P\text{-}MC)}{P} < \frac{-1}{\varepsilon} \qquad \text{(Eqn. 3a)}$$

British utilities have a lower relative profit margin than they could obtain through monopoly pricing. If they chose the monopoly prices calculated from Equation 8, they could increase their prices by almost 50 percent.[8]

Conclusion

Neither munis nor IOUs are behaving as unregulated monopolies, and both set price at the same level relative to cost, but IOUs obtain greater economies of scale, even though they are less cost efficient at small scales. These findings make it difficult to argue that there is a pervasive failure of private enterprise; it can equally be said that it is difficult to argue that there is a pervasive failure of public enterprise. The biases in favor of muni relative efficiency must not be forgotten and suggest that IOUs might have a clearly

[8] This is obtained by inserting the value of the Lerner index calculated in Equation 3, and using algebra to find that the actual price equalled 150 percent of marginal cost at the median. Similarly, the negative reciprocal of the elasticity found in Equation 8 is inserted into Equation 3, and algebraic manipulation shows the hypothetical monopoly price is 220 percent of actual marginal cost. Finally, the ratio of 220 percent to 150 percent is almost 150 percent. This calculation assumes that MC remains constant, which likely will not be true; given economies of scale, raising the price will result in lower output and a higher marginal cost, thus raising monopoly prices even more than this comparison shows, and establishing the calculated value as a floor to the actual increase.

significant cost advantage at larger scale firms. Nevertheless, since IOUs are on average smaller than munis, it is still possible to argue that over time there is a failure of private enterprise to take advantage of scale economies through mergers and bulk purchases of electricity from lower-cost utilities. This will be investigated in Chapter Three.

Although the raw data shows that municipal utilities have lower average costs than IOUs, this is found to be due to differences in the markets served by the two types of utility. Munis owe their apparent advantage to political factors. Local politics in the largest markets of northern England and Scotland often results in the establishment of municipally owned utilities in these markets, and there is nothing IOUs can do to reverse that.

Table 0 Maximum Price in New Orders Granted by the Board of Trade, d/kWh

	Mean	4-5	6	7	8	9	10	12
1890	8.21			1	64	2	5	1
1895	8.00				22			
1900*	7.77		2	18	76			
1905	7.53		4	15	30			
1910	6.73	2	2	2	5			
1914	7.48		7	3	23			
1914-16	7.47	1	2	3	13			

*Fifteen utilities have declining block pricing and are listed at the price of the first block.
Source: British Parliamentary Papers

Table 1 Size distribution of IOUs and munis, annual sales (kilowatthours)

	Munis		IOUs	
	N	%	N	%
0-99,999	4	2	3	4
100,000-499,999	15	8	23	30
500,000-999,000	21	11	14	18
1M to 4.999M	71	36	25	32
5M to 9.999M	38	19	3	4
10M to 49.999M	42	21	9	12
50M to 200M	6	3	0	0

Table 2 Median values, munis and IOUs

	all	IOU	muni
n	274	77	197
Avg. Revenue (d/BTU)	3.03	4.13	2.57
Avg. Operating Costs (d/BTU)	2.16	2.99	1.83
BTUs sold, annually	2,192,825	901,474	3,178,395
Area served (acres)	4651	4265	4735
Population served	46,253	26,261	55,198
Annual sales per capita	48	32	59
Capacity, BTU	2250	854	3000
Peak load, BTU*	1344	533	1919
Load factor, %	19.54	17.13	20.47
Maximum voltage	2000	480	2150
Maximum price	8	8	8
Order granted	1896	1897	1896
Supply commenced	1900	1900	1899
Interconnections, % with	27%	26%	27%
AC only, % with	16%	14%	16%
DC only, % with	39%	56%	32%
mixed, % with	46%	30%	52%
Greater London, n	53	22	31
Yorkshire & Lancashire, n	62	5	57
Scotland, n	18	3	15

*n=271

Table 3 Comparison of Full Data Set with Regression Data Set

n	max volt	capacity	IOUs	munis	AC	DC	mixed	IOU mixed	muni mixed**
571	2389	4597*	303	269	114	314	144	44	100
274	3030	6570	77	197	43	106	125	23	102
regression set as a percentage of full set									
48	127	143	25	73	38	34	87	52	100

* Indicates a figure for the 514 firms that report capacity data.

** This column is not quite right.

Table 4 Average Operating Cost Regression (d/kWh)

	Avg. Op. Costs
Constant	5.9134 ***
	0.3417
Annual Sales	-1.05E-07 ***
	2.96E-08
$Sales^2$	2.08E-15 ***
	7.13E-16
Load Factor	-15.026 ***
	2.102
Muni	-1.452 ***
	0.4441
M*Sales	7.18E-08 **
	3.05E-08
$M*Sales^2$	-1.90E-15 ***
	7.15E-16
M*Load Factor	5.1119 **
	2.51
N	274
R^2	0.56

Note: Standard deviations are reported below coefficients.
OLS; corrected for heteroskedasticity.
*** significant at the 99 percent level
** significant at the 95 percent level
* significant at the 90 percent level

Table 5 Predicted Costs of Munis Relative to IOUs, percent

	median firm	75^{th} percentile firm
recursive model	89^{***}	108

*** IOU predicted cost is significantly different from the muni prediction at the 99 percent level.
Note: the 75^{th} percentile firm has sales of 7.9 million BTUs

Table 6 Economic significance of coefficients for median firms (pence)

	Median	75^{th} percentile
Constant	5.92	5.92
kWh sold	-0.23	-0.83
square kWh sold	0.01	0.13
Load Factor	-2.94	-3.40
Muni	-1.46	-1.46
M*kWh sold	0.16	0.57
M*square kWh sold	-0.01	-0.12
M*Load Factor	1.01	1.16

Table 7 Observed and Predicted Operating Costs, d/kWh

	Observed median	Predicted for median firm	Predicted for 75^{th} percentile firm
IOU	2.99	3.25	2.85
Muni	1.83	2.33	1.83
Predicted difference as % of observed difference	—	79%	88%

Note: IOUs at muni median/75^{th}: 2.52/1.57; munis at IOU median/75^{th}: 2.73/2.53
Predictions are for composite firms.

Table 8 Average Revenue Regressions (d/kWh)

Constant	1.80 ***	0.36 ***
	0.35	0.10
Avg. Operating Costs	1.07 ***	1.23 ***
	0.07	0.05
Load Factor	-5.20 ***	
	1.06	
N	274	274
R^2	0.85	0.83

Note: Standard deviations are reported below coefficients. OLS; corrected for heteroskedasticity. The correlation of average revenue with average operating cost is 0.90.
*** significant at the 99 percent level

Appendix I

Average Cost

The dependent variable in the models I use is average operating cost, or average working cost as the British call it. A number of independent variables are used, and all are interacted with a municipal ownership dummy. These are estimated in the form of a reduced form cost function that has no terms for factor prices, since no information is known about labor costs, and only scattered information is available for capital costs, capital expenditure, and labor expenditure.

The ownership dummy is included to test the hypotheses of a failure of private enterprise and failure of state enterprise. A positive coefficient would indicate that munis have higher costs, thus tending to support the argument that munis were less efficient; a negative coefficient would tend to support the hypothesis claiming a failure of private enterprise. Since the influence of municipal ownership may vary with some or all of the independent variables, the ownership dummy is interacted with all the independent variables, hence one must also consider the influence of the interaction terms in drawing a conclusion about the influence of ownership. I do this by making predictions for median-sized firms with the regression results.

I try to include measures indicating variations among firms in system characteristics, capital employment, scale, regulation, and market characteristics. Due to the fact that some firms reported numerical values of these characteristics and others simply reported their presence, I often use dummy variables to test their influences on average cost.

System characteristics considered were current type and use of current convertors, interconnection with other firms, maximum voltage, and use of batteries. One advantage DC systems had was the ability to use batteries, but almost all utilities with DC used batteries, and the influence of batteries on average cost could not be separated from that of DC current. Similarly, the influence of current convertors could not be measured because having both AC and DC is costly, whether you use a current convertor or maintain two separate systems. Maximum voltage is inversely related to transmission costs, but the greatest differences in maximum voltage tend to reflect the presence of AC transmission, which was possible at much higher voltages; with large numbers of firms employing each current for transmission, the influence of voltage on average cost could not be separated from that of current. In my data this variable tends to be collinear with measurements of maximum voltage employed by the utility. Additionally, due to the way this data is reported in Garcke's Manual, it is not possible to distinguish those firms that do not report any information on the use of batteries or convertors from those that do not have them; in my dataset I may have an unknown number of false negatives for these variables. Results for these three variables are not reported.

The influence of current type and interconnections with other firms did not suffer from these problems, and results are reported below. The presence of direct current should have an influence on costs since it is restricted to lower voltages than alternating current and thus has a higher loss rate. Accordingly, the expected sign of this coefficient is positive. Firms with mixed systems should have higher costs, since they are either operating two physically separate systems or are converting current. The former results in higher costs because scale economies are lost, and the latter results in energy losses during the conversion.

The influence of interconnections is more difficult to ascertain. Although firms that build interconnecting lines with neighboring firms should all see their operating costs fall, that would only be detected with time series data, which I do not have. In a cross-sectional analysis I am comparing the costs of interconnected firms with noninterconnected firms, and for each interconnection there is usually one buyer and one seller.[9] In other words, there is one high-cost firm and one low-cost firm, and Garcke's

[9] Rather than making consistent purchases or sales from their neighbors, some firms used interconnections to engage in load-management activity with their neighbors. From Garcke's Manual, this appears to have been less common than one-way transactions, where one firm consistently purchased and the other

Manual usually does not report enough to determine which firm is which, or even which firm is the other party of the transaction. Some firms sell to more than one high-cost firm, which means there are more interconnected high-cost firms than there are interconnected low-cost firms. Consequently, it is hard to know what to expect from this variable.

Capital employment. There are two measures of capital that are used here, capacity and capacity vintage, the latter being more clearly a measure of the technology employed during this time of rapid technological advance. To be sure, I have only proxies for these two measures. The date of commencement of supply is a proxy for vintage of capital. In the early twentieth century, the most efficient firms would have been those with the biggest and newest generators. Interpretation of this variable is straightforward: I expect this to have a negative coefficient, since the newer the plant, the lower the costs. This actually turns out to be a fairly muddy proxy. A firm with higher capacity is likely to have equipment of more recent vintage. The latter may not be picked up by my proxy for vintage, which measures only the age of the firm and will not pick up the influence of new capacity.

The other important part of a firm's capital is distribution and transmission lines. Few firms provide this data, but there are proxies, such as population density and acreage of the area served. In practice these are disappointing proxies, population density never being significant and acreage never being of any importance in influencing costs even if it is statistically significant. Although these seem disappointing, it may also be the case that these costs are very small, relative to generating costs, or are adequately captured by variables such as population, which are also measuring other influences.

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consistently sold electric current. The annual quantities were also much smaller in these arrangements and would have had a lower impact on costs.

Scale. Cost tends to increase with output, but the presence of scale economies must be considered, so annual sales and its square are included. If scale economies are present, the former should have a negative coefficient, while the latter has a positive coefficient.

Load factor measures the extent to which capital is utilized over time, on daily, weekly, and seasonal bases; one would typically expect this coefficient to be negative if firms are enjoying economies of scale. A high load factor is difficult to obtain, due both to the variation in demand over daily and seasonal time periods and to the need to build excess capacity due to the rapid growth in demand during this period; the highest load factor of the 274 firms I use in regressions is 43%.

Regulation is tested by including a variable containing the maximum price per kWh and a number of dummy variables for various definitions of the terms of compulsory purchase. The former is simple: if the coefficient is significant, then there is effective price regulation, if not, then prices are effectively unregulated. The importance of the compulsory purchase clause, on the other hand, is not so easy to determine.

The importance of duration can be tested by including a variable with the remaining duration from 1919 until the clause can be exercised. This is only a limited test in the sense that it shouldn't make much, if any, difference what the duration is until the remaining portion is just a few years: the average date for the granting of a utility's initial order is 1896, so on average a utility with an unmodified clause will have its term end in 1938, and since only seven utilities in this data received their order before 1889, only seven will have their term expire before 1931. Thus all but seven will have a remaining duration of at least twelve years, with the average being nineteen years. It would be surprising to find this term significant, unless many firms have exceptions to the forty-two year duration, but there are, in fact, relatively few firms with exceptions to this clause included in their parliamentary order, which in itself suggests that this clause was not much of an impediment to entry.

Determining whether exception to the terms of purchase is significant is more difficult and can only be tested with dummy variables, and dozens of combinations of dummies were tested: the results were at best weakly significant, with the sign of the coefficients often being sensitive to the presence of other variables. I do not report any of these results here and conclude that in 1919 compulsory purchase was not a barrier to investment in the electric utility industry, either because so few firms bothered to obtain exceptions to the clause and/or because regression results are not consistent in showing any influence on costs. Dozens of combinations of dummies for duration were also tested with the same result.

Market characteristics included are acreage served, population served, and sales per capita, the latter being a proxy for industrial and commercial population. Population density was also tested, but was not significant. Acreage served is a proxy for distribution and transmission costs; all else being equal, a firm serving a smaller territory should have lower costs. In practice this may be hard to measure, since smaller territories tend to be served by smaller firms, which have higher costs. Population served and sales per capita indicate market size, which largely determines scale economies.

The interaction terms indicate whether municipal costs are influenced differently than IOU costs for the same change in an independent variable. Since there are so many interaction terms, it will be difficult to determine whether munis or IOUs have costs that are in general lower. These regression results will be used to make predictions for costs of some representative firms.

Regression Results

Table A1 shows the regression results for this regression on average cost in columns A and B. Column A is a model that includes all the above-mentioned variables with results I thought worth reporting. Many variables are not significant: date of commencement proves to be a poor proxy for vintage, so I cannot capture technological changes. Direct current and its interaction prove to impact costs no differently than AC, which implies that both IOUs and munis are choosing current appropriately, meaning that large firms are not restricting themselves to DC. Duration is unsurprisingly insignificant. Price cap has no effect on costs, meaning that British utilities are essentially unregulated monopolies. The latter two in combination imply that there is effectively no regulation of electric utilities at least until shortly before the opportunity arises, and even that is uncertain since it cannot be tested with this data.

Problematic terms. The coefficients for mixed systems and its interaction are messy: the noninteracted term is not statistically significant, but the interaction term is significant at the 90 percent level; furthermore, the interacted coefficient is so large that it implies mixed muni firms have lower costs than AC muni firms! For technological reasons, this cannot be true and must be a product of the overrepresentation of mixed muni firms and the underrepresentation of large IOU firms. Since the nonintereacted coefficient is not statistically significant and quite small in magnitude, I see no problem with removing this variable from further consideration.

The coefficient for interconnections is unexpectedly positive, which again, cannot be due to the fact that interconnections raise costs. Rather, it must be a product of the underrepresentation of large IOUs in the dataset. Large low-cost firms are making bulk sales to small high-cost firms, but the investor owned low-cost firms are underrepresented in this dataset, meaning investor owned high-cost firms disproportionately comprise the set of firms with interconnections. The interacted interconnection coefficient is negative enough to push the costs of muni interconnected firms slightly below, but not significantly different from those of noninterconnected firms. Since this coefficient is not measuring what it is supposed to, and that interconnected munis have costs that are not significantly different from noninterconnected firms, I will omit this term from further regressions. Removing these variables may bias the results and show munis to have lower costs than is the case, but the underrepresentation of large IOUs makes this unavoidable.

Surprisingly, capacity is not significant. This is surely due to the fact that it is highly collinear with sales, the two variables having a correlation of 0.93 in the estimated dataset.[10] Sales has a better fit with costs because five utilities have zero capacity and a number of firms with nonzero capacity engage in substantial bulk purchases.

The negative coefficient on BTU sales in conjunction with the positive coefficient on the square of this term reveals that costs appear to follow the familiar pattern of falling, then rising.

The coefficient for load factor is highly significant and has a negative sign, suggesting that as firms use their capital more intensively they are able to lower their average costs; during offpeak hours the marginal cost of additional production is below the average cost of existing production.

Market characteristics have rather mixed results, with only one of the terms for population and sales per capita being significant. This is rather unsatisfying, since these two variables are clearly of crucial importance in determining demand.

The next regression, Column B, attempts to clarify things by removing variables. Most variables are removed because neither the noninteracted nor interacted terms are statistically significant: commencement of operations, DC, capacity, and price cap or maximum price. Two others are removed because of problems with the data, as discussed above: mixed systems and interconnections. There are no major changes, not even in adjusted R^2, which falls very little, from 0.63 to 0.61, particularly if one considers that statistically significant variables were removed. It remains a question as to why the sales per capita and the interacted population terms should not be significant. The latter term may simply indicate that munis are no different from IOUs in this regard, but there is no sound reason why sales per capita should not affect the costs of IOUs, since it must

[10] Regressing annual sales on capacity and a constant has an R^2 of 0.87 with n=303.

affect demand. If sales per capita and population affect demand, they must affect the quantity demanded, which means there is an endogeneity problem.

I tested for this by regressing annual sales on all the other independent variables and interactions except capacity; the R^2 was 0.87 and the adjusted R^2 was 0.86 (see Column C of Table A2). I then removed all the independent variables except population, sales per capita, and their interactions. The results are found in the Column D of Table A2; both the R^2 and adjusted R^2 are 0.85, so these four variables explain most of the variation in annual sales, and the other variables (except capacity) explain essentially none of it. To handle this endogeneity, I adopt a two equation system:

Avg. Costs= f(sales, area, etc., but not population or sales per capita)

Sales = g(population, sales per capita)

Being a recursive system, this is easy to estimate, and I need only estimate the first equation (Kennedy 1992, p158); the results are in Column C of Table A1. The results are similar to Column A, except that neither area nor its interaction are significant, while capacity has become significant. The insignificance of the area coefficient is surprising, because of its influence on transmission costs, but area is positively correlated with sales (0.28), AC (0.26), maximum voltage (0.21), and population (0.38), and transmission costs account for only a minor proportion of operating costs[11], so it is difficult to isolate the influence of area on operating costs with this data. Introduction of population density and sales density were tried to control for some of these, but did not yield significant results. As I did with Column A, I remove nonsignificant and problematic variables and end up with Column D. It is noteworthy that the coefficient for capacity became

[11] On average, generating costs account for 76% of operating costs for the 210 firms that report generating costs.

insignificant after removing these variables, so capacity and its interaction were removed. This gives a straightforward result:

Avg. Costs = f(sales, sales^2, load factor, muni dummy and interactions)

Sales = g(population, sales per capita)

As sales increase, costs fall then rise; as load factor increases, costs fall; and as population and sales per capita increase, sales increase. Two of the muni coefficients are positive and two are negative, and they must be evaluated simultaneously to determine whether IOUs or munis have higher costs.

Table A1

Variable	AVGCOST A	AVGCOST B	AVGCOST C	AVGCOST D
Constant	45.539	5.946	40.327	5.9134 ***
	31.02	0.3146	31.38	0.3417
COMMENCE	-2.10E-02		-1.85E-02	
	1.62E-02		1.63E-02	
DCONLY	7.58E-02		3.53E-02	
	0.2047		0.2313	
ACDC	0.13895		0.14013	
	0.2426		0.2586	
INTER	0.58568 ***		0.37636 *	
	0.2103		0.2181	
BTUSOLD	-1.27E-07 ***	-9.55E-08 ***	-1.12E-07 ***	-1.05E-07 ***
	3.56E-08	3.09E-08	3.40E-08	2.96E-08
BTUSOLD2	4.34E-15 ***	3.02E-15 ***	3.25E-15 ***	2.08E-15 ***
	1.07E-15	7.67E-16	1.01E-15	7.13E-16
CAPACITY	-1.44E-05		-5.82E-05 ***	
	2.60E-05		2.25E-05	
LOADF	-15.495 ***	-14.939 ***	-15.385 ***	-15.026 ***
	1.841	2.005	1.863	2.102
AREA	9.02E-06 ***	8.66E-06 ***	3.92E-06	
	3.40E-06	2.95E-06	5.06E-06	
CENPOP	-4.82E-06 ***	-3.78E-06 ***		
	1.30E-06	1.00E-06		
BTUPOP	-8.99E-04	-5.48E-04		
	5.99E-04	7.65E-04		
MAXP	3.20E-02		0.1	
	0.1151		0.1323	
DUR	1.17E-04		-1.40E-03	
	1.31E-02		1.29E-02	
MUNI	-9.8365	-1.3668 ***	13.141	-1.452 ***
	37.17	0.4136	38.1	0.4441
MCOMMENC	4.57E-03		-7.25E-03	
	1.95E-02		1.99E-02	
MDCONLY	-0.19708		-4.23E-02	
	0.2669		0.299	
MACDC	-0.52838 *		-0.60176 **	
	0.2794		0.3052	
MINTER	-0.71464 ***		-0.53757 **	
	0.2309		0.2417	
MBTUSOLD	1.58E-07 ***	1.36E-07 ***	9.34E-08 ***	7.18E-08 **
	4.00E-08	3.44E-08	3.54E-08	3.05E-08
MBTUSLD2	-4.40E-15 ***	-3.10E-15 ***	-3.12E-15 ***	-1.90E-15 ***
	1.08E-15	7.69E-16	1.01E-15	7.15E-16
MCAP	2.01E-05		4.73E-05 *	
	2.95E-05		2.42E-05	
MLOADF	9.3786 ***	7.9303 ***	7.251 ***	5.1119 **
	2.228	2.357	2.312	2.51
MAREA	-1.92E-05 ***	-2.05E-05 ***	-1.07E-05	
	6.53E-06	6.11E-06	7.60E-06	
MCENPOP	1.16E-06	-4.49E-07		
	1.71E-06	1.46E-06		
MBTUPOP	-8.45E-03 ***	-9.95E-03 ***		
	1.93E-03	2.12E-03		
MMAXP	-6.79E-02		-0.17071	
	0.1483		0.164	
MDUR	1.62E-02		2.53E-02	
	1.55E-02		1.55E-02	
n	274	274	274	274
R2	0.67	0.63	0.616	0.555
Adj R2	0.63	0.61	0.581	0.543

Table A2				
Variable	BTUSOLD A	BTUSOLD B	BTUSOLD C	BTUSOLD D
Constant	3.37E+07	-7.16E+05	1.15E+08	-1.47E+06 ***
	9.93E+07	4.59E+05	1.05E+08	3.15E+05
COMMENCE	-18601		-62949	
	5.21E+04		5.52E+04	
DCONLY	3.44E+05		-1.05E+06	
	7.67E+05		1.12E+06	
ACDC	-1.76E+05		-7.92E+05	
	1.10E+06		1.54E+06	
INTER	96374		-1.21E+06	
	7.78E+05		1.11E+06	
CAPACITY	737.53 ***	1455.1 ***		
	120	31.84		
LOADF	1.01E+07 *		1.57E+07 **	
	5.44E+06		7.75E+06	
AREA	17.274		-13.702	
	13.31		19.78	
CENPOP	16.799 ***		53.234 ***	53.807 ***
	5.294		3.642	4.826
BTUPOP	15145 ***		27900 ***	29383 ***
	2312		5444	5731
MAXP	-1.93E+05		2.28E+05	
	2.73E+05		4.02E+05	
DUR	13176		-7902.4	
	2.30E+04		3.34E+04	
MUNI	-3.16E+08		-3.48E+08	-8.96E+06 ***
	2.21E+08		2.91E+08	1.85E+06
MCOMMENC	1.63E+05		1.78E+05	
	1.15E+05		1.53E+05	
MDCONLY	1.96E+06		3.95E+06 **	
	1.32E+06		1.99E+06	
MACDC	3.24E+05		-19040	
	1.55E+06		2.17E+06	
MINTER	4.78E+05		-5.37E+05	
	1.16E+06		1.67E+06	
MCAP	151.32			
	281.9			
MLOADF	-2.14E+07 **		-5.17E+07 ***	
	1.07E+07		1.83E+07	
MAREA	7.0032		101.13 *	
	56.85		58.35	
MCENPOP	54.693 **		79.043 ***	73.495 ***
	21.76		14.76	14.35
MBTUPOP	10988		1.03E+05 ***	71376 ***
	1.51E+04		2.54E+04	1.82E+04
MMAXP	6.60E+05		4.51E+05	
	1.05E+06		1.31E+06	
MDUR	26575		1.90E+05 *	
	9.38E+04		1.12E+05	
n	274	274	274	274
R2	0.93	0.87	0.87	0.85
Adj R2	0.93	0.87	0.86	0.85