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# Economies and Diseconomies: Estimating Electricity Cost Functions

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# ECONOMIES AND DISECONOMIES: ESTIMATING ELECTRICITY COST FUNCTIONS

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**Abstract:**
This paper presents estimates of the variable cost function of electricity generation. The cost function is estimated using a two dimensional definition of capacity utilization. Because electricity cannot be conveniently stored, generation facilities follow the load across demand cycles. Capacity utilization can be captured empirically in two ways. One is generation relative to capacity when a unit is connected to the system; the other is the percent of time the unit is disconnected. The estimated cost function shows that both dimensions affect average cost, which generally declines as capacity utilization increases.

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## I. Introduction

Estimation of the cost function for electricity generation has always intrigued economists.[1] Numerous papers have explored virtually every nuance of the problem. One reason for this is the fact that relatively good plant and firm level data have historically been available from reports that regulated utilities are required to file with the federal government and before state regulatory commissions. Also, the electric industry is big and therefore worthy of attention by economists. Industry revenues in 1998 were $217 billion.

Simple, single equation models have been fit and more complicated multi-equation estimating techniques were pioneered with application to electricity production. Technological progress has always been a focus; both simple and sophisticated models have been used to examine the effect of technological progress on cost per kwh of electricity.[2] Even engineering-style estimates have been presented.[3] Electric production has been studied from the firm level and at the plant level.[4]

All of the prior research on electricity cost has focused on average total cost, that is, the sum of capital and operating expenditures. The advent of electricity competition calls for another level of analysis. A central question in forecasting the price of electricity in the restructured electric industry is how expanded capacity utilization of existing plants will affect the cost of production and thereby the competitive equilibrium price. Instead of extensively examining the capital cost issue, operating costs have become more important.

Moreover, the competitive supply of electricity highlights a dimension of cost that has not been explored by prior research. Analysts have examined the effect of capacity utilization on cost, but this has been done using a one dimensional definition of capacity utilization. In fact, capacity utilization has two fundamental components. One reason that capacity is less than fully utilized is because plants are idled many times during the year when load demand falls off. The other factor that reduces capacity utilization is that plants which stay connected to the load are cycled throughout the day and week as load demand varies. This is called “load following.” Competition will increase capacity utilization in both these dimensions. Hence, it is important to consider production costs in this light.

The analysis presented in this paper examines the average variable cost function for electric generation in terms of multidimensional capacity utilization. Plant level data on operating costs are used to estimate cost. Estimation is confined to conventional steam generation, and the estimates for coal-fired units are compared to the estimates for gas- and oil-fired boilers. These are the base load units of the electricity system that have been under utilized in the regulatory regime and from which we expect competition will draw forth additional output.

The estimates presented here indicate that the average variable cost of all conventional steam units shows substantial economies as capacity utilization increases and only modest

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[1] Cowing and Smith (1978) review the literature of the sixties and seventies. Following that, see Stewart (1979), Stevenson (1980), Joskow and Schmalensee (1983), Betancourt (1986), Betancourt and Edwards (1987), and Nelson (1989).

[2] Barzel (1963), Stevenson (1980).

[3] Stewart (1979).

[4] Cowing and Smith discuss this aspect of the problem, especially in their review of Christensen and Greene (1976). Both firm and plant level analyses have certain appealing features. System-wide cost can be used to answer the question of economies of scale from the perspective of natural monopoly within a utility service territory. Analysis of generating units themselves is useful in determining the margin of capital expansion.

diseconomies in a few cases. This result is robust. Importantly, economies of capacity utilization are very quickly exploited in the load following dimension. Across plant sizes, gas and oil units show some diseconomies for very large units. However, this effect is small. Generally, higher capacity utilization causes average variable cost to decline.

## II. The Choice of the Dataset

Cost data for the majority of electric generating plants in the country are available from information filed by investor-owned utilities on the Federal Energy Regulatory Commission (FERC) Form 1.[5] Investor-owned utilities are required to report annually the original capital and operating costs cost of each major generating facility. For our purposes, the important information available from Form 1 is the total expenditure on operations and maintenance, expenditures on fuel and the primary fuel type, expenditures on engineering and supervision which are the principal component of labor costs, generation output, generation capacity, number of units, and the number of hours during the year that the units at the facility are connected to the load. Data for the years 1995 and 1996 are used.

Only conventional steam generating units fueled by coal, gas, and oil are examined.[6] Conventional steam generation makes up around two-thirds of total production nation-wide. Conventional steam generators are used as the middle range of generation capacity for most utilities. They are base load units but also used for load-following. That is, they are ramped up and down throughout the day. When electricity demand falls off during the seasonal cycle conventional steam units are idled.[7]

Over 1000 conventional steam units are reported in FERC Form 1 data for 1995 and 1996. Many of these units are jointly owned among several utilities. Data from Department of Energy, Energy Information Agency (DEO-EIA) Form 860 was cross referenced to the Form 1 data to reconcile the reporting inconsistencies. For many units, this reconciliation is impossible. For instance, when a co-owner is not an investor-owned utility, complete operating data on the unit is not generally available. Other reporting inconsistencies exist in the data. Installed generation capacity reported on Form 1 does not always match the data reported on Form 860. Whenever the capacity reported on Form 1 differed by more than 20 percent from Form 860, the facility was excluded from analysis. In the end, the sample contains 514 observations on coal-fired and 261 observations on gas and oil facilities.

It is common for electric generation facilities to have multiple generators at one site. These data are reported in DOE-EIA Form 860. In the final sample used in this study, the number of units at one facility varies between one and eight. The operating cost data are most commonly reported for the facilities and not by unit. To accommodate this reporting phenomenon, cost and generation are divided by the number of generators so that the comparison of operating cost and

[5] Form 1 data has traditionally made up the base data used to estimate electricity production cost. Historically these data were first published by the Federal Power Commission and then by the Department of Energy. Data used in this study come directly from the Form 1 filings available from the FERC.

[6] There are some conventional steam units around the country that are fired by other fossil fuels such as wood chips and lignite. However, the numbers of these units are too few to include them in the estimating process.

[7] Engineering characteristics are said to make oil and gas units ramp more cheaply than coal units. Coal is harder to burn. If a coal unit is ramped down too far, the coal stops burning and the boiler must be fired with more expensive starter fuel. One of the objectives of this research is to investigate this assertion.

scale is made based on the size of the individual generating unit. The number of generators is then used as a weight in the regression to account for the heteroskedasticity created by this averaging process for facilities with multiple units.

Fuel costs are reported directly on Form 1. Labor's share of cost is calculated as the sum of the expenditure categories "Operation Supervision & Engineering" and "Maintenance Supervision & Engineering" divided by total operating costs. The wage rate is calculated as total salary and wages for each firm divided by the total number of workers. Where plants are co-owned, the wage rate for the operating company is used.[8]

## III. The Choice of the Specification

There is a substantial amount of excess generating capacity in the electric industry. Excess capacity is a predictable effect of regulation.[9] However, in conjunction with the integrated power grid, this excess capacity becomes the spur of competition. Most observers expect that competition will increase capacity utilization rates in electric generation just as it has done in every other deregulated industry. Capacity utilization has been around 50 percent for the regulated electric industry, and this is approximately the same level of under utilization that was observed in the airline industry prior to competition.[10] It is conceivable that that capacity utilization in the electric industry will rise above 70 percent, possibly above 80 percent.

It is true that capacity utilization of 70-plus percent for all units will depend on shifts in load profiles. The Averch-Johnson/Wellisz criticism of regulation argues that utilities eschew peak load pricing in order to increase their return. Competition will presumably price in a way that encourages load smoothing. Hence, higher capacity utilization is predicted. Nonetheless, there is a partial equilibrium prediction as well. To the extent that variable costs fall with capacity utilization, competition will set price at something like the 75 percent capacity utilization rate and plants that cannot make the cut will be mothballed and written off.

Capacity utilization or load factor has been addressed in the literature.[11] Betancourt and Edwards summarize the issue by a three part taxonomy. One treatment includes capacity utilization as a state of nature. In this approach, it is exogenous to the choice set of the firm, but still affects cost. The second approach treats capacity utilization as a measure of the duration of operations. Capacity utilization affects the cost of capital in inverse proportion. The cost function is expressed as a function of capacity rather than output. Finally, capacity utilization is modeled as a measure of speed. Here again capacity utilization affects the price of capital but also enters the cost function by changing the level of output.

These three alternative treatments all focus on the question of the behavior of the firm in choosing the level of capital to employ. That is not the issue investigated in this research, and

[8] This definition of the wage rate was suggested by a referee based on the fact that workers at generating plants are unionized and the same wage applies company-wide. The wage rate estimates are averaged across 1995 and 1996. Unfortunately it is hard to calculate a plant specific wage rate. In earlier versions, the wage rate in manufacturing in the county where the plant is located was used instead of a utility specific wage rate. This wage rate data came from County Business Patterns. Alternative definitions of the wage have little effect on the estimates.

[9] See Averch and Johnson (1968) and Wellisz (1969).

[10] See Maloney, McCormick, and Sauer (1996).

[11] Huettner and Landon (1978), Stevenson (1980), Betancourt (1986), Betancourt and Edwards (1987), Nelson (1989).

hence, many of questions addressed by Betancourt and Edwards do not apply. The question posed in this research is simply to determine what will happen to operating cost as the firm expands generation output from an individual generating unit. We observe cost and the various dimensions of output across generating units and then try to estimate the underlying relations.

One aspect of cost that has not been incorporated into the prior literature is the multiple dimension of capacity utilization. Capacity utilization has taken on a very simple definition in previous cost studies, that is, annual generation output divided by maximum possible output over the year. The productive capacity of a generator is measured in terms of the highest instantaneous level of electricity output in megawatts (MW) that the unit can produce. Cumulative output is the sum of generation output over the year measured as megawatt-hours (MWh). The definition of capacity utilization used in prior research is:

$$\frac{\text{MWh}}{\text{MW} \times \text{Total Hours in the Year}}.$$

Obviously this is simplistic. More reasonably operating cost is a function of the continuous time path of output over the year, not just the cumulative amount relative to maximum potential. However, estimating cost as a function of the continuous time path of output would require a level of data gathering that is beyond the scope of most academic research. As an alternative, we attempt to model the time path of production in a parsimonious fashion given available data. To do this, we focus on the two strikingly different ways that plants operate at less than full capacity.

Sometimes generators are disconnected from the load and shut down. This happens in the seasonal off-peak when total system load demand will not require some units to be dispatched. At other times, units remain connected to the load, but produce electricity at a level that is less than their maximum capacity. Units ramp up and down following the load cycle over the day and week. When load demand is high during the day, units ramp up toward their maximum potential. At night, they ramp down producing much less than maximum generator output. The first effect we call *intermittent idling*; the second effect will be labeled *load following*.

Data reported on Form 1 allow us to proxy these two effects. Utilities report the number of hours that each unit is connected to the load during the year.[12] Call this $H$. $H$ compared to the total hours in the year, $T$, is a measure of intermittent idling, $h$. That is,

$$h = \frac{H}{T}$$

As $h$ increases, the unit is connected to the load a larger portion of the year and intermittent idling goes down.

Load following can then be proxied by the total output of the unit over the year compared to the maximum possible output produced *when it is connected to the load*. Let $K$ represent the maximum generator capacity (MW) of a unit and $q$ stand for cumulative annual output (MWh). Our load following variable is a modified measure of capacity utilization:

[12] These data do not identify whether the plant is in spinning reserve or actually producing during these hours. Similarly, we do not know the status of the plant when it is disconnected. It may have a cold or warm boiler which will affect cost as well as the speed at which it can be brought back on line.

$$u = \frac{q}{K \cdot h \cdot T}$$

Load following goes down as $u$ approaches one. The more closely a unit operates to its full potential during the hours of the year that it is connected to the load, the less it is being ramped up and down over the load cycle.

To estimate the impact of capacity utilization in both the dimension of load following and intermittent idling, the standard translog cost model is adapted in the following way:

$$\begin{aligned}
\ln C &= \alpha_0 + \alpha_q \ln q + \alpha_u \ln u + \alpha_h \ln h + \sum_i \alpha_i \ln w_i \\
&+ \frac{1}{2}\gamma_{qq}(\ln q)^2 + \frac{1}{2}\gamma_{uu}(\ln u)^2 + \frac{1}{2}\gamma_{hh}(\ln h)^2 \\
&+ \gamma_{qu} \ln q \ln u + \gamma_{qh} \ln q \ln h + \gamma_{uh} \ln u \ln h \\
&+ \sum_i \gamma_{qi} \ln q \ln w_i + \sum_i \gamma_{ui} \ln u \ln w_i + \sum_i \gamma_{hi} \ln h \ln w_i \\
&+ \frac{1}{2}\sum_i \sum_j \gamma_{ij} \ln w_i \ln w_j
\end{aligned} \tag{1}$$

where $w_i$, $i$={1,3}, is the price of fuel, labor, and all other operating expenses. The model includes the three dimensions of output including squared and interaction terms. Plant capacity is indirectly included in the specification in the definition of $u$.

The derivative of the log of cost with respect to the log of an input's price is the input's share of cost based on the envelope theorem. Thus, equation (1) identifies three other equations, which are the cost shares of the inputs. These equations are simultaneously estimated along with equation (1) and the cost shares are additional data embodied in the estimated parameters.

Note that homotheticity and homogeneity of the underlying production function are not restrictions on the estimating form though they may be observed empirically. Homotheticity is revealed when $\gamma_{ki} = 0$ for all $i$ and $k=\{q, h, u\}$. Homogeneity requires that $\gamma_{kk} = 0$ as well.

Economies and diseconomies of scale are less important in the consideration of variable cost than with total cost. Even so, this issue poses a natural curiosity. Normally, the derivative $\frac{\partial \ln C}{\partial \ln q}$ is used characterize the existence of economies and diseconomies of scale. This is the elasticity of cost with respect to generation and is the ratio of marginal to average cost. Average cost is declining when this ratio is less than one and increasing when the ratio is greater than one. The cost function specified in eqt. (1) complicates the matter of economies of scale somewhat. Increases in output, $q$, can come in the form of larger facilities or more intensive use of smaller facilities. We are interested in the shape of the cost function on all margins.

Consider average cost for a given plant size depicted in terms of both capacity utilization dimensions: load following and intermittent idling. Such cost functions are shown for the estimated equations later in the paper. In such a picture, output increases as the plant does less load following and as the plant does less intermittent idling. Average cost is potentially U-shaped in either dimension. The minimum of average cost can be found by looking at the envelope of average cost along the optimal expansion path of output through load following and intermittent idling space.

The same picture can be reproduced for each plant size. Economies of scale can be captured as the envelope of the minima of average cost in load following and intermittent idling space across plant sizes. The empirical representation of this is depicted in the empirical section.

There are many ways that the cost function might be specified. No doubt, equation (1) has some superfluous terms that may cause the sampling error on the estimates to be large. However, its chief advantage is that it allows average cost to be U-shaped in all possible dimensions: generation, load following, and intermittent idling. The specification shown in equation (1) is used because it maps into the current literature more directly and while annual energy and connect time are outputs, capacity is not and yet capacity utilization is.[13] We want to measure the effect on cost of a change in capacity utilization and equation (1) does this.[14]

Notice that if $h$ =1 then the cost function has the same form as in Betancourt and Edwards model I. More generally, the specification in equation (1) follows the same spirit as Stevenson by treating both dimensions of capacity utilization as state of nature variables. Thus, the work presented here can be thought of as a generalization of earlier literature.

## IV. The Estimates

The cost function shown in equation (1) is estimated as a system of equations along with $n$-1 of the share equations. The omitted input is Other Expenses. The estimation procedure is iterative seemingly unrelated regressions. The parameter restrictions of the translog model mean that we need only report the cost function because the share equations are made up of parameters found in the cost function. This restriction is imposed in the estimating procedure.

To benchmark the estimation process it is useful to examine a simple plot of the data. Figure 1 shows average cost as a function of annual generation. The entire sample of coal, gas and oil plants are pictured here. There is a pronounced and obvious downward slope to average cost. The picture of average cost and generation suggests the possibility that average cost turns up as output expands which is something that we hope to more precisely assess in the estimation process.

[13] The threefold specification of output could be rewritten from MWh, $h$, and $u$, to MWh, MW, and total hours connected to the load. Since these transformations are multiplicative, they will not change the estimated parameters.

[14] Operation of plants in a regulated utility's system is endogenous. Increasing output may increase or decrease overall costs for the utility. However, this effect is in reference to total costs including capital cost recovery. For instance, if demand increases, average total costs may be lowered by building another base load plant rather than increasing production at units already in service. This effect does not bias the estimate of average variable cost drawn from data that reflect variation across systems based on loads that are slightly larger or slightly smaller than the optimum for capacity portfolio of each system.

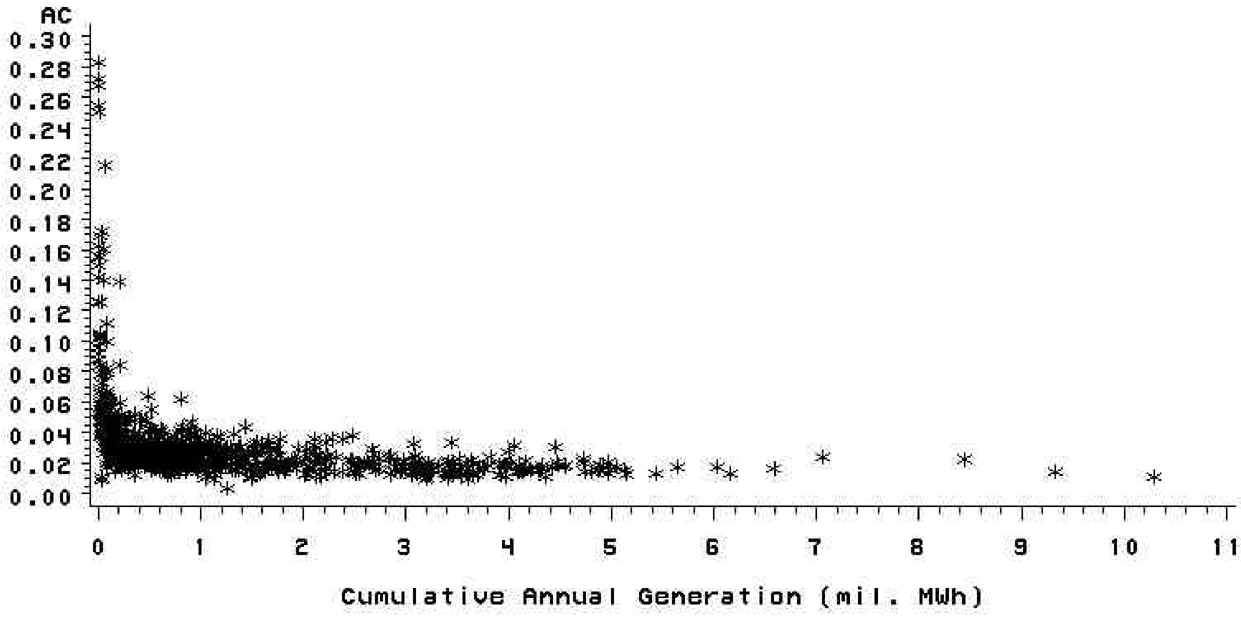


Figure 1: Plot of the Raw Data

Summary statistics for the samples used in the estimation are given in Table 1 and Table 2. Capacity ranges from very small units, 9 megawatts, to very large ones, 1426 MW. Coal units are slightly larger than gas and oil on average. The respective means are 321MW and 268MW. Gas and oil plants do more load following compared to coal plants, .6 versus .876, and more intermittent idling, .4 compared to .6. As a consequence the average annual generation output of coal plants is higher than gas and oil units, 1.6 million compared to .6 million MWh per unit.

**Table 1**
**Summary Statistics on Coal-Fired Conventional Steam Generation**

| | mean | std. dev. | min | max |
|---|---|---|---|---|
| *Observations:* | 514 | | | |
| Average Variable Cost | $ 0.024 | $ 0.013 | $ 0.004 | $ 0.170 |
| Fuel's Share of Cost | 0.719 | 0.120 | 0.152 | 0.948 |
| Labor's Share of Cost | 0.039 | 0.032 | 0.001 | 0.419 |
| Net Annual Generation | 1.618 | 1.552 | 0.010 | 10.297 |
| Load Following | 0.876 | 0.190 | 0.044 | 1.000 |
| Intermittent Idling | 0.589 | 0.175 | 0.111 | 0.967 |
| Price of fuel | $ 1.46 | $ 0.42 | $ 0.49 | $ 3.43 |
| Wage Rate | $ 40 | $ 7 | $ 20 | $ 72 |
| Generator Capacity | 321 | 258 | 12 | 1426 |
| Number of Units | 2.7 | 1.4 | 1.0 | 8.0 |

Notes: Data from FERC Form 1 for 1995 and 1996. Average variable cost in dollars per kilowatt-hour. Net generation in millions of megawatt-hours. Capacity in megawatts. Price of fuel in dollars per million btu. Wage Rate in $1000 annual. Load following and intermittent idling decrease with higher values.

**Table 2**
**Summary Statistics on Gas & Oil Conventional Steam Generation**

| *Observations:* 261 | mean | std. dev. | min | max |
|---|---|---|---|---|
| Average Variable Cost | $ 0.049 | $ 0.042 | $ 0.018 | $ 0.283 |
| Fuel's Share of Cost | 0.738 | 0.176 | 0.123 | 0.964 |
| Labor's Share of Cost | 0.041 | 0.051 | 0.001 | 0.628 |
| Net Annual Generation | 0.601 | 0.647 | 0.001 | 3.998 |
| Load Following | 0.600 | 0.306 | 0.012 | 1.000 |
| Intermittent Idling | 0.409 | 0.165 | 0.012 | 0.821 |
| Price of fuel | $ 2.62 | $ 0.66 | $ 1.34 | $ 5.03 |
| Wage Rate | $ 41 | $ 7 | $ 28 | $ 69 |
| Generator Capacity | 268 | 218 | 9 | 902 |
| Number of Units | 2.5 | 1.3 | 1.0 | 7.0 |

Notes: Data from FERC Form 1 for 1995 and 1996. Average variable cost in dollars per kilowatt-hour. Net generation in millions of megawatt-hours. Capacity in megawatts. Price of fuel in dollars per million btu. Wage Rate in $1000 annual. Load following and intermittent idling decrease with higher values.

Average operating cost varies from .4¢ to 17¢ per kWh for coal fired plants and up to 28¢ for gas and oil plants. The simple average across coal plants is 2.4¢/kWh while gas and oil plants have somewhat higher costs at 5¢/kWh. This difference is largely made up by the average cost of fuel. The average price of coal per btu is $1.46, while oil and gas is $2.62. The elasticity of average cost with respect to fuel price is the share of cost made up by fuel. This is .72 for coal and .74 for gas and oil plants. Based on this, if gas and oil prices per btu fell to the level of coal, average cost for gas and oil plants would be around 3¢/kWh given their average load following and intermittent idling.

Table 3 shows the distribution of capacity, load following, intermittent idling, and annual generation for the two subsamples. Generator capacity is very similar between the two samples. There are a few more really big coal plants than gas and oil. Gas and oil plants do more load following than coal units. In part, this may be due to the fact that when they are connected to the load, there is higher variance in consumption due to seasonal factors.[15] The striking fact shown in Table 3 is the extent of the year that gas and oil plants are idled. Ninety percent of the coal plants are connected to the load 60 percent of the year, while only around half of the gas and oil plants are running this often. No doubt this is due to the fact that gas and oil plants have higher operating costs.

[15] Data on load profiles by unit by season are not readily available.

**Table 3**
**Distribution of Capacity and Capacity Utilization**

| | *Min* | *10th %tile* | *25th %tile* | *Median* | *75th %tile* | *90th %tile* | *Max* |
|---|---|---|---|---|---|---|---|
| **Coal Plants** | | | | | | | |
| Generator Capacity | 12 | 63 | 121 | 231 | 512 | 679 | 1426 |
| Load Following | 0.111 | 0.347 | 0.457 | 0.595 | 0.714 | 0.819 | 0.970 |
| Intermittent Idling | 0.044 | 0.633 | 0.849 | 0.957 | 1.000 | 1.000 | 1.000 |
| Annual Generation | 0.01 | 0.16 | 0.47 | 1.00 | 2.59 | 3.91 | 10.30 |
| **Gas & Oil Plants** | | | | | | | |
| Generator Capacity | 9 | 55 | 100 | 207 | 372 | 579 | 902 |
| Load Following | 0.012 | 0.190 | 0.284 | 0.403 | 0.523 | 0.636 | 0.821 |
| Intermittent Idling | 0.012 | 0.127 | 0.362 | 0.671 | 0.874 | 0.980 | 1.003 |
| Annual Generation | 0.001 | 0.03 | 0.13 | 0.41 | 0.87 | 1.44 | 4.00 |

The translog parameter estimates are shown in

Table **4** for both coal and gas/oil plants. The translog model fits the data very well for both samples. The $R^2$ for the coal plants is .97 and .93 for the gas and oil units. These $R^2$s are system weighted averages for the cost function and the ($n$-1) share equations. Some of the estimated coefficients are not statistically different from zero. However, of the 20 cost function parameters, 16 of the estimates are statistically significant at the 10 percent level or greater in the coal subsample and 12 in the gas and oil subsample. The estimated cost function and implied production process are not homothetic as evidenced by the fact that most of the cross product terms between input prices and output are non-zero; if the production function were homothetic, these terms would be zero. Furthermore, all three dimensions of output, $q$, $u$, and $h$ have coefficients on some terms that are statistically significant implying that all three dimensions are affecting cost at some margin. No dimension of output is superfluous empirically.

The implied demand elasticity for fuel at coal plants is -.07 and for labor, -.68. At gas and oil plants, both inputs are more elastically demanded. The fuel price elasticity is -.26 and the wage elasticity is -.96.[16]

Because output varies in three dimensions, we want to know how average cost varies in these ways. Bigger plants have the capacity to produce more output, and for a given plant size, output increases as capacity utilization increases as a result of less intermittent idling and less load following. To depict how this is revealed in the estimates, we start with three dimensional graphs of average cost and the two dimensions of capacity utilization—load following and intermittent idling.

[16] These price elasticities are calculated as the coefficient on the squared price term divided by the input's cost share plus the cost share minus one. To the extent that the estimated coefficient is not different from zero as is the case for gas and oil plants, price elasticity is the cost share minus one. The fuel price elasticity at coal plants is close to, but statistically different from zero.

**Table 4**
**Estimated Parameters for Translog Cost Function & Share Equations**

| | *Coal* | | *Gas & Oil* | |
|---|---|---|---|---|
| | Parameters | t-stats | Parameters | t-stats |
| Intercept | -4.019 | -12.962 | -5.395 | -5.935 |
| *Linear Terms* | | | | |
| Cumulative Output (*q*) | 0.875 | 39.426 | 0.925 | 19.756 |
| Load Following (*u*) | -0.019 | -0.250 | 0.175 | 1.830 |
| Intermittent Idling (*h*) | 0.064 | 0.793 | 0.036 | 0.396 |
| Fuel Price (*f*) | 0.984 | 22.602 | 1.079 | 10.125 |
| Wage Rate (*w*) | -0.083 | -1.409 | 0.159 | 0.913 |
| *Squared terms* | | | | |
| Cumulative Output (*q*) | 0.094 | 8.295 | 0.087 | 3.723 |
| Load Following (*u*) | 0.109 | 1.431 | 0.082 | 1.327 |
| Intermittent Idling (*h*) | 0.621 | 7.082 | 0.144 | 2.059 |
| Fuel Price (*f*) | 0.152 | 14.696 | 0.011 | 0.535 |
| Wage Rate (*w*) | 0.011 | 2.008 | -0.014 | -0.865 |
| *Interaction Terms* | | | | |
| *qu* | -0.065 | -2.677 | -0.012 | -0.372 |
| *qh* | -0.204 | -6.680 | -0.089 | -2.665 |
| *uh* | 0.138 | 2.035 | 0.102 | 1.950 |
| *fq* | 0.023 | 5.533 | 0.048 | 6.996 |
| *fu* | 0.096 | 8.264 | 0.054 | 4.508 |
| *fh* | 0.130 | 9.822 | 0.081 | 6.573 |
| *wq* | -0.004 | -2.875 | -0.004 | -1.030 |
| *wu* | -0.009 | -2.236 | -0.025 | -3.958 |
| *wh* | -0.017 | -3.720 | -0.026 | -4.182 |
| *fw* | -0.022 | -5.324 | -0.016 | -1.487 |
| | | | | |
| Number of Observations | 514 | | 261 | |
| Mean Squared Error | 0.06 | | 0.11 | |
| Weighted R-squared | 0.97 | | 0.93 | |

Notes: Parameters are reported as they appear in the cost function. See equation (1). Cost data from FERC Form 1 for 1995 and 1996. Cost and cumulative output divided by number of generating units at each facility. Regression weighted by number of units at each facility. Cost function is estimated simultaneously with share equations for labor and fuel cost using iterative seemingly unrelated regressions. Mean square error is for cost equation.

Figure 2 and Figure 3 show average cost for two different sizes of coal plants, 100 and 800MW, respectively.[17] Figure 4 shows average cost for 800MW gas and oil plants. The relation across sizes of units is similar between the fuel types. Hence, only the picture for larger oil and gas units is shown. There is a pronounced decline in average cost as output increases due to increased capacity utilization. The graphs show no demonstrable evidence that average cost turns up, though we will investigate this more in a moment. On the margin of load following, holding $h$=1 and varying $u$ from .25 to .75, average cost declines by 25 percent for a 300MW coal unit and by 16 percent for gas and oil units. (This elasticity is higher for smaller units and slightly

[17] Average cost is obtained from the forecast of total cost for each output level. This forecast is derived using the standard transformation of the mean of the log normal distribution.

smaller for larger plants.) This means that it is less costly to ramp gas and oil units. On the margin of intermittent idling, holding $u$=1 and varying $h$ from .25 to .75, average cost declines by 58 percent for a 300MW coal unit and by 33 percent for gas and oil units.

Figure 2 and Figure 3 show that the economies associated with intermittent idling are more pronounced for larger units. This is seen by the fact that the average cost function dips more slowly on this margin for big plants than for small. The graphs also show that it is relatively less expensive to load follow with big plants rather than small. In other words, the economies associated with running the plant at a more constant output when it is connected to the load are exhausted more quickly for big plants than small. This is a rather surprising result but it means that for big units it is more important to keep the plant connected to the load even if it is ramped up and down as a consequence.

Economies of scale are best displayed by looking at the minimum average cost for each plant size. Table 5 shows the forecast of minimum average cost for various capacities and levels of capacity utilization in both the load following and intermittent idling dimensions. These are the minima of forecast average cost across plant sizes and at the most efficient capacity utilization. The coal plants display the expected result. Average cost is achieved at full capacity utilization at all but the smallest plant sizes. This means that costs decline with higher capacity utilization in almost all cases. Average cost reaches its minimum across plant sizes at about the average plant size and is flat at this level for larger plants. The forecast minimum average cost overall is 1.7¢ per kWh. This compares to an observed average cost of 2¢ for these plants, that is, 300MW units or bigger operating at 65 percent load following and connected to the load 92 percent of the time. Thus, increase capacity utilization of these units can be expected to reduce cost by around 15 percent.

The forecasts for the gas and oil plants show some modest U-shape in minimum average cost across plant sizes. For plants using these fuels, the mid-sized units have the lowest cost at 2.6¢ per kWh and cost increases by 2 mills to 2.8¢ for the largest. It is also the case that minimum average cost for the larger plants actually occurs for capacity utilization less than 100 percent in the load following dimension. However, as can be seen in Figure 5 this is an extremely modest effect. Average cost is essentially flat for load following of 50 percent or more when the unit is connected to the load 100 percent of the time.

While the shapes of the cost curves estimated for units burning coal compared to gas and oil are slightly different, the basic result is the same. Capacity utilization is an important determinant of cost. This is most especially the case in terms of intermittent idling: Disconnecting the unit from the load raises cost and more for big plants than small. The major difference between the lowest cost that can be achieved at coal plants compared to gas and oil is the cost of the fuel itself.

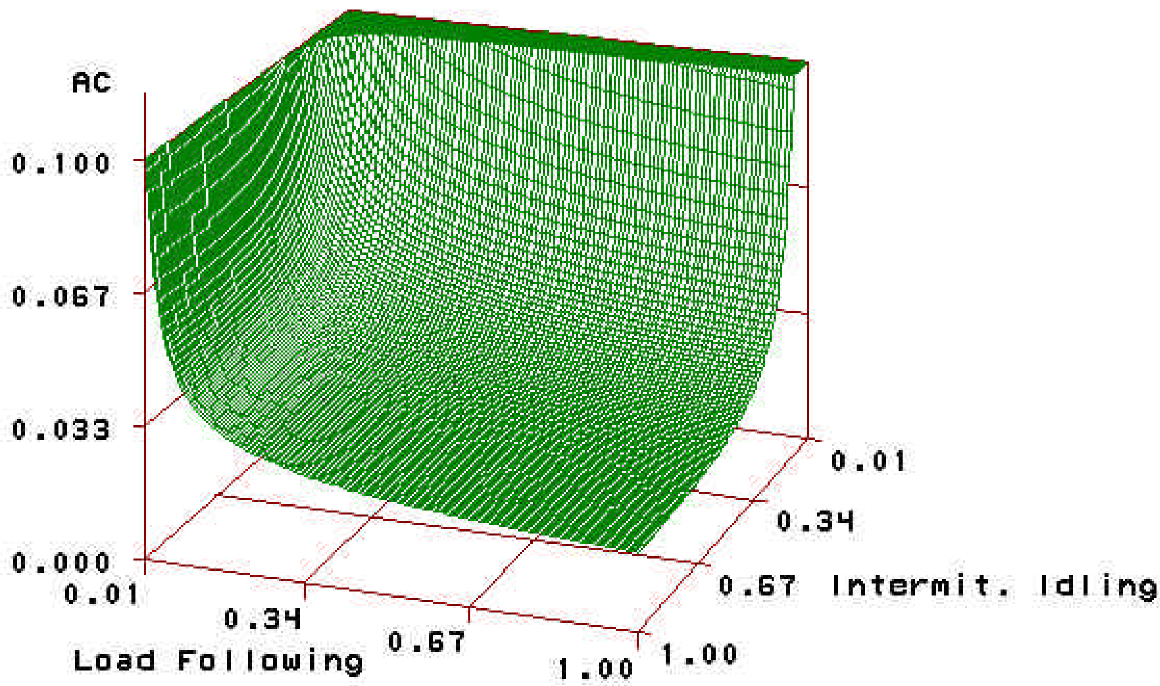


**Figure 2: AC for 100 MW Coal Plants**

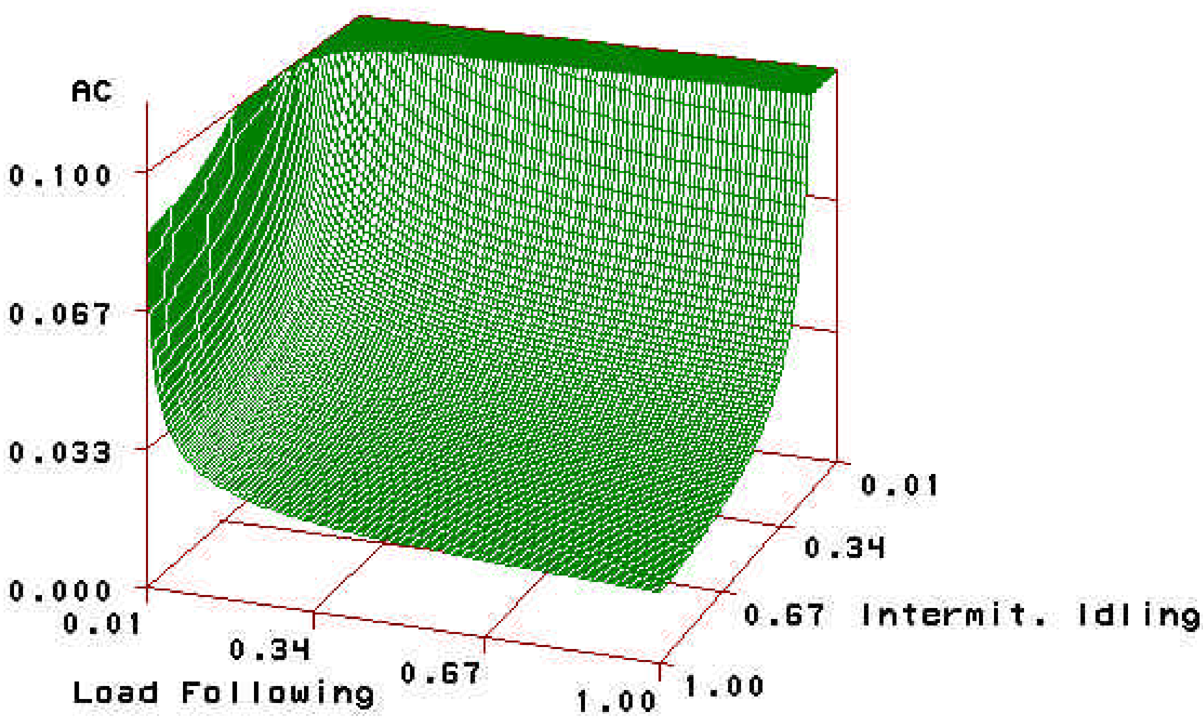


**Figure 3: AC for 800 MW Coal Plants**

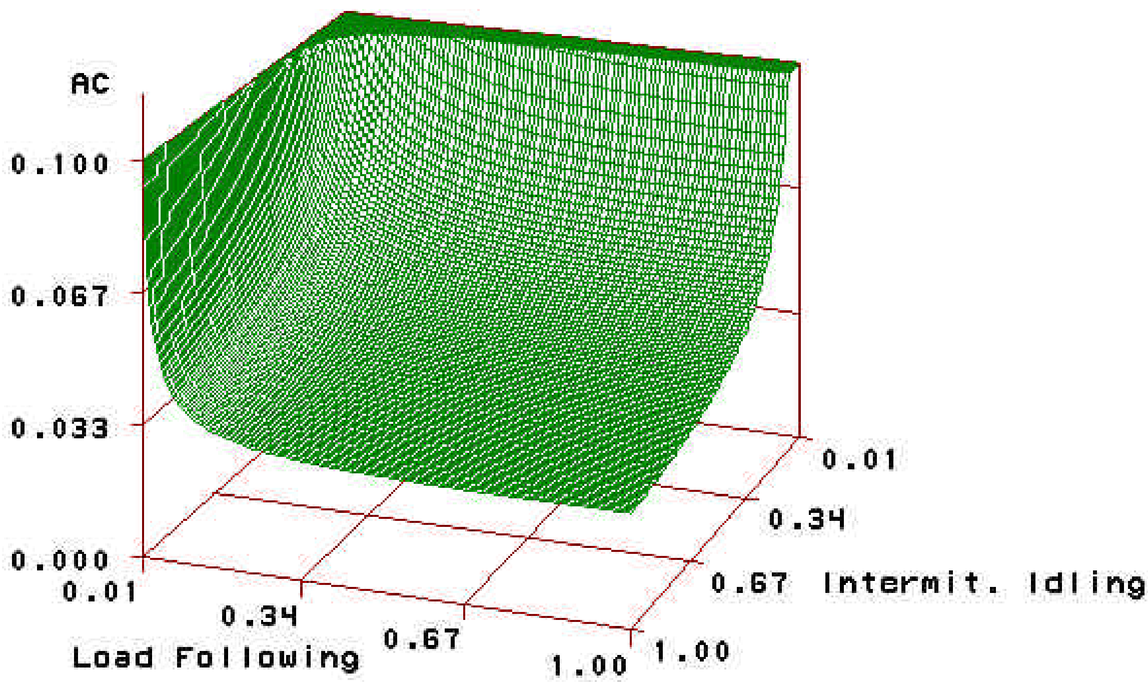


Figure 4: AC for 800 MW Gas & Oil Plants

**Table 5**
**Forecast Minimum Average Cost for Various Unit Sizes**

*Coal*

| Capacity | AC | Load Following | Intermittent Idling |
|---|---|---|---|
| 10 | $ 0.032 | 1.00 | 0.50 |
| 25 | 0.026 | 1.00 | 0.68 |
| 50 | 0.022 | 1.00 | 0.85 |
| 100 | 0.019 | 1.00 | 1.00 |
| 200 | 0.018 | 1.00 | 1.00 |
| 300 | 0.017 | 1.00 | 1.00 |
| 500 | 0.017 | 1.00 | 1.00 |
| 700 | 0.017 | 1.00 | 1.00 |
| 1000 | 0.017 | 1.00 | 1.00 |
| 1400 | 0.017 | 1.00 | 1.00 |

*Gas & Oil*

| Capacity | AC | Load Following | Intermittent Idling |
|---|---|---|---|
| 10 | $ 0.041 | 1.00 | 0.68 |
| 25 | 0.033 | 1.00 | 1.00 |
| 50 | 0.029 | 1.00 | 1.00 |
| 100 | 0.027 | 1.00 | 1.00 |
| 200 | 0.026 | 1.00 | 1.00 |
| 300 | 0.026 | 1.00 | 1.00 |
| 500 | 0.027 | 0.96 | 1.00 |
| 700 | 0.027 | 0.80 | 1.00 |
| 900 | 0.028 | 0.71 | 1.00 |

## V. Conclusions

The market price of electricity quoted in the *Wall Street Journal* has averaged around 2¢/kwh over the last year.[18] This number is a far cry from the historical cost of generation embedded in regulated prices. DOE reports the average regulated price to be over 4¢/kwh nation-wide. What can we expect market price to be as the competitive frontier is extended over a larger and larger portion of the industry?

The estimates presented here suggest that we can expect the current wholesale price of electricity to maintain. It is reasonable to expect that the lowest cost units are currently satisfying the competitive wholesale market and as competition grows, more inefficient units will become the margin of supply. However, the cost difference between units that run full time is not very large. Most of the difference in observed cost among power plants can be attributable to under utilization of capacity which will diminish with competitive pricing.

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[18] Electricity prices reported by the *Wall Street Journal* for energy delivered to the Palo Verde substation. The average is across peak and off-peak for firm power.