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SCALE ECONOMIES AND UNIT AVAILABILITY IN STEAM-ELECTRIC GENERATION: A NONHOMOGENEOUS CAPITAL APPROACH

by

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ABSTRACT

SCALE ECONOMIES AND UNIT AVAILABILITY IN STEAM-ELECTRIC GENERATION: A NONHOMOGENEOUS CAPITAL APPROACH

by

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This dissertation develops a model of electricity generating unit choice that explicitly recognizes the cost effects of declining unit availability with unit size. Unit availability tends to decline with size because forced outages and maintenance outages tend to increase with unit size. Ceteris paribus, declining unit availability causes expected output to grow at a slower rate than potential output.

To test the effects of declining unit availability on size, a theoretical model is first developed in such a way that expected unit output is determined by the generating units' instantaneous rate of utilization (unit size) and the expected availability rate of the unit.

Next, an engineering - economics cost function for fuel and capital costs was developed that allowed both the inference of scale (dis)economies and an examination of the engineering factors influencing these economic characteristics. In the model, capital was disaggregated

into dimensions of size and efficiency. Capital costs were determined by unit size, fuel efficiency, and other engineering design information. Expected fuel costs were determined by expected fuel prices, expected output, and fuel efficiency for the unit.

Combining fuel costs and estimated capital costs, the models objective was to estimate the cost minimizing level of unit fuel efficiency. Once estimated, the model was validated by comparing predicted heat rates and average costs to the observed values. As the model could not be solved to produce parametric tests of the extent of scale economies, the estimated model was used to simulate costs and efficiency for a variety of different geographical regions and exogenous engineering design circumstances.

The primary conclusion of the dissertation is that when one controls for the cost effects of unit availability minimum efficient unit size is on the order of 250 MW. Further, costs are shown to be insensitive to size once this MES is obtained.

This dissertation is dedicated to my grandfather, Earl E. Sexton.

ACKNOWLEDGEMENTS

In acknowledging those who have assisted me in producing this thesis the contributions of my dissertation committee are those that are most tangible. Professor Harry Trebing provided assistance both in developing the topic and in wading through the numerous rewrites. Professor Stephen Martin frequently accommodated his schedule for my questions throughout my graduate career. Professor Peter Schmidt's early advice on some of my econometric problems saved me from barking up several wrong trees. My chairman, Professor Kenneth Boyer, patiently guided me through the various stages that are required to produce good research. I could have undoubtedly saved several rewrites by paying closer attention to his advice at earlier stages in this process.

Less tangible, but no less important, are the contributions made by family and friends. The dissertation is only a culmination of a much larger educating process, and throughout this process I have benefitted immeasurably from the emotional and financial encouragement from my family.

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CHAPTER I: INTRODUCTION

In this dissertation we show that the unit level long-run average cost function for steam-electric generation is characterized by either diseconomies or by constant returns to scale beyond a relatively small capacity size. This result is in contrast to the conclusions reached by most previous researchers and it should be of interest for two primary reasons. First, our results derive from an inclusion of implicit costs that have been effectively ignored in previous scale studies – the implicit costs of declining capital reliability with size. Secondly, there are several pending policy issues whose resolution rest partially on the determination of minimum efficient generating unit size.[1] In this regard, a successful policy strategy will necessarily depend on a characterization of the technology that is complete with respect to all implicit costs of production. Below we consider these motivations in more detail.

Plant and unit level scale economies in the electric power industry have been extensively examined over the past 30 to 40 years.[2] A consensus emerging from this body of research is that the expected plant utilization intensity significantly contributes to the determination of plant level average costs or output. Since larger units tend to be utilized more intensively the lower average costs observed for these units partially reflects the lower average capacity costs associated with intensive utilization. But while these studies have been careful in allocating economies separately to unit size and utilization they have ignored the fact that larger units tend to be less reliable and require longer scheduled maintenance downtimes and are, hence, less available for producing output.

As far back as 1955 there existed fairly complete engineering literature discussions of the factors favoring and the factors against large electricity generating unit choices. Factors favoring large unit choices include declining per kilowatt capacity costs, lower operating and maintenance costs per kilowatt-hour, and increased fuel efficiency.[3] Factors disfavoring large unit choices include, *inter alia*, larger firm or system reserve requirements and declining unit availability. Larger unit choices necessitate larger reserve expenditures because when a large unit is unexpectedly forced out or derated a more severe strain is put on the system in servicing demand. Another way of saying this is that the expected value of the output of a larger unit is less than the expected value of two half-sized units, even when the availability of the units is the same. To guard against the likelihood that the firm will not be able to meet a given load the firm must keep more reserves on hand when larger units are chosen.[4]

Declining unit availability with size results from two factors. First, larger units are typically designed for higher pressures and temperatures and tighter turbine tolerances. In the past these characteristics have led to higher forced outage rates for larger units as compared to smaller ones. Second, maintenance durations for larger units are longer because larger pieces of equipment must be disassembled, inspected, and replaced.

For the most part, each of these factors continues to be important today. The engineering literature includes all of these concerns in current plant and firm models. But while the economic literature has recently begun discussing the factors disfavoring large unit choices it is surprising that there are no unit or plant level cost or production function studies which fully recognize these problems.

In addition to the model specification problems noted above, however, there are also overriding policy interests which motivate our analysis. The issue of scale economies is becoming increasingly important in electricity generating markets. That the typical electric utility usually employs a number of generating units suggests that the generation market may not be characterized by natural monopoly. And there have been several recent suggestions to deregulate this industry by vertically dismembering generation assets.[5] If firm level multiplant or multiunit generation economies are appropriable through other institutional mechanisms[6] then unit and plant level economies would become the controlling factor in determining effective competition in bulk power markets. And baseload plant reliability stands out as an important influence in determining these economies.

Additionally, even in the current regulated environment there should be interest in the cost effects of unit reliability. Commissions are at least indirectly responsible for encouraging unit and plant choices that complement the firm. If expected unit reliability and scheduled maintenance significantly affects costs, uninformed decisions will result when not taking availability into account.

When investigating scale economies it is the relationship between scale and availability that is important. As we have noted above, the relationship between these two is inverse. Statistics on equipment availability which have been published regularly by the Edison Electric Institute since the late 1950's have all indicated declining unit availability with size. Table I.1 illustrates this relationship with availability rates, equipment forced outage rates, and scheduled outage rates by unit size.

TABLE I.1

Availability Rates by Unit Size[7]

k	Equivalent Availability	Equivalent Forced Out Rate	Schedule[8] Out Rate
100 - 199MW	.852	.059	.094
200 - 299MW	.827	.080	.096
300 - 399MW	.758	.122	.131
400 - 599MW	.745	.132	.139
600 - 799MW	.679	.199	.149
800 - Above	.675	.228	.124

Since it seems plausible that managers are capable of forming expectations about unit availability and since availability would seem to affect the unit choice decision our instant problem is to explore how availability affects costs.[9]

Standard empirical results show that increases in unit size, <u>ceteris paribus</u>, lead to reductions in per kW costs.[10] Holding constant availability rates, then, average capacity costs should decline with output.

In varying degrees, however, declining availability with size has the opposite affect on average costs. The cost effects of availability are most serious in baseload units. As baseload units are, by definition, economically preferred on a round-the-clock basis, the lack of availability over any period translates directly to the cost penalty associated with operating units with higher short-run marginal cost. For non-baseload units, which may be designed to cycle with daily and seasonal loads, increasing forced outages would continue to increase expected average capacity costs, but planned outages may be scheduled for periods when the unit is idle. Since many of the anticipated outages do not affect the expected output of the unit, availability rates are less important in determining costs.

Couched in other terms, the concern motivating an analysis of availability rate effects is utilization intensity. It is clear that one may produce the same output with a larger unit at low utilization or a smaller unit at relatively higher utilization. And indeed one can find ex post utilization intensities as low as 10-20 percent for high marginal cost peaking or cycling units. But in addition to the variability of utilization intensity there also tends to be a postive relationship between unit size and utilization. Larger units are more likely to be baseload or near baseload units with large utilization intensities relative to the smaller utilization rates expected for smaller peaking units. Consequently, ignoring utilization in unit or plant cost studies would seriously bias the cost effects of increasing unit size.

One way that several authors have of controlled for differences in utilization is to introduce the ex post plant factor directly into the cost or production function.[11] A robust result of these models employing the plant factor is that scale economies due to size are much smaller, if they exist, and "economies" due to increased utilization are much more important. But while these authors have made important contributions to understanding plant and unit level cost functions there are problems with using plant factor as a proxy for _ex ante_ utilization intensity.

Expected utilization intensity, or plant factor, can be broken into two components: desired utilization and expected availability. Expected availability has been discussed above but we should take a closer look at desired utilization.

For well known reasons, electricity production is distinct from processes which produce physical outputs. Firms are required to serve a peaky load schedule with an output which is economically non-storable. As a result of these demand and technology constraints, firms rationally choose some plants for which the desired utilization intensity is relatively small in trying to meet the firm's total annual load at the smallest cost. These are typically small, low capital cost-high fuel cost, peaking plants. At the other extreme are the higher capital cost-lower fuel cost plants designed to run continuously throughout the period. The intended utilization for these plants is one. Between these two extremes are cycling plants designed to run for intermediate lengths of time.

The question now arises as to what the effect is of mixing baseload and non-baseload units in a sample and controlling for _ex post_ utilization but not desired utilization. A first problem here is that there may be units with the same size and _ex post_ plant factor having different costs because of different desired utilization levels. Non-baseload units are designed with less efficiency because there is less incentive _ex ante_ to substitute fuel efficiency related capital for fuel when designing a unit if the desired utilization of the capacity over the period is small. Non-baseload units are designed with reduced turbine tolerances and lower steam and temperature conditions.[12] And this translates to a substitution of fuel for efficiency related capital relative to the design characteristics of baseload units.

But in addition to the differences in unit design for baseload and non-baseload of the same size, declining availability should more seriously affect baseload units as size grows. For non-baseload units, increasing planned outages with size may, depending on the level of desired utilization, be scheduled for periods when the unit is not needed. If increasing planned outages can be placed entirely during periods during which the unit is not desired then these planned outages will have no effect on _ex ante_ output of the unit. For baseload units, however, every increase in either expected scheduled outage or expected forced outage directly inhibits *ex ante* output for the plant.

There is little that we can say here with respect to the effects on average costs for different levels of desired utilization. *Ceteris paribus*, declining unit availability should lead to increasing average capacity costs for baseload units. The higher efficiencies associated with increasing unit size, on the other hand, should lead to declining average fuel costs for these units. For non-baseload units declining unit availability should have a relatively smaller impact on *ex ante* average capacity costs because, again, *ex ante* output for these units should be less affected by declining availability. But while the effects on average cost of different levels of desired utilization is unclear it is apparent that both desired utilization and availability combine to determine scale economies.

Our study proceeds as follows. A review and critique of existing studies will be provided in Chapter II. In Chapter III we begin by developing the theoretical structure of our model. The approach developed to measure scale economies is nontraditional to a degree. The traditional neoclassical cost minimizing view of production is expanded to envelope specific engineering characteristics of capital. The result is a model that describes the electric power generating technology in terms of both its physical and economic attributes.

Total plant costs in the model will be comprised of annual capital costs and annual running costs. Chapter III continues from a theoretical development of the model to estimation and presentation of the plant cost function that will be used to determine the capital cost component of total plant costs. The plant cost function will be presumed to represent a generating unit manufacturer's schedule of investment costs for different plant characteristics. Chapter III will conclude with estimates of this plant cost schedule.

Chapter IV begins with a discussion of how we use the model developed in Chapter III to determine the minimum average cost for plants in our sample. After discussing the solution to the model we then provide evidence that our model predicts observed average costs reasonably well. To take the next step in attempting to infer the extent of scale economies our modelling construct requires that we use the model to simulate cost minimizing efficiency levels and associated average costs for different plant sizes and relative factor prices. The presentation of the results of this simulation exercise will conclude Chapter IV.

Finally, a summary of our study will be provided in Chapter V.

CHAPTER I: ENDNOTES

1

We use the terms unit and plant interchangeably throughout. A generating plant is made up of one or more boiler-turbine-generator (BTG) units. While the focus of this analysis is on unit level scale economies the analysis that follows does allow for multi-unit economies to account for those instances when multiple units are included in a single plant.

2

Nordin (1947), Barzel (1964), Dhrymes and Kurz (1964), Cowing (1974), Huettner (1974), Fuss (1978), and Stewart (1979) are some of the more frequently cited studies in the literature. For an excellent survey of econometric studies of this industry see T. Cowing, and V. Kerry Smith, "The Estimation of a Production Technology: A Survey of Econometric Analyses of Steam-Electric Generation, Land Economics, 54, 2, May, 1978.

3

L. Kirchmayer, A. Mellor, J. O'Mara, and J. Stevenson, "An Investigation of the Economic Size of Steam-Electric Generating Units," Transactions, American Institute of Electrical Engineers, August 1955, 600-609.

4

There are two independent reasons why larger unit choices cause larger reserve requirements. First, larger unit choices imply larger average unit size for the firm. Holding availability rates constant, larger average unit sizes imply the need for larger reserves (imagine the reserve requirement if the firm sought to service all demand withe a single unit). The second effect is then the declining availability with unit size. For a more complete discussion see Galabrese (1947). Also, a good theoretical discussion of these effects is found in Burness,et al. (1985).

5

A sampling of this literature would include Berry (1982), Golub, et. al., (1983), and Huettner and Landon (1976).

6

A possible mechanism would be the bulk power broker considered in Huettner and Landon (1976).

7

Edison Electric Utility Institute, Equipment Availability for the Ten-Year Period: 1967-1976. EEI no. 77-

64,New York, 1977. All references made to availability in the text refer to equivalent availability. Equivalent availability is a measure of unit availability that accounts for partial as well as full outages. For a complete discussion of the availability information used in the analysis the reader should refer to Appendix A.

8
Also given in the Edison Electric data are the major causes of forced outages. The primary cause of forced outages is boiler problems. For the 100-199MW group the forced outage rate for the boiler alone 2.9 percent and the forced outage rate for the turbine alone was .9 percent. For the 800MW and larger group the forced outage rate for the boiler was 10.8 percent and the forced outage rate for the turbine was 3.5 percent. Remaining outages were attributable to the condenser, the generator, and other equipment.

9
The formation of availability expectations based on the EEI data may seem simplistic. However, in my discussions with Mr. David Bedford, Vice-President of Operations with the Public Service Company of New Mexico, he indicated that these were the statistics they used in their in-house models.

10
See for instance Huettner (1974), Cowing (1974), and Stewart (1979). The reason for this is commonly attributed to the "six-tenths" rule. As the volume of a sphere grows its' surface area increases by approximately "six-tenth" of that increase. Since capacity is more nearly related to "volume" and costs are more nearly related to the surface area, per kW plant costs should decline with capacity This is more fully developed in Chapter III.

11
Plant factor is defined as the ratio of actual output to potential output at rated capacity over some period.

12
Improving the efficiency of a particular unit essentially involves improving the temperature and pressure conditions of the steam cycle. Primarily, this involves the addition of reheat stages or feedwater heaters. Both involve bleeding off steam from an intermediate turbine blade. In the reheat stage the bled steam is simply reheated and reintroduced at the next turbine blade. The feedwater heater, however, takes the steam and reintroduces it to the boiler. Since both enhance steam enthalpy the cycle efficiency is improved. See Roth (1970, pp. 48-58) for a moderately technical discussion of the steam cycle.

CHAPTER II

MODELING THE STEAM-ELECTRIC GENERATION PROCESS: REVIEW

Below we critically evaluate studies that have investigated unit or plant level electricity generation scale economies. Due to the capital intensity of this industry, and to the consequent large amount of good data on this industry, electricity generation studies have become a nesting place for new developments in cost and production theory. Consequently, there is a large number of studies to review. But, in addition to the large number of studies there are also many different methodologies. There are a number of ways one might stratify these studies. We have divided these studies into two groups: those which have employed an assumption of firm level optimization and those which have not. The former group includes a variety of cost, production, and profit function studies. The latter group is something of a catch-all group including simple cost-output relationship as well as some studies from the engineering and engineering-economics literature.

With respect to this separation of studies we should keep in mind that the definition of economies of scale is a narrow and precise one. Economies of scale occur for any output region wherein long-run average costs decline with output.[1] A prior assumption embedded in the long-run average cost curve is that all factors are employed in a least cost manner in producing each output quantity. Consequently, any study which attempts to measure economies of scale without adhering to a firm level cost minimizing principle is technically invalid.

What we have said, however, should not be taken to mean that studies which do not relate to cost minimizing principles are without merit. All of the studies have contributed to the body of knowledge concerning the economic description of this technology. Moreover, many of the hypotheses which have found their way into cost minimizing analyses evolved from some of the less formal cost studies. We take up first the group of firm optimizing models.

2.1 MODELS WHICH ASSUME FIRM LEVEL OPTIMIZATION

Yoram Barzel provides a careful study of the steam-power plant production function and changes in industry technology.[2] He is also one of the first to acknowledge the misspecification that occurs when one ignores plant utilization intensity.[3] He notes, "The distribution of output over time in the steam power industry is not entirely up to the firm. Consequently, output is a function not only of the size of the plant but also of the extent to which this plant is utilized."[4]

The first methodological problem Barzel takes up is dismissing the production function empirical approach. Here he argues that since a production function approach would require including the plant factor and plant size on the RHS, and since output is identically related to plant size and utilization intensity, "...the production function leads to an identity relation between the dependent and independent variables in the production function."[5]

The alternative taken then is the input demand function approach. Here, Barzel develops three input demand functions for fuel, labor, and capital. Since most of our concerns appear in his fuel and capital equations we take them up explicitly.

With a sample of plants which were newly constructed between 1941 and 1959 Barzel estimates the following fuel demand function.

$$\log Y_f = \Sigma b_i \log x_i \qquad (I.1)$$

Where,

Y_f = fuel input (Btu/year),

x_1 = plant size (kw),

x_2 = anticipated average load of plant, measured by the observed load factor in the first full year of operation,

x_3 = within-plant index of x_2, over time

x_{4-19} = fuel price and vintage variables.

The inclusion of x_3 in the equation is Barzel's way of attempting to capture a short run scale effect in addition to the long-run scale effect which x_1 and x_2 combine to pick up. The within plant index of x_2, x_3, is merely an index of the actual load factor in later years divided by the expected plant factor, x_2. Since the variable x_3 is presumed to be the expected load factor it reflects the *ex ante* scale effect for utilization. But since short-run load factors may vary from the expected load factor and hence affect fuel costs in later years, x_3 picks up this short-run utilization effect.

Since our concerns here are entirely with *ex ante* scale effects we concentrate our attention on the variable x_2. Certainly the inclusion of both x_2 and x_3 removes some of the bias on the size variable. But the arguments we have made throughout apply here as well. Since x_2 captures information on both desired utilization and expected availability, b_2 may be biased. Implicit in the approach is an assumption that either the availability rate or desired utilization is the same for all plants. If it is the former, which seems more likely, then b_2 will be biased to the extent baseload and peaking plants are mixed in the sample.

Barzel's capital input demand equation is:

$$\log P_k = \sum_{i=1}^{4} b_i \log x_i + \sum_{i=5}^{18} b_i x_i . \qquad \text{(II.2)}$$

Where,

P_k = total undeflated value of plant,

X_1 = capacity size,

X_2 = labor price,

X_3 = fuel price,

X_4 = load factor,

X_{5-18} = vintage dummies.

In the capital input demand equations Barzel uses the "total undeflated value of plant" for the dependent variable. Arguing that different generators of the same size may embody different equipment he rejects capacity as a measure of the "quantity" of capital. And dismissing the validity of price indexes because of their broad coverage he eliminates all "quantity" measures excepting that chosen.

A distinguishing feature of the analysis is Barzel's inclusion of the load factor in the capital equation. Barzel explains the inclusion of this variable by saying that, "The higher the load factor at which a plant is expected to operate, the more desirable it becomes to obtain equipment that can cope with the heavier strain, and consequently the higher the cost of equipment."[6] This is the same point that we made in Chapter I above. The coefficient on the load factor term is both positive and significant at the 99 percent level but, unfortunately, Barzel must use the *ex post* plant factor as a proxy for what he is attempting to capture. As we have noted, the desired utilization rate is the appropriate determinant for plant costs, and, because of declining availability, the <u>ex post</u> plant factor may nonsystematically understate desired utilization.

Dhrymes and Kurz[7] developed input demand functions for fuel, capital, and labor from a limited - substitution generalization of a CES production function:

$$Q = \min [g(L), (\alpha_f F^{\beta f} + \alpha_k K^{\beta k})^{1/\mu}]. \qquad (II.3)$$

In (II.3) a minimum of g(L) is required to produce Q. It is obvious that the firm may not optimize with respect to labor in this production function. Fuel and capital, however, are substitutable in an <u>ex ante</u> sense.

Since it was not possible to develop the three demand functions explicitly in terms of output and price ratios a two-stage technique was used to derive the nonstochastic portion of K, K^*. A linear Taylor series was used to derive the nonstochastic portion of K.

$$\ln K^* = a_0 + \Sigma_{i=1} a_i \ln \pi_i + a_k \ln Q^* \quad (i=k) \qquad (II.4)$$

Where,

$$\pi_i = p_i / p_k .$$

Since Q is presumed exogenous this expansion is approximate.

Next, the input demand functions were estimated over 362 plants which began operation over the period 1937-1959 and for 13 vintage-capacity size cells. The five size categories were 0-40 MW, 41-120 MW, 121-200MW, 201-449MW, and 450MW and larger. The four vintage groups were 1937-45, 1946-50, 1951-54, and 1955-59.[8]

Scale economies were found in each of the cells with the rate of returns to scale falling with size in all but the smallest size groups.[9]

The Dhrymes and Kurz methodology appears sound. However, we have two concerns with underlying assumptions in the model. Our first concern is with the construction of the service price of capital. In deriving the service price of capital the authors first derive the plant level price of electricity with what is referred to as a "residual method".[10] First, let

$$\pi = TR_F - TC_F .$$

The subscript, F, indicates the firm level and total costs, TC, are defined such that π measures the return to total capital of the firm. Next, we let α = equity/asset (Book) ratio. Then, $\pi\alpha$ represents return to stockholder capital for the firm. Now if this value is divided by net generation at the firm level one gets a measure of the firm generation level price of electricity.

To derive their service price (cost) of plant capital one first multiplies the electricity price calculated above by net plant generation, giving the return to stockholder capital at the plant level. Subtracting plant operating expenses and dividing by net plant output one then gets P_k, the capital rental price (cost) per megawatt hour.

Our primary concern with the measurement of P_k here is that using firm level data in the calculation of the electricity price assigns the same price of electricity to all plants in the firm. This is noted by the authors, "Note that this method has the consequence of assigning the same price to all plants of a multi-plant firm."[11] This seems implausible and would seem to deny that these electricity prices calculated on a plant basis would no doubt reveal higher electricity prices for non-baseload units than for baseload units. And, by extension, this bias would affect P_k.

Our second concern is that there is no accounting for different utilization levels in the analysis. That scale economies with output are discovered is unsurprising since larger output levels will be correlated with larger plants and larger _ex post_ utilization intensities. But since many of the plants are likely to be intended for different utilization it is unlikely that they all belong on the same long-run cost function.

The principal concern of Roth[12] is the separation of technology and scale effects. In contrast to other studies, which employ a vintage proxy, or cost or production function estimation for different time periods, Roth isolates technologically homogeneous populations of plants and investigates scale effects within these populations. Seven technologically homogeneous populations are established considering furnace type, number of bleedpoints, number of reheat cycles, pressure-temperature, and generator cooling type.

Input demand functions are derived from a profit function which includes varying forms of the CES and Cobb-Douglas production functions. One must question, however, whether or not it is appropriate to derive plant level input demand functions from a firm level profit function. Viewing the problem from a cost function perspective, it is not necessarily the case that firms seek to minimize unconditional plant level cost for a given output. Rather, firms seek to minimize plant level costs conditioned on whether the output level is incurred at peak load or baseload, or somewhere in between. If baseload and non-baseload plants are mixed (and they are), then the firm level profit function is not appropriate for deriving input demand functions for the plant.

That Roth includes baseload and non-baseload plants in his sample is revealed above. But in addition, there is no control for plant factor or different levels of utilization. He notes, "A smaller proportion of the variation in capital input was explained by output and the number of machines, presumably because differences in plant factors across plants account for some variation in the installed capacity required to generate a given annual output with a given number of units."[13] That plant factor may vary systematically with unit size is not considered. And, given this 'missing variable', it is not surprising that Roth finds that "increasing returns to scale is characteristic of steam-electric generation at the plant level."[14]

Thomas G. Cowing[15] provides one of the early examples of how one might characterize the steam-electric technology with an engineering process approach. As contrasted with the more general neoclassical characterization of technology the engineering process approach blends technical information - or specific engineering variables - with the traditional economic variables in describing a particular technology.[16] In this he estimates input demand functions for the two presumed characteristics of capital: size and efficiency. The reduced form equations that were estimated are given below.

$$\ln E^{*}(p,v) = B_1 + a \ln p + bv \qquad \text{(II.5)}$$

$$\ln Z^{*}(p,v) = B_2 + c \ln p + dv$$

E^{*} = design efficiency for unit (Btu/kwh),

Z^{*} = unit size,

p = ratio of present value fuel price to price of capital,

v = vintage index.

In the model, E and Z, (that is, observed unit design efficiency and size) are presumed to be respective first order solutions to a capital and fuel cost function. With capital costs being determined in an hedonic machinery cost function and fuel costs being determined by unit efficiency and the plant factor, this function is written as

$$PV_m = zG(z,e,v)p_k + zP_f/E. \qquad \text{(II.6)}$$

Where,

$$P_f = \int_0^T p_f(t)l(t)e^{-rt}dt$$

p_f = expected fuel price in period t, and

$l(t)$ = expected plant factor.

Here, G is the hedonic average plant cost per unit of capacity, z. And P_f is "...a kind of expected present value price of fuel."[17]

That Cowing finds significant scale economies is related to the way in which utilization, l(t), enters his model.[18] Rather than exploring an independent scale effect for utilization the utilization effect is embedded in the price ratio on the RHS of (II.5). Thus the *ex ante* scale effect would seem to be a reflection of both unit size and utilization effects.

As is the case with all of the studies we have reviewed, Cowing does not control for variations in intended utilization or expected availability rates. But there is one more potential problem which we should make note of. The observation used for E^*, the unit heat rate, was the published design heat rate for the unit. In our own sample we found that for 24 plants which had published design heat rates the mean design heat rate was 8955.6, while the mean *ex post* heat rate for these same plants was 10358.6.[19] Moreover, only one plant in our sample had an *ex post* heat rate which was less than the design heat rate. We do not have access to his data, but these figures would suggest that the design heat rate may be a poor proxy for the expected heat rate.

Cowing's engineering process approach is appealing because it provides a fuller description of the steam-electric technology at no expense to the optimizing spirit of the neoclassical approach. However, the problem of identifying the separate cost effects of availability and desired utilization remains.

The only example of a plant level scale analysis which uses a translog cost function is provided by Fuss.[20] Fuss specifies expected *ex post* costs with a generalization of the Diewert cost function.

$$EC_t^v(p_{1t}^v,\dots,p_{nt}^v,Ey_t^v) = \sum_{i=1}^{n} b_{ii}\, p_{it}^v\, h_i(Ey_t^v) \qquad \text{(II.7)}$$

$$+ \sum_{i=j}\sum b_{ij}\,(p_{it}^v\, p_{jt}^v)^{1/2}\, h(Ey_t^v) \qquad i,j = 1,\dots,n$$

Where,

p_{it}^v = expectation of the price of the ith factor formed at time v.

What distinguishes this formulation from the usual Diewert cost function is the substitution of $h_i(Ey_t^v)$ and $h(Ey_t^v)$ for the typical output variable. These two terms are defined as

$$h_i(y_t^v) = (l_t)^{\beta i}\, Y_t^v = (y_t^v/Y_t^v)^{\beta i}\, Y_t^v, \qquad \text{(II.8)}$$

and

$$h(y_t^v) = (l_t)^{\beta}\, Y_t^v, \text{ respectively.}$$

Where,

l_t = plant factor (actual output/potential output),

Y_t^v = designed output at time t,

y_t^v = actual output at time t, and

β, β_i = parameters to be estimated.

Apparently Fuss is attempting here to fold into the expected output variable an accounting for unintended utilization. In defining the potential output for the plant, EY_t, however, Fuss states, "The expected yearly output at time t, EY_t, is assumed to be equal to the rated capacity (on a yearly basis) times the expected proportion of the year the turbine-generator is hot and connected to load."[21,22] This has the effect of overstating the actual utilization intensity on an annual basis. With this adjustment a small peak load plant and a large baseload plant may well have the same utilization intensity. The majority of scale effects are therefore forced back into the single dimension of capacity effects.

Fuss goes on to estimate *ex post* and *ex ante* input demand functions for the four factors: structures, equipment, fuel and labor. But since his primary interest is in testing the putty-clay hypothesis, scale effects are lumped in with vintage effects and no attempt is made to sort them out.[23] Nevertheless, from a strict neoclassical cost function standpoint the approach is sound and would be appealing if utilization economies were handled better or if there was an attempt to limit the study to baseload units.

Stewart extends the class of cost function studies which take explicit account of engineering variables. The first problem he takes up is the development of an appropriate output notion. Given a non-uniform load curve and non-storable output Stewart imagines a system planner who selects a plant for a specific increment of the load curve. In this, the plant choice reflects an instantaneous rate of power, K, and the duration of operation over the period. The load increment for the plant being defined,

expected cumulative output for the plant is given as

$$Q = 8760bK.$$

Where,

8760 = hours in year

b = expected plant factor, and

K = capacity (kW).

Next, Stewart follows Cowing by defining capital in dimensions of efficiency (BTU/kWh) and size. The problem for the planner is then to take a known load increment which is defined by K and b, and choose a cost minimizing efficiency level for the unit. For known load increment and expected relative factor prices the cost minimizing heat rate, is given as

$$\alpha^* = g(K,b,P_f,r). \qquad \text{(II.9)}$$

Where,

α^* = cost minimizing heat rate (BTU/kWh)

P_f = fuel price, and [25]

r = cost of capital.

Given the cost minimizing heat rate Stewart writes the <u>ex ante</u> fuel and capital cost function as

$$TC^*(K,b,P_f,r)=g(K,b,P_f,r)8760bKP_f + rP_k(g(K,b,P_f,r),K)K. \qquad \text{(II.10)}$$

Where,

$P_k(.)$ = the per kW cost of capacity.

Here we should note that while decreases in the heat rate (increases in efficiency) reduce <u>ex ante</u> fuel expenditures they come at the expense of increasing plant cost expenditures which make the increase in efficiency possible. This results in a neoclassical condition where a unique cost minimizing heat rate obtains.

The cost of plant function is estimated for a cross section of 58 gas turbine and steam-electric units which began operation during the 1970-1971 period. Using a log-log specification Stewart finds per kilowatt plant costs declining at a decreasing rate with declining efficiency, as expected.

Given the cost of plant estimates, the load increments and expected factor prices, Stewart then solves numerically for the cost minimizing heat rate, α^*, and the associated minimum average costs.[26]

Confirming the reasonableness of the model by comparing predicted heat rates and average costs with actual values he then uses the model to simulate average costs for a grid of sizes and plant factors. Surprisingly, an important finding here is that there are diseconomies of scale due to size for all steam-electric plants and for each plant factor. However, Stewart points out that the diseconomies indicated result largely from the positive coefficient on size in the plant cost function.[27] Since the partial with respect to size is not significantly different from zero little faith can be placed on the diseconomies indicated.

Stewart's conclusions read, in part, "The major source of cost reduction at the unit level comes from increases in the plant utilization factor, not from increases in the size of the unit, and the cause of declining average cost is primarily a result of the ability of plants with higher utilization rates to spread capital expenses over a greater volume of output. That econometric studies have consistently found average cost declining with cumulative output is not surprising, given that larger plants are generally operated at higher plant factors.[28]

As with previous studies, Stewart presumes that the plant factor observed in 1972, the year after plant installation, is the *ex ante* utilization rate. We know that the intended utilization rate is greater than or equal to this *ex post* plant factor. But we do not know by how much when no attempt is made to exclude non-baseload plants. That is, by mixing non-baseload and baseload plants together in the same sample the utilization effect seems to be picking up the effect of becoming a baseload plant rather than what is traditionally thought of as a 'scale' effect. And the question arises as to whether gas turbine peaking power and steam-electric baseload power are the same product.

As in Cowing (1974), the engineering variables used in the cost function complement the information normally obtained from only relative factor price and output. Unfortunately, however, Stewart's mixing of gas turbine peaking plants with plants intended for larger utilization intensities leaves his results open to criticism. Nowhere are the differences in desired utilization more pronounced than they are across this sample. And failure to control for these differences merges the scale effects of baseload units with those of peaking units.

2.2 MODELS WHICH DO NOT ASSUME FIRM LEVEL OPTIMIZATION

Lomax provides the earliest example of a study which does not explicitly assume firm level optimization.[29] He also appears to be the first author to acknowledge the importance of plant utilization in determining plant level average costs. He argues, "It is most important in investigating the laws of true returns to scale for electricity generation to be able to allow for varying load factor because there is a natural tendency in big undertakings with large numbers of consumers for irregularities in demand to be smoothed out to some extent and the load factor improved."[30] Accordingly, Lomax estimated the following regression for all steam-electric power stations in England which were operated for 6600 hours or greater during 1947.

$$\text{North-West} \quad \ln Y = C_1 - .12 \ln X_1 - .41 \ln X_2 \qquad \text{(II.10)}$$

$$\text{South-East} \quad \ln Y = C_2 - .15 \ln X_1 - .70 \ln X_2$$

Where,

Y = costs per unit generated, in pence

X_1 = capacity of generator (kW)

X_2 = load factor, and

C_i = constant term.[31]

That Lomax failed to use some kind of input demand approach is perhaps related to the fact that the article was published in the year preceding Shephards' seminal book presenting the duality between cost and production functions.[32] It is interesting, though, that even at this early writing Lomax seems keenly aware of the fact that larger plants tend to be baseload and hence used more intensively. One sees these concerns when he notes, "It should be pointed out, furthermore, that the two independent variables being highly correlated it is very difficult, statistically, to separate out their effects."[33]

Lomax's results are consistent with other researchers who find relatively more important 'economies' in utilization. He notes, "This rate of decrease in costs as size increases for unchanged load factor is probably less than would be generally expected. The big undertakings in this country have the high load factors and long hours of generation so that actual costs in large stations are appreciably lower than size alone would imply.[34] This statement is consistent with our observation that scale economies should be investigated for only a class of plants which has the same intended plant factor.

Kirchmayer, et al. is discussed here as only one example of the numerous engineering cost studies which investigate plant size choices with plant and system cost simulations.[35,36] It is not a statistical study and therefore not suitable for any testing of scale hypotheses. Our review of the article is justified, however, because of the explicit consideration of the engineering suboptimizations implicit in the production function or cost function approach.

Kirchmayer's method was to assume an existing 2000MW system and investigate costs when the system is expanded to a size of 10,000MW for different plant size choices. A host of unit level and firm level considerations were considered: "Factors such as the size of the system, forced outage rate, rate of load growth, installed cost of larger generating units, the effect of a maintenance program, and the effect on the transmission system of the use of larger generating units have been taken into account."[37]

While the results of the analysis are certainly conditioned on cost considerations specific to their time frame their conclusions read, in part, as follows.

1. If the investment cost of large units continues to decrease with size and the forced outage rate for large units remains at the present level [2 per cent (%) or lower], the most economical pattern of system expansion is to add units of between 10% and 7% of the size of the system studied.

2. If above any size the investment cost in dollars per kw remains constant, there will be very little incentive to use units above this size.

3. Any increase in the forced outage rate of large units will slow up the move to these large units.

It is their third conclusion above that partially motivates our analysis.

Komyia sought to determine declining input requirements in generation over the 18 year period 1938 to 1956.[38] Tentatively he acknowledged three possible sources for the decline in input requirements: scale economies, technological growth, and factor substitution. After dismissing the Cobb-Douglas production function for poor performance he retreated to a Leontief framework investigating production function shifts and scale economies. His device for sorting out these effects was a set of three input requirement functions given below.

$$Y_f = a_f + b_{f1} x_1 \quad (1) \qquad \text{(II.12)}$$

$$Y_c = a_c + b_{c1} x_1 + b_{n1} x_2 \quad (2)$$

$$Y_l = a_l + b_{l1} x_1 + b_{n1} x_2 \quad (3)$$

Where,

Y_f = fuel input per generating unit when operated at full capacity,

Y_c = log of equipment cost per unit,

Y_1 = log of average number of employees during year per generating cost,

X_1 = log average size of generating unit, and

X_2 = log of number of units in the plant.

A sample of 235 plants which were newly constructed in the period were further subdivided into four vintage cells, and also by coal and non-coal types. The vintage groups were 1938-45, 1946-50, 1951-53, and 1954-56. A general finding was that there were significant reductions in input requirements with scale across the vintage groups. Additionally, he found a significant reduction in input requirements in the post-war vintage groups as compared to pre-war plants, holding scale constant.

His adjustment of fuel input to full capacity utilization was unfortunate, however.[39] For when he makes this assumption he discards the possibility of investigating utilization intensity effects. And no attempt is made to use a proxy for ex ante utilization. While there is some evidence that forced outages were much less of a problem for the period considered it is unlikely that all 235 plants were intended for full utilization.[40]

A final concern we have with Komyia's analysis is that it seems premature to reject substitution possibilities because of poor performance from the Cobb-Douglas functional form. The unexpected parameter signs and the general lack of statistical significance could have resulted from a simultaneous equations problem or from the restrictive substitution elasticities imposed by the Cobb-Douglas functional form. And there existed several references to the substitution possibilities of efficiency related capital for fuel in the engineering literature.[41]

Another engineering analytic investigation of electricity scale economies is developed by Ling.[42] Ling's objective is to use an analytic-engineering model to simulate costs for some typical electric utility. He begins with a base system size of 2500MW made up of ten 5MW units, twelve 100MW units, and four 200MW units. Then the following assumptions are imposed.

1. Investment, operating and maintenance costs are as in Kirchmayer et. al.

2. Fuel cost is 25 cents per MBtu.

3. System peak load is 1950 MW.

4. Maintenance outage is equal to 20 weekdays and unit forced outage rate is equal to 2 percent.

5. Fixed charge on investment is equal to 12 percent.

The assumption of a constant outage rate for all unit sizes, which departs from our analysis, may have been appropriate for the technological vintage Ling works with. And he provides a discussion of why the assumption is plausible for his analysis.[43]

Ling then goes on to allow the system to expand along the same expansion path as in Kirchmayer. Provided, however, is relatively more sophisticated analysis of costs.

Station heat rates were determined by pressure, temperature and unit size. And individual plant factors are "chosen" under a developed merit loading model.[44] With this information a system-wide total cost function is developed as a function of station heat rates, station plant factors, system load, and fuel costs. And, as expected, simulated average operating costs decline with both system size and system load factor.[45]

Olson estimated an <u>ex post</u> long-run average cost function for 52 coal fired units and 24 non-coal units built between 1956 and 1965.[46] Presented is a simple multiple regression of average costs on the independent variables of the form

$$\log \$/\mathrm{kWh} = \sum_i b_i \log x_i \quad . \tag{II.13}$$

Where,

x_0 = constant

x_1 = unit size

x_2 = number of units in plant

x_3 = 1/plant factor, and

$x_4 - x_{12}$ = vintage dummies.

The three non-vintage variables all took appropriate signs and some level of significance. And both unit size scale economies and utilization economies are inferred.

However, in addition to mixing baseload and non-baseload units the average cost variable is constructed in an unusual way. Each firm is presumed to purchase fuel at the same cost per Btu and a fixed charge rate of 12 percent is applied to each unit. Since unit specific fuel prices and firm specific fixed charge rates were available this seems an unnecessary simplification. Since Olson's cost regression is not derived analytically from any firm level objectives it is difficult to interpret his estimated regression as a long-run average cost function. It would, therefore, be technically incorrect to interpret scale economies from his results. Nevertheless, Olson's results do support other studies which have found significant and important utilization scale economies.

Huettner attempts to estimate scale economies by estimating average capacity and average fuel cost equations directly.[47] Using a stepwise regression technique and considering variables such as capacity, fuel type, plant efficiency, and plant construction he develops multivariate regressions for both average capacity costs and average fuel costs in which only the reciprocal of size and a fuel type dummy appear on the RHS. This functional form is then used to examine costs for 13 vintage time periods from 1923 to 1968.

One result of the analysis is that, "minimum efficient plant size is slightly over 300 megawatts."[48] But, since the structures and equipment equations costs are measured with cost per kilowatt, as opposed to cost per killowatt hour, the analysis cannot be thought of as a traditional scale economy analysis, and this is acknowledged by the author.

It is Huettner's argument, though, that this approach may be more useful in investigating efficient plant choices because the useful lives of different plants are unknown and the implicit assumption of equal plant lives made by most may cause a "scale opposed bias." He argues, "While boilers and electrical equipment generally wear out physically at a relatively slow rate and do not rapidly decline below efficiencies attained when new, the more historically relevant parameter is economic life...Obviously, a more efficient unit has a longer economic life in years and, because of merit order dispatching practices, is likely to spread its capital charges over still more kilowatt hours of output...Because of the correlation between unit size and efficiency, there is a good possibility that capital charges based on accounting data have a scale-opposed bias." But larger, more efficient units are operated at higher temperatures and pressures, and, as we have noted, are subject to higher forced outage rates. And so physical obsolescence may well be an important consideration. In any event, Huettner provides no convincing evidence that systematically different depreciation charges are appropriate.

Two points are in order with respect to Huettner's methodology. First, the estimation of individual average cost regressions for capital and fuel costs assumes that capital and fuel may not be substituted. This seems unreasonable and the comments we made above on the Komyia analysis apply here as well.[50] Secondly, more flexible functional forms were available at the time of this research (1974). And the reliance on a simple linear functional form seems curious in this light.

But in spite of these methodological problems we should note that Huettner does refer to one of our primary concerns. With respect to the differences between baseload and non-baseload[51] plants Huettner notes,

> Generating plants may also be classified as base-load plants, cycling plants, and peak-load plants. Base-load plants are designed to operate at maximum fuel efficiency without being shut down for long periods of time. This may increase UCC (unit capacity costs) above that of cycling plants, which are designed to operate at the highest fuel efficiency consistent with rapid warm-up and cool-down during frequent shut downs. Cycling plants might tend to have a lower UCC due to looser tolerances on equipment as for example on the turbine blades.

Before being screened out by the stepwise regression technique Huettner attempted to capture this load type effect by including the plant heat rate as an explanatory variable in the capacity cost equation. But while this is a step in the right direction, the plant heat rate is likely to be a poor proxy for desired utilization. The plant heat rate depends not only on the level of desired utilization, but also on the availability and temperature of the condensing water and on the heat content of the fuel. Without controlling for the other determinants of plant efficiency it is unsurprising that the stepwise technique failed to retain this variable.

Galatin is interested in separating scale effects and technology effects in a multi-unit production function when one explicitly recognizes the instantaneous nature of electricity production. Since the level of fuel efficiency for a given plant depends on the instantaneous rate of output, and since Galatin is faced with the same annual FPC plant data used in all of the U.S. studies, his objective, "is to derive a functional form for the ex post production function which, as well as making economic sense, enables annual data to be used to estimate an essentially instantaneous process."

Essentially Galatin is confronting one form of the "aggregation problem." Here, two aggregated functional forms are presented which use annual data and which are based on a constructed disaggregated production function.

$$a_{it} = \alpha(X_{it}/X_{iK})^{-1} + \beta X_{iK} + \mu + v_{it} \qquad \text{(II.14)}$$

$$a_{it} = \alpha(X_{it}/X_{iK})^{-1} + \beta(X_{iK})^{-1} + \mu + v_{it} \qquad \text{(II.15)}$$

Where,

a_{it} = heat rate (Btu/kWh) for the ith machine during period t.

X_{it} = output of the ith machine in the tth period, and

X_{iK} = capacity of the ith machine.

Equations (II.14) and (II.15) were estimated using ordinary least squares over a sample of 812 observations on 158 plants. The observations were stratified by coal and non-coal types and by six technological vintage groups beginning with 1920 and ending with 1953. Since (II.15) yielded generally higher R-squares over the different vintage-fuel type cells it was selected as "the *ex post* production function."

With all of the estimated coefficients positive and generally significant across the vintage-fuel type cells Galatin next uses these estimates to infer scale economies. The positive estimate for α suggests declining fuel input per kilowatt hour with increasing capacity utilization for fixed size. From this Galatin argues "there are intra-capacity economies in the use of fuel, for if output increases in more than proportion to fuel input this implies that the average input of fuel input per unit of output decreases as full capacity is approached."[54]

In addition to the "intra-capacity" economies the positive estimate for β implies that "the fuel input per unit of output decreases the larger is the machine. Thus scale economies exist over the full range of the sample." While the degree of economies varies for different groups around the sample Galatin's results point to economies of both utilization and size throughout.

Galatin's concern for capturing the instantaneous nature of production, while notable, may have distracted him from equally important aspects of this technology. A first problem with the analysis here is that while Galatin develops a solid theoretical model of the industry early in the analysis the final functional form chosen bears almost no relationship to this model. The functional form develops solely from an interest in using aggregated data to represent an instantaneous production technology.

Our second concern is the same one we have had elsewhere. Both intra-capacity and inter-capacity economies may well depend on the desired level of unit utilization. There is no reason why the effect of size or actual utilization on unit heat rate should be the same for both baseload and non-baseload plants.

The single analysis in which availability rates were considered is provided by Lewis Perl. Perl's methodology involved first estimating hedonic cost equations for capital, and operating and maintenance costs over 245 coal plants built between 1965 and 1980. Plant capital costs were related to size, area wages, architectural firm dummies, and other variables. Operating and maintenance costs were regressed on plant size, the number of units in the plant, area wages, and regional dummy variables.

These costs were then inserted into a model which calculates a levelized cost of electricity. Levelized costs of electricity are a "constant annual charge for electricity which yield the same present value as actual annual charges over the life of a plant." The formula for the levelized cost is:

$$LC = \frac{\sum_{i=1}^{n} RR_i (1+\pi)^i}{\sum_{i=1}^{n} G_i (1+\pi)^i / (1+r)^i} \times 1/(1+r)^m \qquad \text{(II.16)}$$

Where,

RR_i = revenue requirement in year i,

G_i = generation in year i,

n = book life of the plant,

m = number of years from current date to start of operation,

π = nominal discount rate, and

r = inflation rate.

The revenue requirements in (II.16) are composed of "interest on debt, a return on equity capital, income and property taxes fuel costs and non-fuel operating and maintenance costs."[58] Fuel costs for the model were derived from the National Economic Research Asssociates World Coal Model which estimates and forecasts equilibrium coal prices for different geographical regions in the U.S. and Europe.

The plant output figure, G_i, used in the model are given by a sub-model which predicts equivalent availability based on plant size, age, vintage, and a number of plant characteristics. Here, Perl makes an assumption similar to one we make below, viz, that if a unit is available it is producing output.

For the analysis, Perl assumed a plant life of 30 years, a nominal discount rate of 8.6 percent, an inflation rate of 7 percent, and fixed other variables in the model. Next he varied the plant sizes and calculated levelized costs assuming an actual plant life time running from 1985 to 2014. A general conclusion reached by Perl was that, "The cost of electricity is about the same whether the unit size is 200 megowatts or 1,000 megawatts. This reflects the offsetting influences of size on availability factors and construction costs. Construction costs per kilowatt are higher for the smaller units but availability factors are also higher."[59]

While the Perl analysis is enlightening with respect to the effects of unit reliability we have two principal concerns. The first concern relates to the way in which unit efficiency enters the analysis. Total electricity costs in the model are comprised of operating costs and plant costs. Further, the parameter estimates in his plant cost regression will be consistent and unbiased only on the condition that there are no left out variables which are correlated with the RHS variables. But in Perl's plant cost equation there appears no proxy for the level of plant efficiency. That the level of plant efficiency exerts an independent and substantial influence on plant costs has been hypothesized and accepted by several researchers. Thus, it would seem that the plant size coefficient may well be biased here.

The level of unit efficiency is included as a determinate of operating costs, but the way it is included is unsatisfactory. In this model, plant heat rates are determined by way of a regression in which heat rates have been related to plant age, vintage, and a number of other plant characteristics. The level of plant efficiency is, therefore, determined by the characteristics of a plant. Since this plant efficiency choice is not subjected to any cost minimizing rules it is easy to see how the model may assign either more or less than the cost minimizing level of efficiency and that a distorted picture of long-run average costs may follow.

The second general concern we have with the Perl analysis is that no theoretical structure is developed. Consequently, no hypotheses are developed that can be accepted or rejected. The analysis is interesting due to the number of engineering influences it accommodates. But the conclusions remain subject to concern because they are not subject to rejection.

Summary

In summarizing the literature that has been reviewed two general observations seen worthwhile. First, scale analyses of this industry which have either ignored[61] utilization or folded utilization into an output variable[62] have uniformly found plant scale economies throughout. However, we would contend that the economies discovered in these analyses must be shared between the effects of plant size and the level of utilization.

Secondly, studies which have recognized the utilization dimension of capital heterogeneity and have attempted to capture the independent effects of size and utilization have without exception found substantial and significant economies of utilization.

If a general consensus were to emerge from this body of research it would seem to be that to adequately characterize this technology one must first control for the salient dimensions of capital heterogeneity. While there may be disagreement, two of the more important dimensions appear to be plant utilization and plant efficiency.

With respect to plant utilization we have seen only two studies which have attempted to relate costs to desired utilization.[63] Unfortunately, both of these studies employed proxies which inadequately described desired utilization.

64

The last study reviewed acknowledged the necessary decomposition of *ex post* utilization into its two components: unit reliability and desired utilization. But the principle of cost minimization was not employed in this analysis.

What seems to be needed at this point is a model which presumes cost minimizing behavior that separates the effects of desirability and availability and that allows for capital heterogeneity. We begin developing a model along these lines in Chapter III.

CHAPTER II: ENDNOTES

1
An alternative definition of scale economies is that developed by Baumol, et al. in the contestable markets literature. Here, scale economies occur for output regions wherein ray average costs decline with output along a ray defining a fixed output proportion in multiple output space. See W. J. Baumol, "Contestable Markets: An Uprising in the Theory of Industry Structure," American Economic Review, Vol. 72, no. 1 (March, 1982), p. 6.

2
Y. Barzel,"The Production Function and Technical Change in the Steam-Power Industry," Journal of Political Economy, 72 (April, 1964).

3
Throughout the article Barzel uses "load factor" instead of the correct "plant factor." Load factor is defined as the ratio of actual output for the firm to the output which would be realized if output were produced continuously at peak demand.

4
Barzel, op. cit. p.134.

5
Ibid.

6
Ibid.

7
P. Dhrymes and M. Kurz, "Technology and Scale in Electricity Generation," Econometrica 32 (July, 1964), 287-315.

8
Ibid, p.298.

9
Ibid, p.310.

10
See pp. 312-13 for a discussion of this calculation.

11
Ibid, p.313.

12
J. Roth, An Econometric Approach to Technological Change and Returns to Scale in Steam-Electric Generation, Ph.D. dissertation, Michigan State University, East Lansing, 1971.

13
Ibid, p.138.

14
Ibid, p.163.

15
T. Cowing, "Technical Change and Scale Economies in an Engineering Production Function: the Case of Steam-Electric Power," Journal of Industrial Economics, 23 (Dec., 1974), pp.135-52.

16
Ibid. For a fuller discussion of the approach see pp. 135-36.

17
Ibid, p.144.

18
Returns to scale (p. 147) in the model are given by

d/d-b.

19
Design heat rates were found in Power, 1970-79.

20
M. Fuss, "Factor Substitution in Electricity Generation: A Test of the Putty-Clay Hypothesis," in Production Economics: A Dual Approach to Theory and Applications, eds. M. Fuss and D. McFadden, Amsterdam: North Holland, 1978.

21
Ibid, p. 194.

22
Note that this is the same adjustment Galatin (op. cit.) made.

23
See Fuss' discussion of the difficulty of sorting these effects out (pp. 195-96).

24
J. Stewart, "Plant Size, Plant Factor, and the Shape of the Average Cost Function in Electric Power Generation: A Nonhomogenous Capital Approach," Bell Journal of Economics, 1979, pp. 549-65.

25
The reader will note that as in Cowing (1974) Stewart ignores labor cost in his analysis.

26
The functional form of the plant cost function did not permit an explicit solution for α^*.

27
See the Stewart's (op. cit.) footnote 23, p. 562.

28
Ibid, p. 564.

29
K. Lomax, "Cost Curves for Electricity Generation," Economica, 19, 1952.

30
Ibid, p. 195.

31
It is unfortunate that at this earl writing the popularity of publishing t-statistics and sample size along with the regression coefficients had yet to catch on.

32
R. Shephard, Cost and Production Functions, Princeton: Princeton University Press, 1953.

33

Lomax, op. cit., p. 195.

34
Ibid, p. 197.

35
Kirchmayer, et al., op. cit.

36
See for instance S. Z. Haddad and R. French, "The Economics of Reliability and Scale in Generating Unit Size Selection," Proceedings of the American Power Conference,42, 1980 pp. 680 - 86. N. Hall ,N. Tibberts, and M. Adams,

"Analysis of Interrelationships Among System Loads, Capacity Requirements and Generating Unit Availability," Prodeedings of the American Power Conference, 41, 1979, pp. 1035 - 42. C. W. Watchorn, "Elements of System Capacity Requirements," American Institute of Electrical Engineers - Transactions, 70, 1951, pp. 1163 - 85.

37
Kirchmayer, op. cit., p. 600.

38
R. Komyia,"Technical Progress and the Production Function in the U.S. Steam Power Industry," Review of Economics and Statistics, 44 (1962), 156-66.

39
Ibid, p. 158.

40
See Kirchmayer, et al., op. cit.

41
The same criticism was made by Roth, op. cit.

42
S. Ling, Economies of Scale in the Steam-Electric Power Generating Industry. Amsterdam: North Holland, 1962.

43
Ibid, p. 20-21.

44
Ibid, p. 39-41. This indicates the endogenous nature of plant factor from a system perspective. That other unit or plant level studies seem to be merely controlling for plant factor effects seems to ignore the fact that intended utilization is determined at the system level.

45
That average costs decline with system size results from the fact that larger systems can include more larger plants. With no availability penalty for larger units this is precisely what one would expect.

46
C. Olson, Cost Considerations for Efficient Electricity Supply. East Lansing: Michigan State University Public Utilities Institute, 1970.

47
D. Huettner, Plant Size, Technological Change, and Investment Requirements. New York: Praeger Press, 1974.

48
Ibid, p. 103.

49
Ibid.

50
Komyia, op. cit.

51
Huettner, op. cit., p. 53.

52
M. Galatin, Economies of Scale and Technological Change in Thermal Power Generation. Amsterdam: North Holland, 1968.

53
Ibid, p. 100.

54
Ibid, p. 120.

55
Ibid.

56
Lewis Perl, "The Current Economics of Electric Generation from Coal in the U.S. and Wester Europe," presented at the International Scientific Forum on Reassessing the World's Energy Prospects, National Economics Research Associates, Paris, 1982.

57
Ibid, p. 2.

58
Ibid, p. 12.

59
Ibid, p. 6.

60
See for instance Cowing, op. cit., and Stewart, op. cit.

61
Dhrymes and Kurz, op. cit. and Roth, op. cit.

62
T. Cowing, op. cit.

63
Bazrel, op. cit., and Huettner, op. cit.

64
Perl, op. cit.

CHAPTER III

A MODEL OF THE STEAM-ELECTRIC TECHNOLOGY

In this chapter we develop a model of the steam-electric generation process which incorporates observations set out in Chapters I and II. Section III.1 provides a general discussion of the methodology employed. Sections III.2 through III.4 develop the model, and section III.5 provides estimates of the plant cost function.

3.1 GENERAL

The model developed below describes the steam-electric production technology in terms of both engineering and economic factors. This is in contrast to the neoclassical approach commonly used by economists to describe production relationships, but the approach does offer certain advantages.

The analytical vehicle normally used by economists to represent production relationships is the neoclassical production function. A key characteristic of the neoclassical production function is its general applicability across different technologies. Defined to relate the maximum technologically feasible output with the level of inputs, the neoclassical approach maintains a prior assumption that the process under investigation is previously optimized with respect to engineering factors. As such, the engineering peculiarities of different technologies are ignored, and the analytical focus is limited to economic characteristics.

The engineering-economics approach, on the other hand, folds engineering and economic factors into the same analysis. Where the neoclassical approach is general, the engineering-economics approach employs engineering information that is specific to the technology being studied. As a result, the final form of the model will be uniquely appropriate for the technology it is developed for.

An obvious advantage of the engineering -economics approach is that it provides a more complete description of the technology. While preserving the economic characteristics of the technology, the engineering - economics approach provides a much richer description of the production process under investigation. In addition to the scale[1] and substitution effects normally estimated in a production study, one may also investigate the influence that specific engineering factors have on the technology.

Moreover, the added descriptive ability of the engineering-economics approach is especially valuable when investigating production relationships for a regulated industry such as electricity generation. Informed regulatory oversight depends not only on the verification of economic characteristics but also on why these characteristics exist. In this regard, the engineering-economics approach will be seen to be ideally suited to the task of exploring both the economic and the engineering factors that structure the steam-electric production process.

3.2 THE MODEL

The general problem for the firm in this model can be described as follows. An exogenous baseload output level is first given to the firm. Given this load, the firm has the problem, *ex ante*, of choosing equipment to service the load at minimum expected total cost.[2]

The loads considered by planners in this model are restricted to baseloads so that we do not confuse the relative impacts of unit availability and desired utilization. By definition, a baseload is a load that is of a constant level throughout the period of investigation. Consequently, restricting output to take the form of a baseload presumes that the desired utilization of the chosen equipment will be one, and the influence of unit availbility can be isolated.

More specifically, the baseload output for the boiler-turbine-generator (BTG) unit will be defined over an instantaneous rate of power and a utilization intensity. While the instantaneous rate of power for the unit is defined by the size of the BTG unit the anticipated utilization factor for the unit will be defined by the expected availability rate, a(k). Combining these conditions we have a direct relationship between expected output, $\hat{Q}$, and unit size. This relationship is:

$$\hat{Q} = 8760a(k)k. \tag{III.2}$$

Where,

8760 = number of hours in a year,

k = instantaneous rate of power for the unit, kW,

$a(k)$ = expected availability rate for the unit.

Regarding substitution possibilities in the model, we assume a putty-clay world where capital and fuel are combined to produce electricity. The level of unit efficiency is presumed to be variable and endogenous in the blueprint stage. But once the unit is built we assume that the conversion rate of fuel into electricity is fixed and unalterable. Under these conditions, expected <u>ex post</u> total fuel and capital costs are:

$$SRTC(\alpha_0, k_0, P_f, r) = \alpha_0 8760k_0 a(k_0)P_f + rP_k(\alpha_0, k_0)k_0. \tag{III.3}$$

Where,

α_0 = <u>ex post</u> unit heat rate (Btu/kWh),[3]

P_f = expected fuel price ($/Btu),

r = expected service price of capital (interest and depreciation), and

$P_k(\alpha,k)$ = per kilowatt plant cost.

While the model given in (III.3) provides a general description of the major engineering and economic features of BTG costs it is limited with respect to a number of less important cost components. Labor, materials, administrative, and other costs are ignored. These cost components are excluded for two reasons. First, while unit level economies may be affected by these other inputs their influence is likely to be inconsequential. Cost shares typically run 50 percent fuel, 40 percent capital, and 10 percent labor. So (III.3) should capture the most important cost components. Further, none of the studies reviewed in Chapter II above attributed overall unit or plant level economies to inputs other than fuel and capital. Secondly, substitution possibilities between capital and labor and the left out inputs are negligible even in the long-run. Consequently, the implicit substitution elasticities estimated within the context of the model (III.3) should be free of bias.

Further, the model abstracts from the effects of time. r is assumed to represent the service price of capital in a single year. A sufficient condition for r to be constant with respect to time would involve assuming (1) that the unit size is derated for depreciation regularly with time, and (2) that unit availability and efficiency is constant with respect to time. Under these conditions the service quality of capital would be constant. In reality the issue is much more complex. Unit efficiencies and availability do not significantly decline with time.[4] But, in later years, economic depreciation caused by changing relative fuel prices or technology improvements may reduce the desired utilization of the unit. All things considered, the focus on a single year may indeed misrepresent the information one might obtain with a longer-term analysis, but the more complete model would require the formation of expectations regarding future economic depreciation, and this is outside the scope of the analysis presented here.

3.3 *EX ANTE* COSTS

While the expected short-run technology is characterized by fixed coefficients the firm is faced with the ex ante problem of choosing the level of unit efficiency which minimizes the expected accounting costs of serving the given baseload. The plant cost - efficiency possibilities the firm is faced with are given by the plant cost function, $P_k(\alpha,k)$. The plant cost function, in our context, is considered to be an hedonic plant cost pricing schedule which is known to the firm. Briefly, we can characterize the expected efficiency plant cost tradeoff as follows. We expect $\partial P_k(\alpha,K)/\partial\alpha<0$ because less efficient units require less efficiency related equipment. We also expect $\partial^2 P_k(\alpha,k)/\partial\alpha^2>0$. For fixed plant size we expect plant costs to decline at a decreasing rate with declining efficiency.[5]

For the given baseload requirement, *ex ante* total costs are determined by the unit heat rate:

$$TC(\alpha,k,P_f,r) = \alpha 8760ka(k)P_f + rP_k(\alpha,k)k. \qquad \text{(III.4)}$$

Developing the *ex ante* cost function we first minimize (III.4) with respect to the heat rate:

$$\partial TC/\partial\alpha = 8760ka(k)P_f + \partial P_k(\alpha,k)/\partial\alpha kr = 0$$

or (III.5)

$$8760a(k)P_f = -\partial P_k(\alpha,k)/\partial\alpha r \Big|_{\alpha}^{*}.$$

Since increasing the heat rate (decreasing efficiency) should result in lower per kilowatt unit costs the RHS of (III.5) should be positive. Intuitively, this is a typical neoclassical result which implies that the energy efficiency of a planned plant, *ceteris paribus*, should be reduced so long as the resulting amortized costs are greater than the incremental fuel costs.

The second order condition is given in (III.6):

$$\partial^2 TC/\partial\alpha^2 = \partial^2 P_k(\alpha,k_0)/\partial\alpha^2 r. \qquad \text{(III.6)}$$

The second order condition holds so long as $\partial^2 P_k(\alpha,k_0)/\partial\alpha^2 > 0$. Plausibly, this would be the result if the cost penalty for improving efficiency were greater for relatively efficient units as compared to relatively inefficient units. Implicitly then we have the cost minimizing heat rate, α^{*}, as follows:

$$\alpha^{*} = h(P_f, k, r).$$

Using the assumptions above and (III.4) the *ex ante* cost function becomes:

$$LRTC^{*}(k,r,P_f) = 8760h(k,P_f,r)ka(k)P_f + P_k(h(k,P_f,r),k)kr. \qquad \text{(III.7)}$$

Since a unique relationship is preserved between unit size, k, and output, the *ex ante* cost function, as expected, is shown to be a function of output and prices.

3.4 THE PLANT COST FUNCTION

In section III.3 we completed the development of the theoretical model describing the steam-electric technology in terms of fuel costs and capital costs. In this section we explore the determinants of capital costs and present estimates of the plant cost function, $P_k(\alpha,k)$.

3.4.1 General

Mentioned above, the plant cost function, $P_k(\alpha,k)$, represents a pricing schedule of plant costs for different plant characteristics. We assume that this schedule is known to the firm. As this function captures not only technical and economic information in the equipment manufacturing production process but also market structure conditions in the equipment industry some assumption about market structure effects is required. Here, we make the weakest assumption possible, viz, that equipment prices are proportional to production costs in the equipment manufacturing industry. While an assumption of perfect competition in the equipment industry would be sufficient for our purposes it would also be both unrealistic and stronger than needed. A weaker, yet sufficient, assumption is that there is no price discrimination with respect to any characteristics of the purchasing electric utility.

With respect to our expectations on how plant costs should respond to changes in efficiency and unit size we discuss first the expected cost effects of efficiency. Improving unit efficiency involves, primarily, the introduction of strengthened materials which allow higher temperature and pressure conditions, and the addition of regenerative pre-heaters and/or reheat units.[6] Since each of these physical additions require a capital expenditure we expect $\partial P_k(\alpha,k)/\partial\alpha<0$. However, as the unit becomes more efficient we expect that additional efficiency will come at the expense of a more than proportionate increase in plant costs. That is, we expect $\partial^2 P_k(\alpha,k)/\partial\alpha^2>0$.

With respect to the effect of size on per kw plant costs engineers frequently employ a "six-tenths" rule. This simply relates to the analogy that as volume increases for a sphere the surface area increases by approximately "six-tenths" of the increase in volume. Since electric capacity is more nearly related to unit volume, and costs are more nearly related to the surface area, increases in capacity should lead to reductions in per kilowatt costs. That is, $\partial P_k(\alpha,k)/\partial k<0$. However, we expect this relationship to be stronger for smaller plants than for larger plants, $\partial^2 P_k(\alpha,k)/\partial k^2>0$.

Finally, we expect the cross partial elasticity to be governed by two opposing forces. Ceteris paribus, we expect that a one percent reduction in the heat rate will be relatively more expensive for a smaller plant than for a larger plant, $\partial^2 P_k(\alpha,k)/\partial\alpha\partial k>0$. This is because the expenditures for efficiency improvement are spread over a smaller base in a smaller plant. However, we agree with Stewart (1979, p.556) that the fabrication requirements may be more complicated and expensive in a larger plant, $\partial^2 P_k(\alpha,k)/\partial\alpha\partial k<0$. The sign of the cross partial elasticity should depend on the relative importance of these two affects.

3.4.2 ESTIMATION OF THE PLANT COST FUNCTION

For estimating the plant cost function we have selected a translog functional form.[7] The reasons for its selection are

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are twofold. First, and more importantly, is the fact that the translog specification allows all of the size - efficiency effects discussed above to occur. And secondly, the translog form can be viewed as a second order Taylor approximation to any continuous plant cost function.[8] The equation to be estimated is:

$$\ln P_{kt} = B_0 + B_1 \ln(\alpha-\tilde{\alpha})_t + B_2 \ln(\alpha-\tilde{\alpha})^2_t + B_3 \ln k_t + B_4 \ln k^2_t + B_5 \ln(\alpha-\tilde{\alpha})\ln k_t + \Sigma_i B_i x_{i,t} + e_t . \tag{III.8}$$

Where,

x_i = dummy variables indicating regionality, the number of units in a plant, and other variables, and

$\tilde{\alpha}$ = lower bound heat rate (6000 Btu/kWh).[9]

We used least squares to estimate (III.8) for 32 newly constructed coal fired units which began operation in the period 1972-1978 and were reported in the Department of Energy publication, <u>Steam-electric Plant Costs and Annual Production Expenses</u>. Covered in this publication are plant costs and other data for 96% of total U.S. generation capacity.[10]

An implicit assumption here is that all new coal plants were designed with the expectation of being baseload units. <u>Ex ante</u>, a particular unit's load is determined by the expected SRMC for the unit in comparison to other units in the firm and in comparison with the expected cost of power from

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from other sources. Thus, one would ideally want to rank expected SRMC for all coal units in the system, compare these with the expected system baseload, and classify the baseload units as those units which would be economically dispatched without load constraints over the period. Unfortunately. we do not have expected SRMC for all resources for any of the firms who have built the units in our sample. However, 1982 average fuel costs (mills per kWh) were 18.65 for coal plants, 26.50 for gas-fired plants, and 51.59 for oil-fired plants.[11] Since fuel costs account for more than 95 percent of marginal costs, and since different units are dispatched based on their ranked marginal cost, the baseload assumption is likely to be a good one.

Since technology change is not an interest of this study all plant costs were adjusted to 1975 constant dollars using the Handy Whitman Index of Public Utility Construction Costs.[12] That is, we assume that firms which built units across this period had access to the same technology in the design stage.[13] Additionally, only single unit or multiple identical unit plants were used for the study. We would expect multi-unit construction economies in that it should be less than proportionately expensive to construct multiple-units. To capture this affect we have included the log of the number of units on the RHS of (III.8).

But in addition to the variables mentioned above we controlled for two other plant related variables: whether or not a cooling tower is required[14] and whether the unit used subbituminous or lignite, or one of the higher heating value coal types.[15]

The cooling tower dummy takes a value of 1 if a cooling tower is required and 0 otherwise. Large amounts of water are required to condense the steam once expanded across the turbine blades. Those units which are fortunate enough to be situated on large bodies of flowing water (oceans, large rivers) are thus spared a major construction expense when compared to those who must use cooling towers to cool the effluent, even when the size and efficiency levels are the same. And the cooling tower dummy is intended to capture the cost effects of cooling towers.

The heat value of the coal has two effects on plant costs. First, lower heating value coals (lignite or subbituminous) imply the need for larger furnace areas in trying to achieve a given Btu input when compared to the higher heating value coals (bituminous and anthracite). This is simply because a larger volume of coal must be introduced to the furnace when using low heat value coal.

But additionally, a one percent improvement in efficiency for a unit which uses lower heating value coal may be more expensive than for its hard coal counterpart. Considering the furnace alone, a one percent improvement in efficiency implies a larger furnace area to be insulated for low heating value coals when compared to the high heating value coals. To control for these effects we have included (1) a dummy (DSL) for coal type which takes on the value of 1 for subbituminous and lignite coal, and zero otherwise, and (2) an interaction variable of heat rate on the coal type dummy variable. Consistent with our discussion we expect the coefficient on DSL to be greater than zero and the coefficient on the interaction term should be less than zero.

The remaining shift variables included in the regression were all regional dummy variables. Though our dependent variable includes only equipment costs some construction costs are included in the data, and to the extent that these construction costs vary with the regions these dummy variables should capture this information. For comparison, the regions chosen were the same as in Stewart (1979). The regions are: Central and Southeast (FPC regions II, III, IV), West (VI, VII, VIII), Northeast (1), and Gulf (V).

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3.5 Regression Results

Ordinary least square estimates for the plant cost function are given below in Table III.1

TABLE III.1

Plant Cost Regression Estimates

Dependent Variable: ln (per kw equipment costs)

Variable	Coefficient	Standard Error
Constant....................	580.1105	341.3448+
$\ln(\alpha-\tilde{\alpha})$....................	-135.4752	80.8679+
$(\ln(\alpha-\tilde{\alpha}))^2$.................	7.9859	4.8374+
lnk........................	-4.4169	11.5243
$(\ln k)^2$.....................	-0.0016	0.1144
$\ln(\alpha-\tilde{\alpha})\ln k$.................	0.5225	1.3819
ln number of units in plant	-0.1366	0.1164
Central-South Dummy........	0.1256	0.1645
West Dummy.................	0.2275	0.1257+
Northeast Dummy............	0.5571	0.1922*
Cooling Tower Dummy........	0.2350	0.0906*
Coal Type Dummy (DSL)......	25.7841	18.8882+
$\ln(\alpha-\tilde{\alpha})\times$Coal Dummy.........	-3.0709	2.2577+

$R^2 = .7207$

Adjusted $R^2 = .5443$

$F(12,20) = 4.0854$

+ = significant at 80 percent

* = significant at 95 percent (two tailed tests)

Examining Table III.1 one sees that several of the variables obtain the expected sign and some degree of significance. Of concern, however, is the apparent lack of significance for the size variable.[16] But here we should note that with the squared terms and interactions in the model the elasticities and standard errors for both the size and heat rate variables vary for different locations in the sample.[17] These elasticities and their standard errors are given below in Tables III.2-III.4.

The plant cost elasticities with respect to size are given in Table III.2. These elasticities take on the expected sign and some level of significance for all heat rate levels except the highest. The largest degree of significance occurs near the sample mean heat rate; the lack of significance in the highest heat rate group is of little concern because we had only four units in our sample with heat rate greater than 10,800. Interestingly, the size elasticities tend to increase with larger heat rates, suggesting that the effect of size on plant costs is stronger for more efficient plants. But this is also seen with the positive coefficient estimate on the interaction term in Table III.1 .

TABLE III.2

PLANT COST ELASTICITIES WITH RESPECT TO UNIT SIZE

α	K(MW)	250MW	500MW	750MW	1000MW
9000	B	-.2517	-.2541	-.2554	-.2564
	SE	.2298+	.2163+	.2317+	.2532+
9500	B	-.1713	-.1736	-.1749	-.1759
	SE	.0837*	.0663*	.0794*	.0992*
10000	B	-.1012	-.1036	-.1049	-.1049
	SE	.0304<	.0095<	.0205<	.0388<
10500	B	-.0396	-.0419	-.0433	-.0442
	SE	.0402+	.0162+	.0254+	.0425+
11000	B	.0152	.0129	.0116	.0106
	SE	.0937	.0668	.0745	.0904

+ = significant at 80 percent (two tailed)

* = significant at 95 percent

<= significant at 99.5 percent

	Mean	Minimum	Maximum
k:	507 MW	153.5 MW	1300 MW
α:	10,296	9,560	11,771

TABLE III.3

PLANT COST ELASTICITIES WITH RESPECT TO $(\alpha-\tilde{\alpha})$ for DSL = 1

α	K(MW)	250MW	500MW	750MW	1000MW
9000	B	-7.7894	-6.5648	-7.2152	-7.0647
	SE	23.8428	22.6560	22.8127	23.3056
9500	B	-5.3298	-4.9676	-4.7555	-4.6050
	SE	11.9050	10.7917	10.9916	11.5150
10000	B	-3.1895	-2.8274	-2.6152	-2.4647
	SE	5.1299	4.0806	4.3179	4.8679
10500	B	-1.3048	-.9427	-.7305	-.5800
	SE	1.9471	.9542+	1.2245	1.7979
11000	B	.3722	.7343	.9465	1.0969
	SE	1.3066	.3638*	.6636*	1.2579+

+ = significant at 80 percent (one tailed)

* = significant at 90 percent

number of units for which DSL = 1 = 15

	Mean	Minimum	Maximum
k:	505 MW	303 MW	1300 MW
α:	10,676	10,143	11,771

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TABLE III.4

PLANT COST ELASTICITIES WITH RESPECT TO $(\alpha-\bar{\alpha})$ for DSL = 0

α	K(MW)	250MW	500MW	750MW	1000MW
9000	B	-4.7185	-4.3563	-4.1442	-3.9937
	SE	9.3141	7.9938	8.0719	8.5085
9500	B	-2.2588	-1.8566	-1.6845	-1.5340
	SE	3.3728	2.1260+	2.2473	2.7145
10000	B	-.1185	.2435	.4557	.6062
	SE	1.8154	.6326	.7913	1.2851
10500	B	1.7661	2.1283	2.3404	2.4909
	SE	3.2273	2.1009+	2.2927+	2.8098+
11000	B	3.4432	3.8053	4.0175	4.1679
	SE	6.6767	5.6004	5.8216	6.3596

+ = significant at 80 percent (one tailed)

number of units for which DSL = 0 = 17

	Mean	Minimum	Maximum
k:	558 MW	153,5 MW	1158 MW
α:	9,986	9,560	10,468

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Tables III.3 and III.4 give estimates of the heat rate plant cost elasticities for low heating value and high heating value coal units, respectively. For the low heating value coals (DSL=1) we obtain the expected sign over most of the sample space. But we find only one location where any degree of significance obtains. Since heat rates for these plants are generally higher it is unsurprising that we find the highest level of significance in a relatively high heat rate location. And since the minimum heat for this group of units is 10143 the lack of significance for estimates below this level is of little concern.

Results similar to those above are found in Table III.4 (DSL=0). The single location where the expected sign and any degree of significance is obtained is found at a relatively low heat rate value consistent with the lower heat rates found in these units. And, since the highest heat rate found in this group of units is 10,468 the coefficient estimates in the 10,500 and 11,000 heat rate groups are of little interest.

But we have two remaining concerns with the values in Tables III.3 and III.4: the positive coefficient estimates for the highest heat rate group and the general lack of significance. While there may be a host of reasons why the heat rate partials behave so curiously in the high heat rate group our concerns are tempered by the fact that we have only four plants with a heat rate of 10,800 or greater.

With respect to the general lack of significance for most of the estimates we note that this is likely to be due to the high degree of collinearity between the heat rate variable and its square. The simple correlation coefficient between the heat rate variable and the squared term was .9999 across the sample. On this point it is apparent that the information in our data set has failed to measure the independent affect of the squared term.

Summary

The purpose of this chapter was to (1) develop a theoretical model of baseload electricity generating technology that would ultimately allow us to infer the extent of scale economies in this industry, and (2) present estimates of the capital cost component in average total generating costs. The completion of these two tasks lays the groundwork for the further consideration of fuel costs and the inference of scale (dis)economies in Chapter IV.

Our early discussions in the chapter were devoted to issues of methodology. The traditional neoclassical approach to describing technology was contrasted with what was referred to as an engineering-economics approach. While the neoclassical approach has the benefit of being generally applicable across different technologies, the engineering -

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economics approach utilizes technology specific engineering information. The engineering - economics approach was selected for this study primarily because of the added dimension of engineering information it is capable of providing to the regulators of this industry.

The fully developed model defined the long-run total cost function to be, as one would expect, a function of anticipated output and relative factor prices. Given our exclusive consideration of baseload units, output in the model was defined by an exogenous unit size and the anticipated unit availability rate. Further, total fuel costs and total capital costs (labor costs are ignored) are defined by an endogenous unit efficiency as well as the prices of fuel and capital.

The remainder of the chapter was devoted to justifying and estimating the plant cost function. Consistent with the hedonic approach of engineering-economics, we usd a translog form to predict per kilowatt plant prices with plant size, plant efficiency, regional dummies, fuel quality, and whether or not the plant required cooling tower investment expenditures. The discussion of the plant cost estimates concluded with a summary of the regresion results. We now turn our attention to the prediction of plant efficiency, average fuel and capital costs, and the inference of unit level scale (dis)economies.

ENDNOTES: CHAPTER III

[1] An estimate of scale elasticities is the point of interest here. The scale elasticity is usually defined as the percentage change in output given a proportional change in all inputs. However, Fuss (1978, p. 193) notes that examining returns to scale from the production side "is really only appropriate for homothetic production functions, where expansion along any ray from the origin of the input space is unambiguous." Alternatively, and more general, is the definition of scale elasticities which comes from the cost function side. Here the scale elasticity is defined as the percentage change in average cost, given a one percent change in output, fixing relative factor prices.

[2] The term ex ante will be used in this analysis to signify the blueprint or planning stage.

[3] The assumption of an average heat rate over the period is a simplification. The efficiency of a particular unit varies nonlinearly with the instantaneous rate of utilization. However, the assumption would certainly be more seriously violated for nonbaseload units where utilization rates vary throughout the period. For baseload units where output is produced at a constant rate the average heat rate over the period should be a good approximation to the instantaneous heat rate.

[4] There is some evidence that unit efficiencies decline somewhat over time. If this reduction were significant then the quality of capital would change with time and the static framework used in this analysis would not be valid. However, Huettner (1974), op. cit., and Perl (1982), op. cit., have both mentioned that this reduction is only slight.

[5] A fuller discussion of these effects is provided below in III.5.

[6] Reheat units remove steam from intermediate turbine stages, reheat the steam, and reintroduce the steam at the next turbine blade. When regenerative preheaters are used the steam is again bled off from an intermediate turbine

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blade. Rather than being reheated, however, the steam is used to preheat boiler feedwater. Both techniques improve cycle efficiency because the steam re-enters the cycle at higher enthalpy. See B.G.A. Skrotski and W.A. Vopot, Power Station Engineering and Economy (New York: McGraw Hill, 1960), pp.62-67.

7
The reader should note that while we have chosen the translog functional form for estimating the plant cost function, long-run average fuel and plant costs are estimated using the engineering-economic construct developed in sections III.2 - III.4.

8
Our primary motivation in choosing the translog form was its' flexibility in allowing all of the effects we have discussed to occur. Interpreting the translog function as a second order approximation to the true but unknown function has been gaining popularity (Varian, 1978 p.128, Spady and Friedlander, 1978, p. 162) but White (1980) notes that this interpretation holds only under fairly restrictive conditions (orthogonality of regressors for instance).

9
Since one kilowatt hour is equivalent to 3415 Btus' heat rates below 3415 are thermodynomically impossible. State of the art production techniques impose a practical minimum of 6000-7000 Btu. McKay (1977) investigated the sensitivity of employing different heat rate lower bounds in a similar plant cost function and found this sensitivity to be negligible. Also in 1972 the lowest plant heat rate observed in the country was 8,670 for Duke Power Company's Marshall plant.

10
The title given in the text was the title used until 1979. Beginning in 1979 gas turbine units were added and the title was changed to Thermal-electric Plant Cost and Annual Production Expenses. And beginning in 1982 hydroelectric units were included, changing the title to Historical Plant Cost and Annual Production Expenses.

11
In 1982 the average fuel cost (mills per kWh) was 18.65 for coal plants, 51.59 for oil plants, and 26.50 for gas fired plants. See U.S. Department of Energy, Historical Plant Cost and Annual Production Expenses for Selected Electric Plants 1982. Washington, D.C. ; U.S. Government Printing Office, 1982, pp.92. Also, we provide a complete description of our data in the appendix.

12
Whitman, Requardt and Associates, <u>Handy-Whitman Index of Public Utility Construction Costs</u>. Baltimore: Whitman, Requardt and Associates, 1983.

13
Technology change in this industry is usually manifested in efficiency improvements. Across all fossil fuel plant types the average thermal efficiency was 32.9 percent in both 1972 and 1978. While there may be disguised technology improvements for coal plants hidden in these figures it is unlikely that there were significant improvements in thermal efficiency over the period.

14
Cooling tower investment cost may range from $6 to $40 per kW (1972 dollars) depending on the type of system required. See Hill (1977, p.304) for a discussion.

15
The approximate heating values for the different coal types are as follows:

Anathracite	13,000 Btu/lb
Bituminous	12,400 Btu/lb
Subbituminous	9,500 Btu/lb
Lignite	6,700 Btu/lb

In our own sample there were 15 units which used either subbituminous or lignite and 17 units which used either anathracite or bituminous coal.

16
Our basis for including both the size and heat rate terms rests more on theory than on goodness of fit. By deleting all capacity terms our R^2 fell slightly to .7039; deleting all capacity and heat rate terms the R^2 fell only to .6671. Indeed, the regional dummies alone yielded an R^2 of .5081.

17
The plant cost elasticities and their respective standard errors are as follows:

$$\partial \ln P_k / \partial \ln k = B_3 + 2B_4 \ln k + B_5 \ln(\alpha - \tilde{\alpha})$$

$$\partial \ln P_k / \partial \ln(\alpha - \tilde{\alpha}) = B_1 + 2B_2 \ln(\alpha - \tilde{\alpha}) + B_5 \ln k + B_{12}\, DSL$$

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$$SE(\partial/\partial \ln k) = Var(B_3) + 4Var(B_4)(\ln k) + Var(B_5)(\ln(\alpha-\alpha))$$

$$+ 4Cov(B_3, B_4)\ln k + 2Cov(B_3, B_5)\ln(\alpha-\tilde{\alpha})$$

$$+ 4Cov(B_4, B_5)\ln(\alpha-\tilde{\alpha})\ln k$$

$$SE(\partial/\partial \ln(\alpha-\tilde{\alpha})) = Var(B_1) + 4Var(B_2)(\ln(\alpha-\tilde{\alpha}))$$

$$+ Var(B_5)\ln k + Var(B_{12})DSL + 4Cov(B_1, B_2)\ln(\alpha-\tilde{\alpha})$$

$$+ 2Cov(B_1, B_5)\ln k + 2Cov(B_1, B_{12})DSL + 4Cov(B_2, B_5)\ln(\alpha-\tilde{\alpha})\ln k$$

$$+ 2Cov(B_2, B_{12})\ln(\alpha-\tilde{\alpha})DSL + 2Cov(B_5, B_{12})DSL(\ln k).$$

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CHAPTER IV

AVERAGE TOTAL COSTS AND SCALE ECONOMIES

In this chapter we begin by discussing the solution of the model developed in Chapter III and by providing some evidence that the model predicts cost minimizing heat rates and average costs reasonably well. In Section IV.2 we use the model to simulate heat rates and costs for a variety of different cases. A detailed discussion of the simulation results is also provided in this section.

4.1 THE *EX ANTE* COST FUNCTION

In Chapter III we presented our theoretical model and provided the plant cost function which yielded per kilowatt capital costs. Our focus is now on adding fuel costs to the capital costs and estimating average total costs and scale economies. Using the plant cost function estimates given in Table III.1, inserting expected prices and availability rates, and solving (III.4) for $\hat{\alpha}^{*}$[1], the cost minimizing heat rate, one could use (III.6) to find minimum average cost for each unit in the sample. Unfortunately, however, the plant cost functional form does not permit one to solve explicitly for $\hat{\alpha}^{*}$. Instead we have used a numerical search procedure to calculate the cost minimizing heat rate and minimum average cost for each unit in our sample.

While the search procedure does not yield a set of coefficients and associated t-ratios that would allow us to confirm the model there are other ways of validating the model. To do this, we have regressed the actual heat rates and average costs on the values that were predicted by the model. The results are given below in Tables IV.1 and IV.2.

TABLE IV.1

REGRESSION OF ACTUAL HEAT RATES ON PREDICTED HEAT RATES

Variable	Coefficient	Standard Error
Constant	3519.6294	1083.4839
Actual Heat Rate	0.6368	0.1048+

R^2 = .551

+ = Significant at 99.5 percent (two-tailed)

TABLE IV.2

REGRESSION OF ACTUAL AVERAGE COST ON PREDICTED AVERAGE COST

Variable	Coefficient	Standard Error
Constant	3.4023	1.1770
Actual Average Cost	0.6737	0.0721+

R^2 = .744

+ = Significant at 99.5 percent

While the model generally predicts lower heat rates and average costs than we observe, it still predicts quite well. Perfect prediction by the model would require that the coefficients on actual heat rates and average costs equal one. A t-test would lead us to reject the hypothesis that either is significantly different from one at the 80 percent level. But in spite of the model's achievements some explanation is in order for the lower predicted average costs predicted by the model. Certainly, if expected price ratios or availability rates were other than what we have assumed, cost minimizing heat rates and <u>ex post</u> average costs would be different. If, for instance, lower relative fuel prices had been expected when the unit was designed then cost minimizing heat rates would have been higher.

Another possible reason for our underprediction of average costs relates to our construction of expected output. With the exception of four units in our sample the expected output we have assigned to these units is greater than what actually occurred.[2] This may have happened for three reasons. First, actual availability of the units may have been less than what the availability expectations we have used suggested. Since our sample is fairly small and expected availability rates were calculated using both baseload and nonbaseload units it is entirely possible that availability rates for our sample would be somewhat different than the published availability rates used to proxy expected availability.

Secondly, the definition of capacity we have used is the "net continuous plant capability when not limited by condenser." Two other candidates for capacity found in our plant data are the name-plate rating and the net continuous plant capability when limited by condenser water. The former, while used by many researchers, is not generally considered to be a good measure of expected plant output because, in practice, its connotation has been one of "general identification" and a manufacturers "performance guarantee" under specified operating conditions. The latter rating applies for those periods of the year when condensing water is in short supply. Since this is typically a small portion of the year this capacity rating would understate net capacity for most of the year. This leaves us with the capacity definition we have chosen. Though this is the best capacity definition available it will necessarily overstate output for those units which have small portions of the year when condensing water availability is a problem.[3]

Finally, we must acknowledge the assumption that all units are intended for a utilization rate of one. If this assumption does not hold in all cases or if one of the other two assumptions breaks down then our predicted output should be greater than actual output and predicted average costs should, consequently, be smaller. But in spite of all of the potential measurement problems mentioned here the model predicts costs and heat rates quite well.

Our next objective is to use the model to simulate cost behavior for changing relative factor prices and unit size so that we may develop an impression of how long-run average costs respond to changes in these variables.

4.2 SIMULATION RESULTS

Tables IV.3 through IV.18 give the results of the simulation exercise. For the simulations we first set the number of units equal to 1 and set the interest rate embedded in the service price of capital equal to 9 percent. Next, we varied the unit size and the fuel price and solved for the cost minimizing heat rates and the associated minimum average cost for each cell. Simulations were run for each of the four regions and for the four possible combinations of the coal type and cooling tower dummy.

In developing the simulations we first made an adjustment to the availability data. The availability rates provided by the Edison Electric Utility Institute are in a discrete form with all units of size 800 MW or greater assigned a single availability rate. In order to extrapolate to availability rates for units whose sizes are larger than 800 MW we regressed the availability rates on the log of the unit size at the midpoint of each of the size ranges. With a coefficient of -.10098 on the log of unit size this resulted in assigning slightly higher availability

rates to units around the 800 MW level, but slightly smaller availability rates to units larger than 1050 MW.[4] The results of the simulation are given below in Tables III.3 through III.18.

TABLE IV.3 MINIMUM AVERAGE COSTS AND COST MINIMIZING HEAT RATES FOR DIFFERENT FUEL PRICES ($/MMBTU) AND UNIT SIZES (mills/kWh and Btu/kWh)

P_f / MW	.3	.5	.7	.9	1.1	1.3	1.5
150	8.094 10868	10.26 10807	12.42 10754	14.56 10704	16.70 10652	18.829 10607	20.946 10568
250	8.271 10798	10.42 10738	12.57 10686	14.70 10638	16.82 10597	18.939 10546	21.045 10501
350	8.612 10749	10.75 10701	12.89 10653	15.01 10608	17.13 10568	19.243 10521	21.343 10480
450	8.774 10717	10.91 10673	13.04 10615	15.16 10585	17.27 10538	19.3748 10493	21.470 10453
550	8.907 10691	11.04 10638	13.16 10599	15.28 10551	17.38 10515	19.482 10467	21.574 10437
650	9.021 10670	11.15 10608	13.27 10577	15.38 10530	17.48 10487	19.576 10452	21.663 10419
750	9.119 10641	11.24 10600	13.36 10551	15.46 10570	17.56 10477	19.657 10436	21.813 10399
850	9.208 10623	11.33 10575	13.44 10543	15.54 10501	17.64 10466	19.731 10425	21.813 10388
950	9.288 10607	11.40 10573	13.51 10523	15.61 10491	17.71 10450	19.797 10413	21.876 10380
1050	9.362 10599	11.47 10551	13.58 10511	15.68 10477	17.77 10442	19.857 10399	21.935 10368
1150	9.429 10585	11.54 10548	13.64 10501	15.74 10471	17.83 10426	19.913 10394	21.989 10363
1250	9.491 10575	11.60 10528	13.70 10487	15.79 10452	17.88 10419	19.966 10384	22.040 10349

Region = Central and Southeast

Cooling Tower Dummy = 1

Fuel Type Dummy =1

Sample:

$\bar{k}$ = N.A.

$\bar{\alpha}$ = N.A.

TABLE IV.4 MINIMUM AVERAGE COSTS AND COST MINIMIZING HEAT RATES FOR DIFFERENT FUEL PRICES ($/MMBTU) AND UNIT SIZES (mills/kWh and Btu/kWh)

P_f / MW	.3	.5	.7	.9	1.1	1.3	1.5
150	8.116 10041	9.04 9973	11.03 9928	13.017 9888	14.99 9848	16.95 9806	18.913 9765
250	8.042 9971	8.97 9907	10.94 9868	12.916 9820	14.876 9777	16.83 9746	18.775 9712
350	8.207 9930	9.09 9868	11.060 9829	13.022 9785	14.975 9746	16.92 9714	18.845 9683
450	8.232 9898	9.10 9849	11.065 9798	13.022 9761	14.970 9721	16.911 9684	18.845 9656
550	8.251 9877	9.111 9812	11.069 9773	13.021 9737	14.965 9698	16.901 9665	18.832 9628
650	8.268 9854	9.118 9796	11.07 9758	13.021 9722	14.961 9685	16.894 9647	18.82 9616
750	8.281 9835	9.12 9779	11.076 9746	13.021 9699	14.957 9666	16.888 9629	18.811 9604
850	8.294 9819	9.13 9768	11.079 9726	13.021 9689	14.955 9656	16.883 9617	18.803 9585
950	8.305 9806	9.135 9750	11.082 9709	13.021 9681	14.953 9638	16.877 9606	18.796 9577
1050	8.314 9795	9.14 9746	11.085 9699	13.021 9665	14.951 9631	16.874 9604	18.790 9567
1150	8.325 9781	9.145 9730	11.087 9689	13.022 9651	14.949 9618	16.870 9585	18.785 9554
1250	8.333 9773	9.149 9722	11.089 9685	13.022 9647	14.948 9612	16.867 9582	18.779 9547

Region = Central and Southeast

Cooling Tower Dummy = 0

Fuel Type Dummy = 0

Sample:

$\bar{k}$ = 567

$\bar{\alpha}$ = 10,044

TABLE IV.5 MINIMUM AVERAGE COST AND COST MINIMIZING HEAT RATES FOR DIFFERENT FUEL PRICES ($/MMBTU) AND UNIT SIZES (mills/kWh and Btu/kWh)

P_f / MW	.3	.5	.7	.9	1.1	1.3	1.5
150	7.081 10849	10.12 10001	12.11 9959	14.10 9975	16.08 9890	18.061 9856	20.029 9829
250	7.216 10769	10.03 9939	12.01 9896	13.99 9860	15.96 9829	17.923 9799	19.879 9769
350	7.483 10730	10.19 9890	12.16 9856	14.13 9826	16.09 9798	18.051 9766	20.001 9734
450	7.609 10697	10.21 9862	12.17 9825	14.14 9795	16.09 9769	18.046 9737	19.991 9712
550	7.712 10673	10.22 9837	12.18 9806	14.14 9772	16.09 9742	18.042 9709	19.982 9684
650	7.801 10641	10.23 9815	12.19 9785	14.15 9754	16.09 9726	18.392 9694	19.975 9667
750	7.877 10623	10.24 9797	12.20 9766	14.15 9737	16.09 9712	18.036 9682	19.969 9656
850	7.947 10608	10.25 9785	12.20 9754	14.15 9776	16.09 9693	18.034 9665	19.965 9636
950	8.008 10597	10.26 9773	12.21 9746	14.16 9709	16.09 9685	18.032 9656	19.960 9627
1050	8.006 10585	10.27 9763	12.22 9729	14.16 9698	16.10 9667	18.031 9636	19.956 9616
1150	8.118 10568	10.27 9746	12.22 9722	14.16 9689	16.10 9662	18.030 9629	19.954 9606
1250	8.167 10551	10.28 9746	12.22 9709	14.17 9677	16.10 9655	18.029 9622	19.951 9604

Region = Central and Southeast

Cooling Tower Dummy = 1

Fuel Type Dummy = 0

Sample:

$\bar{k}$ = 730

$\hat{\alpha}$ = 9,925

TABLE IV.6 MINIMUM AVERAGE COST AND COST MINIMIZING HEAT RATES FOR DIFFERENT FUEL PRICES ($/MMBTU) AND UNIT SIZES (mills/kWh and Btu/kWh)

P_f / MW	.3	.5	.7	.9	1.1	1.3	1.5
150	7.046 10023	9.2437 10781	11.39 10708	13.53 10645	15.65 10587	17.764 10538	19.865 10486
250	6.984 9947	9.364 10704	11.49 10641	13.62 10585	15.73 10528	17.835 10483	19.926 10435
350	7.112 9920	9.622 10673	11.75 10607	13.86 10551	15.97 10504	18.068 10452	20.154 10409
450	7.129 9882	9.742 10631	11.86 10585	13.97 10523	16.07 10477	18.165 10425	20.246 10389
550	7.143 9862	9.839 10607	11.95 10551	14.06 10504	16.15 10452	18.245 10408	20.322 10368
650	7.155 9837	9.924 10587	12.03 10538	14.14 10487	16.23 10437	18.314 10394	20.388 10349
750	7.164 9820	9.99 10575	12.10 10517	14.20 10469	16.29 10429	18.374 10380	20.446 10337
850	7.173 9806	10.06 10551	12.17 10504	14.26 10452	16.35 10409	18.428 10368	20.497 10326
950	7.181 9796	10.12 10543	12.22 10486	14.31 10443	16.40 10404	18.477 10351	20.545 10310
1050	7.188 9779	10.17 10523	12.27 10479	14.36 10435	16.45 10385	18.523 10342	20.588 10307
1150	7.195 9765	10.22 10520	12.32 10471	14.41 10425	16.49 10380	18.565 10334	20.628 10293
1250	7.202 9763	10.27 10504	12.31 10451	14.45 10407	16.53 10368	18.604 10323	20.666 10290

Region = Central and Southeast

Cooling Tower Dummy = 0

Fuel Type Dummy = 1

Sample:

$\bar{k}$ = 707

$\bar{\alpha}$ = 10,448

TABLE IV.7 MINIMUM AVERAGE COST AND COST MINIMIZING HEAT RATES FOR DIFFERENT FUEL PRICES ($/MMBTU) AND UNIT SIZES (mills/kWh and Btu/kWh)

P_f / MW	.3	.5	.7	.9	1.1	1.3
150	8.6119	10.783	12.94	15.094	13.243	19.367
	10873	10823	10781	10724	10681	10638
250	8.810	10.966	13.112	15.250	17.377	19.497
	10802	10760	10704	10661	10615	10585
350	9.189	11.336	13.474	15.604	17.725	19.838
	10754	10718	10673	10624	10587	10546
450	9.3705	11.510	13.641	15.765	17.880	19.987
	10725	10678	10632	10599	10555	10513
550	9.52	11.652	13.778	15.896	18.007	20.11
	10696	10648	10607	10575	10530	10501
650	9.645	11.77	13.896	16.010	18.117	20.216
	10664	10627	10587	10559	10511	10484
750	9.755	11.880	13.999	16.109	18.212	20.308
	10653	10607	10575	10530	10501	10466
850	9.854	11.976	14.091	16.198	18.298	20.39
	10627	10597	10551	10517	10480	10445
950	9.942	12.062	14.17	16.278	18.375	20.466
	10615	10585	10543	10504	10469	10437
1050	10.024	12.14	14.250	16.352	18.446	20.534
	10600	10568	10523	10487	10461	10425
1150	10.099	12.213	14.320	16.420	18.574	20.598
	10587	10559	10520	10475	10450	10418
1250	10.169	12.281	14.38	16.483	18.574	20.660
	10585	10543	10504	10467	10437	10401

Region = West

Cooling Tower Dummy = 1

Fuel Type Dummy = 1

Sample:

$\bar{k}$ = 458

$\bar{\alpha}$ = 10,620

TABLE IV.8 MINIMUM AVERAGE COST AND COST MINIMIZING HEAT RATES FOR DIFFERENT FUEL PRICES ($/MMBTU) AND UNIT SIZES
(mills/kWh and Btu/kWh)

P_F MW	.3	.5	.7	.9	1.1	1.3
150	7.48	9.481	11.473	13.458	15.435	17.404
	10030	9984	9940	9902	9868	9831
250	7.412	9.401	11.381	13.352	15.317	17.381
	9964	9913	9875	9835	9799	9766
350	7.555	9.535	11.508	13.472	15.431	17.381
	9912	9879	9849	9806	9764	9737
450	7.575	9.550	11.516	13.475	15.427	17.365
	9882	9849	9810	9777	9746	9712
550	7.592	9.561	11.522	13.476	15.427	17.373
	9867	9826	9785	9754	9722	9684
650	7.605	9.570	11.528	13.478	15.423	17.360
	9843	9806	9764	9734	9699	9665
750	7.616	9.578	11.532	13.479	15.420	17.354
	9826	9789	9750	9722	9684	9656
850	7.626	9.585	11.537	13.481	15.419	17.351
	9810	9173	9746	9701	9671	9645
950	7.635	9.592	11.541	13.482	15.418	17.347
	9798	9746	9715	9685	9649	9617
1050	7.644	9.598	11.544	13.484	15.417	17.344
	9785	9746	9715	9685	9649	9617
1150	7.652	9.604	11.548	13.486	15.417	17.341
	9772	9746	9702	9667	9635	9606
1250	7.659	9.609	11.551	13.487	15.417	17.339
	9768	9730	9693	9662	9632	9604

Region = West

Cooling Tower Dummy = 0

Fuel Type Dummy = 0

Sample:

$\overline{k}$ = N.A.

$\overline{\alpha}$ = N.A.

TABLE IV.9 MINIMUM AVERAGE COST AND COST MINIMIZING HEAT RATES FOR DIFFERENT FUEL PRICES ($/MMBTU) AND UNIT SIZES (mills/kWh and Btu/kWh)

P_f / MW	.3	.5	.7	.9	1.1	1.3
150	8.663 10047	10.668 10011	12.666 9973	14.653 9943	16.61 9911	18.622 9875
250	8.58 9973	10.575 9941	12.561 9707	14.539 9877	16.511 9848	18.478 9812
350	8.767 9939	10.751 9896	12.728 9869	14.701 9849	16.665 9810	18.624 9777
450	8.7967 9904	10.774 9869	12.745 9849	14.710 9810	16.669 9776	18.623 9754
550	8.818 9869	10.791 9845	12.757 9812	14.717 9785	16.672 9761	18.622 9732
650	8.370 9858	10.805 9826	12.768 9796	14.725 9766	16.675 9746	18.620 9709
750	8.852 9837	10.82 9810	12.777 9779	14.730 9748	16.677 9726	18.619 9696
850	8.675 9826	10.830 9799	12.786 9768	14.736 9737	16.68 9710	18.619 9685
950	8.88 9813	10.839 9779	12.792 9750	14.740 9726	16.682 9695	18.619 9667
1050	8.89 9797	10.848 9766	12.799 9746	14.744 9709	16.684 9684	18.620 9662
1150	8.902 9785	10.857 9759	12.806 9730	14.749 9699	16.687 9681	18.620 9652
1250	8.912 9777	10.864 9746	12.812 9722	41.753 9689	16.689 9666	18.620 9638

Region = West

Cooling Tower Dummy = 1

Fuel Type Dummy = 0

Sample:

$\bar{k}$ = 582

$\bar{\alpha}$ = 10,087

TABLE IV.10 MINIMUM AVERAGE COST AND COST MINIMIZING HEAT RATES FOR DIFFERENT FUEL PRICES ($/MMBTU) AND UNIT SIZES

(mills/kWh and Btu/kWh)

P_f / MW	.3	.5	.7	.9	1.1	1.3
150	7.491 10857	9.657 10793	11.804 10732	13.949 10676	16.08 10615	18.197 10570
250	7.643 10778	9.7941 10725	11.933 10673	14.061 10603	16.177 10563	18.284 10515
350	7.939 10742	10.08 10681	12.213 10627	14.334 10585	16.444 10528	18.546 10486
450	8.080 10704	10.216 0648	12.341 10600	14.456 10544	16.561 10504	18.866 10462
550	8.196 10679	10.325 10619	12.445 10572	14.555 10523	16.656 10475	18.748 10443
650	8.295 10655	10.420 10602	12.536 10551	14.642 10502	16.738 10466	18.827 10425
750	8.380 10630	10.56 10585	12.614 10538	14.716 10486	16.810 10450	18.895 10401
850	8.457 10615	10.576 10573	12.684 10521	14.784 10477	16.875 10435	18.957 10394
950	8.526 10600	10.64 10551	12.748 10502	14.845 10466	16.933 10429	19.01 10380
1050	8.590 10587	10.702 10542	12.806 10493	14.901 10450	16.987 10408	19.065 10378
1150	8.649 10574	10.759 10528	12.86 10480	14.953 10445	17.037 10399	19.113 10359
1250	8.703 10568	10.811 10517	12.910 10471	15.00 10435	17.08 10392	19.157 10351

Region = West

Cooling Tower Dummy = 0

Fuel Type Dummy = 1

Sample:

$\bar{k}$ = 415

$\bar{\alpha}$ = 11,771

TABLE IV.11 MINIMUM AVERAGE COST AND COST MINIMIZING HEAT RATES FOR DIFFERENT FUEL PRICES ($/MMBTU) AND UNIT SIZES (Btu/kWh and mills/kWh)

P_f / MW	.3	.5	.7	.9	1.1	1.3
150	10.698 10965	12.875 10863	15.045 10826	17.206 10789	19.362 10751	21.509 10722
250	10.984 10826	13.145 10786	15.300 10751	17.447 10717	19.588 10691	21.723 10655
350	11.516 10781	13.668 10744	15.814 10717	17.953 10686	20.08 10653	22.213 10615
450	11.772 10742	13.917 10707	10.055 10678	18.188 10645	20.315 10607	22.435 10587
550	11.981 10717	14.120 10686	16.252 10648	18.380 10620	20.501 10597	22.617 10568
650	12.160 10689	14.295 10652	16.423 10627	18.545 10600	20.663 10575	22.77 10548
750	12.3159 10673	14.44 10632	16.570 10607	18.689 10575	20.803 10551	22.911 10523
850	12.455 10645	14.582 10615	16.703 10587	18.819 10568	20.929 10537	23.034 10515
950	12.581 10627	14.704 10602	16.823 10584	18.935 10546	21.04 10522	23.144 10498
1050	12.696 10608	14.816 10583	16.932 10568	19.041 10537	21.1469 10515	23.246 10491
1150	12.802 10602	14.92 10585	17.033 10559	19.140 10523	21.243 10500	23.34 10477
1250	12.900 10597	15.016 10568	17.126 10543	19.232 10511	21.332 10486	23.43 10471

Region = Northeast

Cooling Tower Dummy = 1

Fuel Type Dummy = 1

Sample:

$\bar{k}$ = N.A.

$\bar{\alpha}$ = N.A.

TABLE IV.12 MINIMUM AVERAGE COST AND COST MINIMIZING HEAT RATES FOR DIFFERENT FUEL PRICES ($/MMBTU) AND UNIT SIZES (mills/kWh and Btu/kWh)

P_f / MW	.3	.5	.7	.9	1.1	1.3
150	9.22 10052	11.230 10015	13.230 9987	15.224 9954	17.211 9925	19.195 9896
250	9.138 9981	11.132 9951	13.119 9913	15.099 9892	17.075 9860	19.044 9833
350	9.342 9938	11.327 9911	13.306 9879	15.280 9852	17.247 9826	19.210 9798
450	9.375 9907	11.354 9875	13.326 9845	15.294 9825	17.256 9799	19.213 9777
550	9.399 9882	11.373 9851	13.341 9826	15.303 9798	17.260 9773	19.213 9750
650	9.420 9858	11.390 9832	13.354 9806	15.313 9779	17.266 9755	19.215 9730
750	9.438 9841	11.405 9812	13.365 9785	15.320 9766	17.270 9737	19.215 9709
850	9.455 9832	11.418 9797	13.375 9773	15.327 9746	17.275 9721	19.217 9698
950	9.469 9810	11.429 9785	13.385 9763	15.334 9737	17.278 9709	19.219 9684
1050	9.483 9789	11.439 9767	13.392 9737	15.339 9709	17.282 9689	19.220 9665
1150	9.495 9789	11.449 9767	13.401 9737	15.345 9709	17.286 9689	19.221 9665
1250	9.505 9779	11.458 9755	13.408 9729	15.351 9701	17.289 9682	19.223 9661

Region = Northeast

Cooling Tower Dummy = 0

Fuel Type Dummy = 0

Sample:

$\bar{k}$ = N.A.

$\bar{\alpha}$ = N.A.

TABLE IV.13 MINIMUM AVERAGE COST AND COST MINIMIZING HEAT RATES FOR DIFFERENT FUEL PRICES ($/MMBTU) AND UNIT SIZES (mills/kWh and Btu/kWh)

P_f / MW	.3	.5	.7	.9	1.1	1.3
150	10.868 10058	12.878 10032	14.882 10005	16.881 9984	18.875 9959	20.864 9938
250	10.766 9992	12.762 9958	14.753 9943	16.739 9913	18.720 9896	20.695 9868
350	11.028 9950	13.014 9926	14.997 9896	16.976 9875	18.949 9863	20.918 9835
450	11.071 9913	13.052 9888	15.028 9869	17.000 9854	18.968 9826	20.931 9806
550	11.104 9890	13.080 9867	15.051 9845	17.019 9826	18.994 9799	20.940 9777
650	11.132 9877	13.1043 9845	15.072 9826	17.035 9805	18.994 9777	20.949 9766
750	11.156 9851	13.124 9829	15.089 9810	17.048 9784	19.004 9766	20.955 9746
850	11.178 9835	13.143 9810	15.104 9795	17.061 9773	19.014 9759	20.963 9732
950	11.197 9826	13.161 9799	15.118 9779	17.072 9761	19.022 9746	20.968 9722
1050	11.215 9813	13.175 9785	15.131 9766	18.082 9750	19.031 9734	20.975 9711
1150	11.232 9805	13.189 9779	15.1438 9759	17.093 9737	19.038 9718	20.979 9695
1250	11.246 9789	13.202 9766	15.154 9750	17.102 9734	19.04 9711	20.984 9689

Region = Northeast

Cooling Tower Dummy = 1

Fuel Type Dummy = 0

Sample:

$\bar{k}$ = 720

$\bar{\alpha}$ = 9,769

TABLE IV.14 MINIMUM AVERAGE COST AND COST MINIMIZING HEAT RATES FOR DIFFERENT FUEL PRICES ($/MMBTU) AND UNIT SIZES (mills/kWh and Btu/kWh)

P_f / MW	.3	.5	.7	.9	1.1	1.3
150	9.1426 10889	11.315 10846	13.479 10793	15.633 10745	17.778 10704	19.915 10671
250	9.3629 10807	11.521 10763	13.669 10725	15.810 10686	17.942 10638	20.066 10600
350	9.7806 10758	11.929 10725	14.069 10681	16.202 10643	18.327 10603	20.444 10575
450	9.9808 10730	12.123 10688	14.256 10653	16.3823 10607	18.501 10583	20.612 10543
550	10.144 10701	12.280 10663	14.408 10619	16.529 10587	18.644 10551	20.750 10517
650	10.284 10676	12.415 10632	14.539 10600	16.656 10567	18.766 10527	20.869 10500
750	10.406 10654	12.534 10607	14.653 10585	16.766 10546	18.873 10511	20.972 10480
850	10.515 10632	12.639 10600	14.756 10568	16.865 10528	18.968 10501	21.065 10469
950	10.614 10615	12.734 10587	14.848 10551	16.955 10517	19.055 10491	21.149 10453
1050	10.703 10608	12.821 10575	14.932 10538	17.036 10504	19.135 10477	21.227 10443
1150	10.786 10597	12.902 10570	15.011 10523	17.112 10493	19.208 10469	21.298 10435
1250	10.863 10575	12.976 10546	15.083 10517	17.183 10486	19.276 10455	21.365 10427

Region = Northeast

Cooling Tower Dummy = 0

Fuel Type Dummy = 1

Sample:

$\tilde{k}$ = N.A.

$\tilde{\alpha}$ = N.A.

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TABLE IV.15 MINIMUM AVERAGE COST AND COST MINIMIZING HEAT RATES FOR DIFFERENT FUEL PRICES ($/MMBTU) AND UNIT SIZES (mills/kwh and Btu/kWh)

P_F / MW	.3	.5	.7	.9	1.1	1.3
150	7.523 10865	9.683 10794	11.842 10735	13.982 10676	16.112 10619	18.231 10575
250	7.676 10778	9.828 10725	11.967 10673	14.094 10607	16.212 10570	18.319 10508
350	7.975 10742	10.118 10681	12.249 10627	14.370 10585	16.482 10527	18.583 10491
450	8.1177 10704	10.253 10648	12.378 10600	14.493 10551	16.599 10504	18.696 10466
550	8.234 10680	10.364 10622	12.484 10578	14.594 10528	16.695 10480	18.788 10436
650	8.334 10655	10.459 10603	12.575 10551	14.681 10508	16.778 10471	18.867 10428
750	8.419 10631	10.541 10585	12.653 10538	14.756 10487	16.850 10450	18.936 10408
850	8.4975 10615	10.616 10570	12.725 10524	14.825 10479	16.916 10435	18.999 10399
950	8.5673 10600	10.682 10551	12.789 10502	14.886 10471	16.974 10428	19.055 10384
1050	8.6313 10587	10.744 10543	12.847 10493	14.942 10450	17.028 10407	19.11 10373
1150	8.6904 10573	10.800 10528	12.902 10486	14.995 10443	17.079 10399	19.155 10371
1250	8.7453 10568	10.853 10517	12.952 10477	15.043 10435	17.126 10392	19.201 10352

Region = Gulf

Cooling Tower Dummy = 1

Fuel Type Dummy = 1

Sample:

$\bar{k}$ = 513

$\bar{\alpha}$ = 10,831

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TABLE IV.16 MINIMUM AVERAGE COST AND COST MINIMIZING HEAT RATES FOR DIFFERENT FUEL PRICES ($/MMBTU) AND UNIT SIZES (mills/kWh and Btu/kWh)

P_f / MW	.3	.5	.7	.9	1.1	1.3
150	6.569 10011	8.566 9959	10.55 9907	12.529 9860	14.497 9814	16.456 9773
250	6.512 9940	8.496 9890	10.470 9849	12.434 9796	14.389 9754	16.336 9709
350	6.623 9900	8.599 9857	10.566 9810	12.524 9769	14.447 9723	16.413 9685
450	6.638 9877	8.608 9826	10.568 9779	12.520 9737	14.464 9696	16.399 9663
550	6.649 9849	8.614 9799	10.569 9760	12.517 9714	14.456 9677	16.387 9636
650	6.658 9829	8.619 9777	10.572 9737	12.515 9696	14.451 9661	16.378 9619
750	6.666 9810	8.624 9769	10.573 9722	12.513 9680	14.445 9638	16.369 9606
850	6.674 9796	8.628 9748	10.575 9712	12.512 9667	14.442 9628	16.363 9590
950	6.680 9777	8.632 9738	10.576 9694	12.511 9658	14.438 9616	16.357 9584
1050	6.686 9773	8.636 9730	10.577 9685	12.510 9644	14.435 9606	16.352 9569
1150	6.692 9763	8.639 9712	10.578 9677	12.509 9630	14.432 9598	16.348 9561
1250	6.696 9748	8.643 9711	10.579 9663	12.508 9622	14.430 9587	16.344 9552

Region = Gulf

Cooling Tower Dummy = 0

Fuel Type Dummy = 0

Sample:

$\bar{k}$ = 577

$\bar{\alpha}$ = 9,871

TABLE IV.17 MINIMUM AVERAGE COST AND COST MINIMIZING HEAT RATES FOR DIFFERENT FUEL PRICES ($/MMBTU) AND UNIT SIZES (mills/kWh and Btu/kWh)

P_f / MW	.3	.5	.7	.9	1.1	1.3
150	7.513 10034	9.515 9985	11.51 9940	13.493 9900	15.469 9867	17.439 9833
250	7.446 9965	9.434 9513	11.414 9875	13.387 9849	15.351 9807	17.309 9764
350	7.590 9912	9.570 9878	11.543 9849	13.507 9804	15.465 9773	17.417 9737
450	7.611 9892	9.965 9854	11.551 9810	13.511 9777	15.463 9742	17.408 9708
550	7.627 9867	9.596 9826	11.557 9789	13.512 9755	15.461 9722	17.401 9689
650	7.640 9843	9.606 9806	11.564 9777	13.514 9737	15.458 9699	17.396 9667
750	7.651 9826	9.613 9789	11.568 9755	13.515 9722	15.456 9684	17.390 9651
850	7.662 9810	9.621 9773	11.573 9746	13.517 9706	15.456 9671	17.387 9636
950	7.672 9797	9.628 9763	11.577 9731	13.518 9690	15.454 9662	17.384 9632
1050	7.680 9785	9.634 9746	11.581 9712	13.520 9685	15.454 9652	17.381 9617
1150	7.688 9777	9.6397 9745	11.584 9702	13.522 9671	15.454 9645	17.378 9609
1250	7.695 9769	9.645 9729	11.588 9696	13.523 9662	15.453 9632	17.376 9604

Region = Gulf

Cooling Tower Dummy = 1

Fuel Type Dummy = 0

Sample:

$\overline{k}$ = N.A.

$\overline{\alpha}$ = N.A.

TABLE IV.18 MINIMUM AVERAGE COST AND COST MINIMIZING HEAT RATES FOR DIFFERENT FUEL PRICES ($/MMBTU) AND UNIT SIZES (mills/kWh and Btu/kWh)

P_f / MW	.3	.5	.7	.9	1.1	1.3
150	6.629 10836	8.788 10751	10.931 10686	13.060 10607	15.176 10545	17.280 10487
250	6.7457 10760	8.890 10691	11.021 10615	13.137 10551	15.241 0487	17.334 10437
350	6.9793 10723	9.116 10653	11.240 10585	13.349 10523	15.448 10471	17.536 10413
450	7.089 10681	9.219 10608	11.342 10551	13.441 10493	15.535 10445	17.618 10394
550	7.1795 10652	9.304 10597	11.416 10528	13.517 10477	15.606 10429	17.686 10377
650	7.256 10631	9.377 10575	11.485 10515	13.582 10457	15.668 10402	17.744 10356
750	7.323 10615	9.440 10551	11.545 10493	13.638 10445	15.721 10388	17.795 10342
850	7.384 10599	9.497 10537	11.599 10474	13.689 10426	15.771 10380	17.841 10330
950	7.4385 10575	9.548 10523	11.648 10471	13.736 10413	15.814 10368	17.883 10323
1050	7.4880 10570	9.596 10515	11.692 10453	13.778 10406	15.854 10352	17.921 10310
1150	7.534 10551	9.639 10501	11.734 10447	13.818 10399	15.89 10349	17.957 10306
1250	7.5765 10548	9.679 10491	11.772 10437	13.854 10389	15.927 10346	17.990 10297

Region = Gulf

Cooling Tower Dummy = 0

Fuel Type Dummy = 1

Sample:

$\bar{k}$ = 512

$\bar{\alpha}$ = 10,681

A general result is that cost minimizing heat rates fall with both relative fuel prices and with unit size in every case. That cost minimizing heat rates fall with fuel prices reflects the cost penalty associated with fuel inefficiency when relative fuel prices are higher. And that heat rates fall with unit size reflects the fact that fuel efficiency is relatively cheaper to achieve in larger units.

Throughout the simulations minimum average cost occurs at a small unit size. This minimum occurs at the 250 MW level for the units which use the higher coal heating values (DSL = 0) and at 150 MW for units which use lignite or subbituminous (DSL = 1). This seems plausible since the cost of additional efficiency is higher for units which use the lower heating value coal.

Generally, average costs moderately escalate after obtaining their minimum value.[5] There are exceptions to this, however. With the exception of the Northeast case, average costs trail off for higher relative fuel price-size combinations for the DSL = 0 units. That these average cost reductions are found in the DSL = 0 units is, again, related to the relatively smaller cost penalty associated with improving efficiency for these units. The reason that these scale economies occur only at higher prices is the same reason that average costs, in general, are insensitive to size at higher relative fuel prices. For fixed fuel prices, average fuel costs decline with size due to the increase in efficiency. Average plant costs generally rise, however,

because of declining availability. But at higher relative fuel prices, fuel costs become more important in determining average total costs, leading to the declining average costs found in these cases. That the same result does not obtain for the Northeast region results from the relatively large plant cost coefficient on the Northeast dummy variable.

Another general result is that for fixed size and relative fuel price the high coal heating value - no cooling tower case yields the smallest average cost and the lowest cost minimizing heat rates. The highest average cost and cost minimizing heat rates are found at the opposite extreme where DSL = 1 and a cooling tower is required. And, when compared to the lowest average cost case, the average cost effects of adding a cooling tower appear to be more expensive than using lower heating value coal with no cooling tower.

Looking now to specific region results the Central and Southeast region has the most units in our sample. Out of 16 units here 12 used the higher heat valued coal. Of these 12 only 2 units required cooling towers. The average size of these units is 594 MW and the average observed heat rate was 10,024. This average heat rate appears to be approximately 300 Btu/kWh greater than the cost minimizing heat rates shown in Table IV.4, the relevant one. Interestingly, with the exception of one 1300 MW unit which uses lignite, the three largest units in our sample lie in the declining average cost region of the lower righthand corner of Table IV.4. Further, consistent with the higher heat rates found in Table IV.6, the average observed heat rates for the 4 units which had DSL = 1 was 10448.

In the Western region, five out of seven of the units in our sample had DSL = 1 with only one of these units requiring a cooling tower, making Table IV.10 the relevant one for our purposes. Relative fuel prices for these units had a range of $0.30 - $0.70 per MMBtu and the average heat rate for these units was 10,850. Also, the low average unit size of 449 MW in this region is consistent with the low minimum average costs appearing in the upper left section of Table IV.10. The average heat rate for the two units which have DSL = 0 was 10087 and the average unit size was 582 MW; this is consistent with the slightly higher size level where minimum average costs occur in Table IV.9.

The region for which we have the fewest units in our sample is the Northeast region. Only two units in our sample were from this region and both had DSL = 0 and required cooling towers, making Table IV.13 the relevant table. The average fuel price for these two units was $1.17 per MMBtu and the average heat rate was 9,769 which is near the cost minimizing heat rates found in the table. The two unit sizes observed in this region were 615 and 825 MW.

In the Gulf region we have five out of seven units which had DSL = 1, two of these units requiring cooling towers. With fuel prices for these units ranging from $0.40 to $1.20 per MMBtu the average heat rate of 10,733 compares fa

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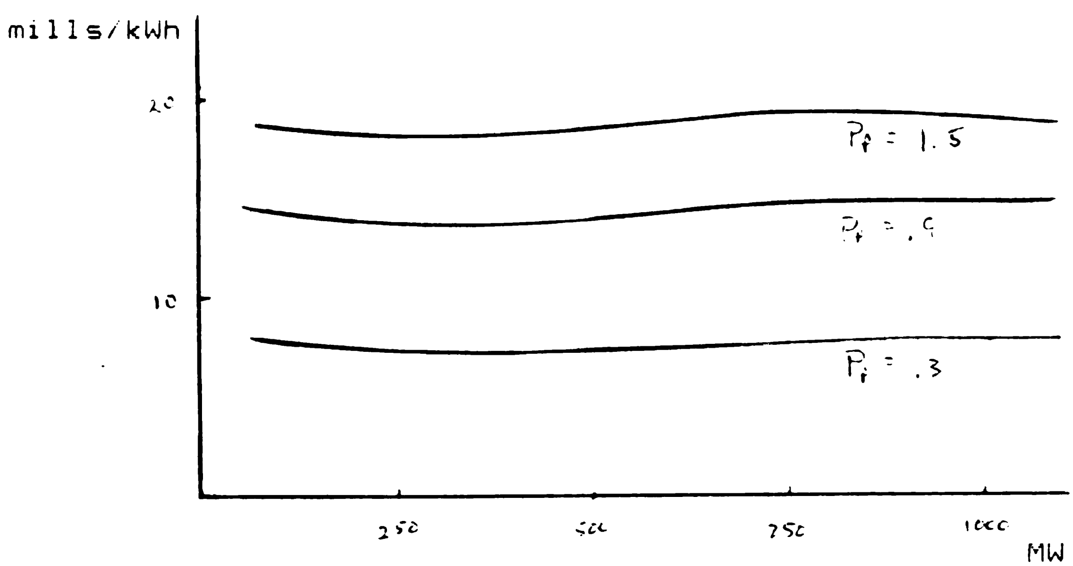
favorably with the cost minimizing heat rates found in Table IV.18. Over all groups this group has the second lowest average unit size of 509 which seems consistent with the low minimum efficient sizes found in the table.

Finally, we should note that the sensitivity of average costs to changes in output is visibly quite small in all of the cases. This is illustrated below in Figure IV.1 which graphs the average costs versus size figures from Table IV.4.The figures are representative of the largest group of units in our sample.

FIGURE IV.1 AVERAGE COSTS VERSUS UNIT SIZE



The illustration above bears out the calculated arc scale elasticities we have found. Focussing again on the cost figures in Table IV.4, we find that the arc elasticity of average cost with respect to output between 150 and 250

MW is -.02 for P_f = .3 and -.016 for P_f = 1.3. And between 1150 and 1250 MW this same elasticity is .0138 for P_f =.3 and -.0028 for P_f = 1.3.

The illustrations above point to the primary conclusion of this study: when one controls for the cost effects of declining unit availability, minimum efficient generating unit size is on the order of 150 to 250 MW. Moreover, average costs appear to be relatively insensitive to unit size beyond the predicted minimum average cost. That others have found the existence of scale economies is undoubtedly related to their failure to recognize the cost effects of plant availability.

The lack of scale economies demonstrated by this study also tends to confirm the results presented by Perl,[6] the only other study that explicitly considered the effects of equivalent availability. Both studies found that costs were relatively insensitive to size beyond a unit size of approximately 200 MW. However, the results of the present study are different in that we were able to identify the influence of regional and engineering characteristics on scale economies.

Summary

This chapter began with a discussion of the solution to the theoretical model developed in the first four sections of Chapter III. Adding fuel costs to the capital costs developed in the plant cost function, and using equation

III.6, we used a numerical search to solve for the cost minimizing level of plant efficiency and the associated average cost for each plant in our sample.

Next, we attempted to validate our model by comparing our predicted average costs and efficiency levels with the observed values. Regressing predicted heat rates and predicted average costs on their actual values, perfect prediction by the model would have required the slope estimates to equal one. Since a t-test would have led us to reject the hypothesis that the coefficient on either of the independent variables was significantly different from one we concluded that our estimated model provided a reasonable approximation to the underlying cost structure.

Satisfied with the performance of the model we next returned to the issue of scale economies. Noting early on that our model could not be solved to yield a parametric demonstration of scale economies we used the model to simulate minimum average costs for different plant sizes and relative factor prices. These average cost grids were calculated for each of the four geographical regions controlled for in our plant cost function and for the four possible combinations that the fuel quality and cooling tower dummies could take.

In sum, the simulation exercise leads us to the conclusion that when one controls for desired utilization minimum efficient plant scale is small. Moreover, due to declining availability with unit size, long-run average costs tend to be fairly insensitive to unit size. The results of the simulation exercise also lead us to believe that baseload plant level average costs depend, in part, on the quality of coal that is economically available to the plant and to the level of construction expenditures required in providing a condensing water supply to the plant. But even when the plant is opportunely co-located with high heat value coal and abundant condensing water, the cost advantages of large unit size appear to be insignificant.

ENDNOTES: CHAPTER IV

1
We must resort to a numerical solution because equation III.5 cannot be solved for the cost minimizing level of unit efficiency. But while we must resort to a numerical solution, uniqueness is not a concern because of the assumed strict convexity of the plant cost function with respect to the heat rate.

2
The reader will recall that the expected output used in the model is given by $\hat{Q}$ = 8760ka(k).

3
For a complete discussion of the different capacity definitions see U.S. Federal Power Commission, Steam Electric Plant Construction Cost and Annual Production Expenses - 1956, Washington, D.C., Government Printing Office, 1957, pp. X - XXI.

4
For the observation in the 800 MW and above group we used 1050 MW. The estimated equation was:

Availability = 1.36378 - .10098 lnk.

5
The average cost increases and decreases found in the tables are generally quite small and many fall within the mean squared error of our forecast of predicted average costs on observed average costs. (The largest increase in average costs was found in Table IV.11 where average costs increased by approximately 2.2 mills/kWh over the range of unit sizes.) However, as the MSE was fairly small (.2677) we would have to conclude that diseconomies are conceivable under certain conditions. We also calculated the MSE for plant sizes above and below the mean plant size (576 MW) separately. The MSE for plant sizes above the mean was 1.12 and the MSE for plant sizes below the mean plant size was 0.16. Consequently, we have relatively more faith on predicted average cost behavior in the region of smaller sized units.

6
Perl, op. cit.

CHAPTER V

CONCLUSIONS FROM THIS STUDY

5.1 Summary of Thesis

This study has addressed the problem of investigating steam-electric, plant level scale economies when one explicitly considers the separate cost effects of desired utilization and plant availability. At the outset it was noted that regulatory agencies, to the extent they oversee the plant sizing decision, should have an interest in the independent cost effects of utilization desirability and plant availability. It was also pointed out that previous studies have either been flawed in their consideration of utilization, or they have ignored the distinction entirely.

In motivating our analysis we noted that since one frequently observes the same output being produced with different sized generating units, an assumption of full or constant utilization across all generating units is particularly inappropriate for this industry. Further, we noted that, with one exception, all previous researchers attempted to capture the utilization effects by using the ex post plant factor. Our point of departure with the existing literature involved an examination of the components of <u>ex post</u> utilization. Because of declining unit availability with size, larger units will tend to exhibit lower <u>ex post</u> utilization rates and, hence, higher average capacity costs, holding constant desired utilization. Further, because of the firms requirement to serve a peaked load schedule throughout the period, plants are rationally designed with different desired utilization rates in mind. *Ex post* utilization rates would, therefore, depend as well on the units' desired utilization. It was the distinction between desirability and availability, and the likely separate influences on long-run average costs these variables would have, that provided our motivation to reexamine scale economies in this industry.

Regarding the methodology used to test hypotheses concerning scale economies, a non-traditional engineering-economics approach was developed. It was pointed out that the traditional neoclassical production function approach to measuring scale economies was designed for general applicability across different technologies. In contrast, the engineering-economics approach uses technology specific engineering information that allows one to analytically examine the engineering factors that influence the economic characteristics of the technology. It was further pointed out that the added dimension of information provided by this approach should be of interest to the regulators of this industry.

As an extension of arguments set out above we next developed an *ex ante*, long - run fuel and capital cost model. The model was constructed to allow us to consider both availability and capital nonhomogeneity explicitly. The model assumed an exogenously given baseload (desired utilization of one) and a production technology wherein only fuel and capital are combined to produce electricity. Given the plant cost function, which was presumed to be an equipment manufacturer's pricing list for various combinations of capacity and efficiency, and given expected fuel prices and expected unit availability, the problem for the firm was to select an efficiency level which would minimize the expected average cost of servicing the exogenously given baseload.

This model was estimated over 32 newly constructed coal-fired units which began operation between 1972 and 1978. We pointed out that while the identification of baseload units is difficult, ex ante, our selection of only new coal fired units was likely to be a good approximation because of the relatively low short-run marginal cost exhibited for coal plants as compared to oil or gas plants. The final result of the model was a search procedure which predicted the cost minimizing efficiency level and minimum average cost for each unit in our sample.

While the model predicted actual heat rates and average costs well, unfortunately, it could not be manipulated to yield parameter estimates of scale economies. To examine the sensitivity of long-run average costs to different unit sizes we therefore used the model to simulate heat rates and average costs for different units sizes and relative factor prices.

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heat value coal and abundant condensing water supplies. But even in these cases, the cost advantages of large unit size are small. For those plants which are not availed of high quality coal and large quantities of water, cost disadvantages accrue with size for all relative fuel prices investigated.

5.2 Implications of the Results

Implied by our results is a prescription for regulatory agencies to, in most instances, discourage large unit size choices. Focussing only on the combined cost effects of availability and size, we found that the benefits of enhanced efficiency in large units was more than offset by availability problems under most circumstances. For the cases identified in Chapter IV where long-run average costs were relatively flat our suggestion would be neither to discourage or encourage a particular unit size over the range of sizes considered in our sample.

Had we extended our scope to include the unit size/availability cost effects on overall firm or system reliability, and hence the system reliability affects on plant level scale economies, we suspect that large unit choices would have proven even less beneficious than we have found. While we have no conclusions as regards firm level influences on plant choices this is certainly fertile ground for future study.

We have not focused on the mechanism regulators might use to discourage or encourage particular size choices but there are several tentative choices which have potential. One suggestion would be to use the traditional rate proceeding. Here a commission could strictly adhere to the notion of 'useful' capacity and exclude a portion of the book value of large units from the rate base based on the unit's actual or expected availability. Alternatively, one might tie the allowed rate of return to the unit's availability. Both of these alternatives would have merit in that the true culprit, unavailability, would be the target, and not size. As an aside, some states (Michigan for example) already have programs of this nature in place.

As regards the unit choices reflected in our sample, our results suggest that, to the extent decisions were indeed based on minimizing long-run average costs, the utilities may have been disappointed in *ex post* average costs. The unit size decision may, in fact, depend on several factors, some of which were outside our scope. In addition to the factors we have addressed, the unit size decision may depend, *inter alia*, on Averch-Johnson motivations, plant siting constraints, and firm specific considerations. Our model was incomplete with respect to these other factors and the implications we derive must be considered tentative to the extent these other factors are important. However, while these other factors may influence

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5.3 Limitiations of the Study and Suggestions for Further Research

Our conclusions are conditioned on several limitations of scope and in this subsection we will attempt to identify the more important limitations placed on the analysis. First, isolating the independent cost effects of availability required the exclusion of a large number of generating units. This resulted from our inability to derive a proxy for desired utilization for units that were not intended for baseload duty. Availability presumably influences the shape of the LRAC for cycling and near baseload units, but we could not develop a satisfactory proxy for desired utilization for these units. Consequently, a large number of units, for which we had good data on availability and other characteristics, were screened from the analysis.

A by-product of the inability to model desired utilization was our need to focus on new coal-fired generating plants. While our assumption that these units were intended for baseload duty may be satisfactory it is also the case that some gas and oil fired units may be intended as baseload units. However, the extent to which gas and oil units may be baseloaded depends on such factors as the size of the firm or system and the firms relative proximity to gas, oil and coal producing areas. Since these factors are likely to combine in a complex way in determining desired utilization for oil and gas-fired units we made a simplifying assumption which excluded them.

A final limitation on our scope was the exclusion of nuclear units. While nuclear units would certainly be considered baseload generating units we chose not to consider these units primarily because of their relative complexity and uncertain and changing technology. Plant costs for nuclear plants are likely to be controlled by substantially different forces than fossil units are. Because nuclear fuel costs are about 25 percent of coal fuel costs, unit efficiency is less of a concern. In addition, plant investment costs are likely to be relatively more influenced by the credentials of contractors and transient safety regulations. In short, we were less confident in our ability to develop a nuclear plant cost model that would adequately describe plant costs while maintaining a reasonable number of degrees of freedom.

Suggestions for Further Research

It is typically the case that the limitations of one's study suggest the direction for future research in elaborating on the research topic; and so it is in this case. Desired utilization and plant availability both exert economic influences on the plant size and plant efficiency decision. While the attempt made in this study to capture the influence of desirability was useful it is also far from complete. One suggestion for future research would then be to develop a more complete understanding of desired utilization for generating plants.

Another area of research that would be fruitful would be to investigate the impact of firm or system characteristics on the plant choice decision. We noted in our introduction that the unit size decision influences the reserve requirements for the firm when trying to meet some level of overall system reliability target. This suggests that plant scale economies may well be paritially controlled by firm level information. An understanding these system level influences would thus improve our knowledge of the plant choice decision.

In conclusion, this study has demonstrated that when one controls for the independent effects of declining plant availability and desired utilization, minimum efficient unit scale is typically in the vicinity of 250 MW. Although these results are conditioned on our exclusive consideration of baseload coal units they are in stark contrast to the results found in studies which have ignored the distinction between availability and desired utilization. That this distinction has reversed the common perception of scale economies for this technology suggests that other industries, to the extent they may be subject to similar characteristics, may need to be reexamined in this light.

APPENDIX

Appendix A

Data Used in this Study

The information used in this study came from two primay sources. The bulk of this data was obtained from annual supplements to Steam-Electric Plant Construction Cost and Annual Production Expenses, which is published annually by the Federal Power Commission.[1] The publication includes plant specific information on plant size, number of generating units in the plants, heat rates, investment and annual operating costs, output, coal quality, the use of cooling towers, and other pertinent data. In addition, information on equipment availability was obtained from the Edison Electric Institute's Report on Equipment Availability for the Ten-Year Period: 1967 - 1976. Below we describe each of the variables along with a description of special variable constructions made for the analysis.

Equivalent Availability Rates

The availability rates used in this study are the equivalent availability rates for fossil-fired units reported in the source cited above. While these availability statistics are appropriate for the vintage of coal units considered in this sample, a problem is that these availability rates cover all fossil-fired units and not just

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[1] See our footnote III.16.

coal-fired units. This is not likely to seriously bias our results, however, because the availability rates for all fossil-fired units and the availability rates for coal-fired units are quite similar.

Equipment availability rates for more recent vintages have been given for coal units in addition to the "all-fossil" category. These statistics show that while the availability rates for coal-fired units are somewhat lower than for the more inclusive fossil-fired category, the rate of reduction in availability with size is approximately the same. To see this, Table A-1 shows (1) equivalent availability rates for coal-fired units over the 1972-1981 timeframe, and (2) equivalent availability rates for all fossil-fired units over the 1972-1981 time period.

TABLE A-1

COMPARATIVE EQUIVALENT AVAILABILITY RATES
FOR THE PERIOD 1972-1981

SIZE CLASS	(1) COAL UNITS	(2) ALL FOSSIL UNITS
100-199 MW	81.89	82.58
200-299 MW	79.06	79.75
300-399 MW	70.33	73.51
400-599 MW	68.87	72.21
600-799 MW	69.14	70.11
800 MW and above	69.16	69.05

The availability rates in Table A-1 demonstrate that the availability rate for coal units is moderately less than that for all fossil-fired units. _Ceteris paribus_, if this holds true for the vintage of units considered in our sample our results should be biased in favor of finding scale economies. That we do not generally find scale economies with this bias in place seems only to support the conclusions of this study.

Heat Rate

Once generating plants are put into operation it may take several years to "work all the kinks out" and obtain the efficiency levels intended when the unit is designed. Pipes and turbine shafts and other equipment must adjust to the extreme pressure and temperature changes; unanticipated weak spots in the process must be strengthened. As a consequence, observed heat rates in the first year of operation are apt to be poor indicators of the fuel efficiency the plant was designed for and is capable of. To circumvent this problem we took the average heat rate over the first three full years of the plants life as the measure of plant efficiency.

Average Cost

To maintain consistency with our heat rate observation we made similar adjustments in the values that make up observed average fuel costs. Both output and total fuel costs were averaged over the same time frame as the heat rate observations. While averaging output over a time frame of this length is straight forward, fuel costs are subject to price level changes. As long-term coal contracts are typically indexed to account for rising wages and operating costs we first adjusted all observed fuel costs using the Wholesale Price Index for coal before calculating observed average costs. All production costs were adjusted to a 1975 constant dollar basis before averaging.

Investment Costs

Given in our data source are per kilowatt investment costs for equipment, structures, and land. As structures and land investment costs are investments that are determined by specific site conditions we considered only equipment costs. As we noted in Chapter III, these costs were then adjusted to constant 1975 dollars using the Handy Whitman Index of Public Utility Construction Costs.[2]

Cost of Capital

For the cost of using capital we assumed a standard 30-year life and straight line depreciation. For the cost of money capital we used the interest rate observed for long-term debt on the issue immediately preceding construction of the plant, on a specific utility basis. These data were obtained from Moody's Public Utility Manual, various years.

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[2] Supra, note III.18.

Table A-2

List of Plants

Plant Code	Utility	Plant
1	Louisville Gas and Electric	Mill Creek
2	Monongahela Power Co.	Harrison
3	Pacific Power and Light Co.	Centralia
4	Public Service Co. of Colorado	Comanche
5	Lansing Board of Water and Lt.	Erickson
6	Columbus and So. Ohio Elec.	Conesville
7	Tennessee Valley Authority	Cumberland
8	Alabama Power Company	Gaston
9	Salt River Project	Navajo
10	Kentucky Utilities Company	Ghent
11	Ohio Electric Company	Gavin
12	Dallas Power and Light Co.	Monticello
13	Pacific Power and Light Co.	Jim Bridger
14	Utah Power and Light Co.	Huntington
15	Cincinnati Gas and Electric	Miami Fort
16	Otter Tail Power Co.	Big Stone
17	Wisconsin Power and Light Co.	Columbia
18	Public Service Co. of Indiana	Gibson
19	Iowa Public Service Co.	Neal
20	Montana Power Company	Colstrip
21	Southwest Public Service Co.	Harrington
22	Northern States Power Co.	Sherburne Cty.
23	Pennsylvania Power Co.	Mansfield
24	Central Illinois Light Co.	Duck Creek
25	San Antonio Public Service Co.	J.T. Deely
26	Union Electric Co.	Rush Island
27	Central Illinois P.S. Co.	Newton
28	Kansas Power and Light Co.	Jeffery
29	Iowa Power and Light Co.	Council Bluffs
30	Southwestern Electric Power	Flint Creek
31	Alabama Power Co.	Miller
32	Southwestern Electric Power	Welsh

Table A-3

List of Data

Plant Code	Unit Size (MW)	Heat Rate (Btu/kWh)	Coal Type Dummy	Cooling Tower Dummy
1	336	10020	0	0
2	615	9572	0	1
3	633.5	10409	1	1
4	330	10343	1	1
5	153.5	10143	0	0
6	800	10082	0	1
7	1158	10123	0	0
8	865.4	9804	0	0
9	750	10234	0	1
10	525	10468	0	0
11	1300	10144	1	0
12	575	10799	1	0
13	508.5	10473	1	1
14	415	9940	0	1
15	500	10123	0	0
16	415	11771	1	0
17	516.3	10701	1	0
18	636	9906	0	0
19	525	9561	0	0
20	358.3	11255	1	1
21	343	10264	1	1
22	707.5	10387	1	0
23	825	9966	0	1
24	395	10341	0	0
25	418	10622	1	0
26	577	9871	0	0
27	579	9956	0	0
28	684	11399	1	1
29	303.6	10560	1	0
30	528	10725	1	0
31	660	9769	0	1
32	528	10580	1	0

TABLE A-3 (CONT'D)

Plant Code	Output (MMkWh/yr)	Average Cost (mills/kWh)
1	3226.0	11.49
2	12055.1	14.06
3	6800.0	13.46
4	4454.6	11.75
5	1089.9	14.44
6	2875.0	25.41
7	10284.6	14.70
8	4321.0	16.35
9	14649.0	8.16
10	4312.1	17.42
11	12462.4	18.18
12	14496.0	7.64
13	6846.9	10.04
14	4525.8	12.37
15	5144.2	16.97
16	2607.5	14.55
17	5177.4	14.84
18	7899.3	13.42
19	3205.7	14.37
20	3816.5	10.80
21	3640.2	17.29
22	8106.3	13.89
23	7951.1	25.14
24	2002.8	20.61
25	4830.5	17.57
26	6143.9	17.03
27	2887.7	19.76
28	6659.3	15.81
29	1762.4	14.24
30	2347.1	13.65
31	2438.3	29.73
32	5117.7	15.60

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