MEASURING ECONOMIES OF HORIZONTAL AND VERTICAL INTEGRATION IN THE US ELECTRIC POWER INDUSTRY: HOW COSTLY IS UNBUNDLING?

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RP 0917

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June 2009

ISBN No: 978-1-85449-757-4

The authors acknowledge financial support from the American Public Power Association, Fundación Repsol-YPF and the Spanish Ministry of Education and Science (SEC2007-67737-C03-2/ECON)

Abstract

Prior to the 1990s, the generation, transmission, distribution and retailing of electricity were generally carried out by integrated monopolies. In recent decades, many governments have introduced reforms, where these firms are "unbundled" to aid with the introduction of competition into the potentially competitive generation and retailing segments of the industry. The success of these reforms hinges on the degree to which gains from improved competition outweigh any lost scope economies. In this paper we use data on 116 investor-owned utilities (IOUs) from the US in 2001 to investigate vertical scope economies between generation and distribution and horizontal scope economies between different types of generation. Our quadratic cost function model includes three generation output measures (hydro, nuclear and fossil fuels), which not only allows the calculation of horizontal scope economies, but also allows one to investigate the effect that generation mix has on vertical scope economies. Our empirical results provide (sample mean) estimates of vertical scope economies of 8.1%, horizontal scope economies of 5.4% and global scope economies of 13.5%, suggesting that policy makers should think carefully about unbundling reforms. Finally, an extensive sensitivity analysis is used to show how the scope measures vary across alternative model specifications and firm types.

1. Introduction

Prior to the 1990s, the generation, transmission, distribution and retailing of electricity was generally carried out by vertically integrated utilities, which were either state-owned monopolies (e.g. in most European countries) or tightly regulated private companies (e.g. in most parts of the United States). In recent decades, many governments have questioned the degree to which all four of these components of the electricity supply industry are natural monopolies (Newbery, 2000). As a consequence, they have introduced reforms aimed at introducing competition into the potentially competitive generation and retailing segments of this industry, while maintaining regulated (or government-owned) monopolies in the transmission and distribution segments. In many cases, governments have argued that competition in the generation and retail sectors is best served by separating (or unbundling) the incumbent vertically integrated entities into separate generation, transmission, distribution and retail organisations (as well as allowing new entrants in the competitive segments).

Following the pionerring reforms in the UK in the 1990s, commonly considered the gold standard for electricity sector reform (Joskow 2008), the unbundling principle has become an integral part of the policy packages in many countries, which have embarked on the process of introducing competition in their electricity markets. The economic rationale for vertical separation is the prevention of potential anti-competitive effects that could result from the exploitation of market power amongst the stages of electricity supply. However, in addition to this, the economic case for unbundling also implicitly relies on the premise that cost savings resulting from vertical integration economies, if they exist, are unlikely to be substantial. Otherwise, the increase in costs resulting from the loss of economies of integration could potentially outweigh the benefits gained from the introduction of competition.

This is an important issue, which appears to have received limited attention in recent policy debates, perhaps because of the limited amount of empirical evidence that is available. Pittman (2003, p13) notes that in the electricity industry “econometric estimates of scope economies have yielded somewhat mixed results”. Similarly, Sirasoontorn and Quiggin (2007, p412), in their recent discussion of reform options in Thailand, note that “Evidence on network and scope economies remains ambiguous”. Therefore, in this study our focus is on obtaining up-to-date, robust estimates of the cost economies (or diseconomies) associated with vertical integration. Moreover, as we allow for multiple types of generation, unlike most previous studies, this not only allows for better estimates of vertical economies, but can also provide evidence on horizontal integration economies and how a firm's generation mix influences vertical, horizontal, and overall integration economies. This information should provide a valuable contribution to the current debate on the relative merits of vertical and horizontal unbundling, where at present we observe that some governments are implementing an unbundling reform process, while others, for example the UK, have permittied mergers among entities that were not long ago formed by unbundling vertically integrated organisations.

At the time of the early British reforms, a seminal paper by Kaserman and Mayo (1991) was published in *The Journal of Industrial Economics*. This paper estimated vertical economies in the US power sector, and contained various important features. First, from a methodological perspective, it paved the way in terms of providing a methodology for the measurement of economies of vertical integration. Second, at a time when various reforms involving vertical separation were underway, it was virtually the only available study at that time that provided an estimate of vertical economies. Finally, Kaserman and Mayo's findings were rather challenging in that they suggested that efficiency losses resulting from splitting generation from the transmission/distribution of electricity were substantial.

The empirical studies on vertical integration in the electricity industry that followed Kaserman and Mayo (1991) are not abundant, which is somewhat surprising given the wave of restructuring reforms that followed the lead of the UK. Furthermore, virtually all of these studies obtain estimates of substantial scope economy gains resulting from vertical integration. Particularly, the most recent estimates on vertical economies with US data (Kwoka 2002) suggest quite substantial costs of vertical disintegration, which may lead one to reconsider the advisability of further unbundling.

Given this background, this paper contributes to the literature in various ways. First, from a conceptual/theoretical perspective, we provide an integrated analysis of both vertical economies and horizontal economies (i.e. among types of generation) into an aggregate measure of global scope economies. Second, from an empirical perspective, we employ more recent data than any past US studies, which are mostly based on data from the 1980s. Particularly, given technological change in computer systems, and more sophisticated coordination mechanisms in power pools than those that existed in the 1980's, there is reason to believe that there has been a change in the degree to which vertical integration is needed to facilitate the coordination of electricity supply. Third, in contrast to earlier studies, we also provide estimates from a variety of model specifications with alternative output definitions and also provide tests of statistical significance for the scope economy estimates. Finally, we provide an analysis of the impact of generation composition (hydro, nuclear and fossil fuel) on the magnitude of vertical economies, which suggests that because vertical, horizontal and global scope economies are dependent on the type of generation employed, there is no "one-size-fits-all" measure of scope economies.

The remainder of the paper is organized into sections. Section 2 contains a comprehensive and updated literature review, while Section 3 provides definitions of the various scale and scope economies measures used in our empirical analysis. The quadratic cost function and associated econometric estimation methodology is detailed in Section 4, followed by a description of the sample data and variable definitions in Section 5. In Section 6 we present and discuss our empirical results, while concluding comments are made in Section 7.

2. Literature review

Electric power has a number of characteristics that are key to understanding the interdependencies that exist between the vertical stages of the electricity supply industry. Thus, before reviewing the empirical literature, we first briefly summarise the most salient characteristics of the industry.

2.1 Characteristics of electric power supply

First, generators must be physically connected to customers through transmission and distribution facilities (i.e. a network of poles, wires, and transformers). Secondly, electricity is a non-storable good, which requires a continuous and instantaneous matching of resource output to customer loads. Third, changes in demand are instantaneously transmitted to the supplier, who must maintain sufficient reserves to meet the maximum contemporaneous demand. Finally, unlike goods in other networks (e.g. gas, water, trains, and information) electricity flow cannot be directed from one point to another in the transmission network over a specific path, like the one specified in a contract. Instead, the electric current within a network is governed by physical laws (Ohm's and Kirchoff's laws). Thus, power travels over all available paths between generation and customer loads and divides itself in accordance with the lines' electrical impedance[1]. As a result, power losses are not proportional to the current flowing in a circuit. Instead, losses increase with the square of the current and, consequently, marginal losses far exceed average losses. These laws imply that the addition of one more power transaction to a given network creates uncompensated externalities (e.g. increased network congestion and power losses).

From the above it follows that the reliability of generating, transmitting and distributing functions are unavoidably interdependent. Hence, some control is necessary in order to regulate system frequency and stability, as well as to provide a synchronized response to emergencies. Further, technical interdependence among generation, transmission, and distribution implies that the design and operation of each vertical segment of the system must be carried out by taking into account the design and operation of the other segments. In this respect, efficient planning and investment requires the exchange of accurate information between vertical levels, as well as maximum protection against uncertainty and risk, given the large quantities of capital necessary to finance long-lasting investments in idiosyncratic assets.

Consequently, the achievement of an efficient supply of electricity calls for considerable coordination of planning and operation both within and between the different vertical stages of the electric power system. Thus, short-run and long-run efficiency requires the coordination of generation, transmission and distribution plant investment, the economic dispatch of generating units, the planning and coordinating of maintenance scheduling, and the maintenance of adequate spinning reserves (Jurewitz, 1988).

Due to the benefits associated with coordinated decision making, it seems reasonable to consider vertical integration as the organizational choice that enables the realization of such potential efficiencies. Thus, it was been traditionally claimed that vertical integration reduces transaction costs, mitigates the problems of information asymmetry, helps to lessen uncertainty and risk, and reduces overhead costs by sharing common resources among stages (e.g. Joskow and Schmalensee 1983, Landon 1983, Jurewitz 1988, Michaels 2006). In principle, such economies appear to be more difficult to obtain by means of coordinated

[1] Impedance is a measure of the overall opposition of a circuit to current, in other words: how much the circuit impedes the flow of current. It is like resistance, but it also takes into account the effects of capacitance and inductance (which vary with the frequency of the current passing through the circuit). Impedance is measured in ohms.

mechanisms between independent companies each operating in different vertical segments of the industry. Accordingly, the unbundling required by electricity industry restructuring would appear to imply the loss of vertical integration economies.

By contrast, the advocates of deregulation work under the premise that the economies created by vertical integration are unlikely to be great, and therefore the change in market structure would not entail significant costs, and therefore is likely to be more than offset by cost savings due to increased competition in energy supply. However, the costs associated with vertical unbundling are in principle empirically estimable, and are also an important factor to consider when assessing the benefits of industry restructuring that is designed to facilitate increased competition. Nevertheless, somewhat surprisingly, empirical studies are not particularly abundant, as is demonstrated by Table 1, which provides an updated review of empirical studies examining vertical economies in the power sector.

[Place Table 1 about here]

2.2 Empirical Studies

The pioneering empirical studies aimed at detecting potential advantages of vertical integration were centred on testing the separability of the cost or production function among production stages (e.g. Henderson 1985, Roberts 1986, Lee 1995, Thompson 1997, Hayashi et al 1997). All of these studies analyze the separability between the generation and transmission/distribution stages in US Investor Owned Utilities (IOU) power sector, and provide evidence that transmission and distribution are not separable from generation. Basically, this means that downstream costs depend on input usage at the generation stage, so firm decisions concerning input use at each stage cannot be made independently. Nevertheless, although the rejection of the separability hypothesis suggests the existence of vertical integration gains, the separability approach does not permit the quantification of the magnitude of such economies.

Using a slightly different research approach, Gilsdorf (1995) tests sub-additivity and cost complementarity (Gilsdorf 1994) for 72 vertically-integrated US utilities in 1985. The utilities included in his sample produced at least 65% of their power from conventional (non-nuclear) steam generation. He found no evidence of sub-additivity nor cost complementarity between generation, transmission and distribution stages (i.e. that the marginal cost of producing one good does not decrease when the output of the other good increases). However, scope economies may exist in the absence of sub-additivity and cost complementarities (Baumol et al, 1982).

Eftekhari (1989) was the first empirical study to utilise the concept of economies of scope to estimate the economies of vertical integration using data on a cross section of 61 US electric firms for 1986. He estimated a multi-stage translog cost function by applying the Box-Cox transformation to the output variables in the translog model, prior to estimating the cost function together with the corresponding input cost-share equations using Zellner's (1962) iterative SUR procedure. His sample only includes firms which generated at least 80 percent of their power by conventional steam methods and did not have any nuclear generating capacity. He found evidence of diseconomies of joint production between generation, transmission and distribution.

Kaserman and Mayo (1991) estimates a quadratic cost function, that allows for the specification of stage-specific fixed costs, using ordinary least squares (OLS) estimation. Their function also includes a number of hedonic variables to account for cross-sectional variation in input prices that may have an influence upon a utility's costs. They use data on 74 privately owned electric utilities in 1981 and obtain empirical evidence of the existence of economies of vertical integration in the generation and transmission/distribution of electric supply, in contrast to the Eftekhari (1989) study. They found that vertical economies prevail throughout the relevant range of outputs. Particularly, they found vertical economies of 12 percent for a firm producing the sample mean generation and distribution levels (9 and 7.3 million MWh, respectively). Further, they estimate the degree of vertical economies for various levels of generation and distribution, and find that it reaches a maximum of 95% for a utility that generates 18 million MWh and distributes 14 million MWh (i.e. twice the mean values).

Kwoka (2002) is the most recent study to utilise data for US IOUs. It involves the OLS estimation of a quadratic cost function using data on a cross section of 147 firms in 1989, which provides estimated cost savings of about 42 percent for a utility producing the sample mean levels of output (13.6 million MWh of generated power and 15.4 million MWh of distribution). These estimates are unusually large, but this may be in part a consequence of including wholesale sales of electricity in the distribution output measure.

Greer (2008) estimated a quadratic cost model using data on US rural electric cooperatives in 1997. As in Kaserman and Mayo (1991), the cost function is quadratic in the outputs and separable from input prices, which are only included as linear expressions. Greer reports average cost savings slightly above 40% when evaluated at the sample mean (i.e. a rural cooperative with a generation of 320 GWh and 300 GWh of distributed power).

Studies from other countries are less common (refer to Table 1). These studies incorporate a variety of approaches and methodological refinements. Ida and Kuwahara (2004) found evidence of weak cost complementarities in their analysis of nine Japanese utilities over the 1978-98 period. They specify a translog cost function and associated share equations, which is estimated using a fixed effects seemingly unrelated regressions (SUR) estimator.

Nemoto and Goto (2004) estimate a symmetric generalized McFadden cost function using panel data on nine Japanese electric utilities over 1981-1998. They adopt a new perspective by focusing on the estimation of technological externalities between the generation and transmission-distribution stages. Their results confirm that generation capital significantly raises transmission-distribution costs as if it were a negative externality. Consequently, their results suggest that the generation stage is inefficiently overcapitalized if it is separated from the transmission-distribution stage. These external diseconomies would be eliminated by vertical integration that enables centralized decision making over all stages.

Jara-Díaz et al (2004) specify and estimate a quadratic cost function together with the corresponding input expenditure equations, on a sample of 12 Spanish utilities during the period 1985-1996. Together with the distribution output, they specify four different generation products (e.g. MWhs of power generated from coal, nuclear, oil and hydro), which allows estimating economies of scope at the generation level. They found that the vertical integration of generation and distribution of power saves around 6.5 percent of costs evaluated at the sample mean (8,200 GWh generation and 11,350 GWh distributed), while cost savings derived from the horizontal integration of diverse generation outputs into a single firm (as opposed to the splitting up amongst various separate specialized firms) ranged from 9.1% to 28.1%.

Fraquelli et al (2005) test for the presence of economies from vertical integration using a sample of 25 Italian local electric utilities. They estimate a *composite cost function*[2] and the associated input cost share equations using a non-linear iterated SUR (NLSUR) estimator. They found statistically significant vertical economies of 3 percent for the average firm (which generates about 300 million kWh and distributes about 600 million kWh).

Houldin (2005) studies the case of the Ontario (Canada) power system, using an accounting based analysis of total cost figures of the electricity industry before and after its restructuring. While, the methodology employed to measure vertical economies is not documented, the paper concludes that vertical unbundling provoked a loss of scale and scope economies, and this increased real average costs by 5 percent.

Finally, Arocena (2008) estimated economies of vertical integration and economies of diversification in generation in a sample of Spanish utilities by means of Data Envelopment Analysis. Further, the potential gains of vertical and horizontal integration are evaluated not only on the basis of cost savings but also on the increase in the quality of service attributable to integration. This study found evidence that vertical integration reduces cost and improves quality in the range of 1.1 to 4.9 percent, whereas economies of horizontal integration in generation range between 1.3 and 4.3 percent.

The discussion above and the summary material contained in Table 1 shows that past studies have come to a range of conclusions regarding the degree of vertical scope economies. These differences are likely to be the consequence of a variety of factors, some of which are outlined below.

- Data sourced from a variety of countries in a variety of time periods.
- A few studies consider generation output measures disaggregated by type, while most studies restrict their attention to one type of generation (fossil fuels) or alternatively aggregate differing generation types into a single output measure.
- Studies use a variety of distribution output measures, such as customer numbers versus the amount of electricity delivered.

[2] The composite cost function is quadratic in the output vector and log quadratic (like a translog function) in the input price vector.

- Some studies include a range of extra variables in their models, such as regional dummy variables, output activity dummy variables (to capture fixed costs) and various production characteristics (relating to density, etc.).
- Some studies use single-equation econometric estimation methods, such as ordinary least squares (OLS), while others use multi-equation methods, such as SUR, with the latter approach potentially allowing one to obtain more efficient estimates.
- A number of different functional forms are considered, including the translog functional form which does not permit zero output values and hence does not allow the calculation of the standard economies of scope measures.
- A number of studies impose the restriction that the cross-product terms between output quantities and input prices are equal to zero. This restrictive assumption implies that output composition has no influence on how a firm reacts to changes in the relative input prices of capital, labour, etc.

In our empirical analysis we attempt to consider as many of these issues and modelling approaches as possible. In terms of data, we make use of more recent data from the US electricity industry, as data in past studies is two decades or more old. In terms of modelling, we estimate a quadratic cost function (involving non-zero cross products) using SUR methods. In order to allow an analysis of horizontal integration issues, we include three generation output variables (nuclear, hydro and fossil generation) in our model, but also study the impact of aggregation on our results by estimating models with a single aggregate output variable. While we argue that distribution output is best proxied by a measure of customer connections, we also do some sensitivity analysis and provide alternative estimates with distribution output defined with a MWh's delivered measure. Finally, we consider a range of additional variables, including regional dummy variables, output activity dummy variables and other operating characteristics, so as to investigate the sensitivity of our results to their inclusion.

3. The measurement of scale and scope economies

In this section we define the measures of scale and scope economies that are utilised in the empirical analysis.

3.1 Scale economies

The degree of scale economies defined over the entire product set *N*, at *y*, is given by (Panzar and Willig, 1977)

$$S_N(y) = \frac{C(y)}{y \cdot \nabla C(y)} = \frac{C(y)}{\sum_{i=1}^{n} y_i C_i(y)}, \qquad [1]$$

where $y = (y_1, y_2, ..., y_n)^t$ is a $n \times 1$ vector of products, $C(y)$ is the cost function and

$C_i(y) = \frac{\partial C(y)}{\partial y_i}$ is the marginal cost of product *i*. [3] There are said to be increasing, decreasing or constant returns at *y* if $S_N(y)$ is greater than, equal to, or less than unity, respectively. Therefore, if increasing returns to scale are present, ($S_N > 1$), a proportional growth of all products induces a less than proportionate increase in costs.

When a firm exhibits ($S_N > 1$), marginal cost at *y* are lower than average cost, implying that the firm could lower its average cost by expanding production. Since the firm would gain from increased production, it is said to be operating with economies of scale (or size). Conversely, if ($S_N < 1$) then at *y* the potential proportional change in cost would exceed the proportional change in output and thus, the firm is operating with diseconomies of scale.

The above concept of *global scale economies* relates to proportional changes in all the quantities in the entire product set. However, as Baumol, et al (1982) notes, another analytically important way in which the magnitude of a firm's operations may change is through variation in the output of one product, holding the quantities of other products constant. *Product-specific scale economies* are therefore based on changes in costs when one output quantity changes while all other outputs are held constant. Product-specific economies of scale for y_i are therefore defined as:

$$S_i(y) = \frac{IC_i}{y_i C_i} = \frac{C(y) - C(y_{N-i})}{y_i C_i} = \frac{AIC_i}{C_i}, \qquad [2]$$

[3] Chambers (1988) calls this measure elasticity of size to distinguish it from the more common elasticity of scale. They only coincide if the production function is homothetic and, the cost function is separable.

where IC_i represents the incremental cost of producing output i, $C(y_{N-i})$ is the cost of jointly producing all the outputs except output i,[4] and AIC_i represents the average incremental cost, $AIC_i = \frac{IC_i}{y_i}$.

Thus, the degree of product-specific economies of scale for y_i is measured by the ratio of AIC_i for the product relative to its marginal cost. *AIC* is analogous to ray average cost. Returns to scale with respect to output type *i* are said to be increasing, constant or decreasing as S_i is greater than, equal to, or less than unity, respectively.

It is also possible to define an alternative scale economy measure that is specific to a subset of outputs $T \subseteq N$ as:

$$S_T(y) = \frac{IC_T(y)}{\sum_{j \in T} y_j C_j(y)} = \frac{C(y_T) - C(y_{N-T})}{\sum_{j \in T} y_j C_j(y)} \qquad [3]$$

Returns to scale economies specific to the product subset *T* are said to be increasing, decreasing or constant as $S_T(y)$ is greater than, less than or equal to unity, respectively. Note that equation [3] is equal to equation [1] when $T = N$.

This measure is particularly useful, in a vertically integrated structure. Thus, if *T* denotes the subset of upstream products, and *N-T* the subset of downstream products, equation [3] reports the degree of stage-specific scale economies. For example, if *T* is the subset of power generation products and *N-T* consists of the subset of power distribution products, then equation [3] captures the degree of generation-specific scale economies, and an analogous measure could be constructed for the N-T subset to measure distribution-specific scale economies.

3.2 Scope economies

In addition to the potential for scale economies, there also exists the possibility of obtaining cost savings resulting from the joint production of a bundle of products in a single company, as contrasted with their separate production in specialized firms. Economies of scope are said to exist if it is more efficient to produce several different products within a

[4] That is, $y_{N-i}=(y_1,y_2,\ldots,y_{i-1}, 0, y_{i+1},\ldots,y_n)$.

single diversified firm than splitting up the production of each product, or subset of products, between separate specialized firms.

Hence, scope economies relate to the increment of costs resulting from splitting up the output set into two product lines T and N-T, where the output vectors of specialized firms are restricted to be orthogonal to one another, that is, such that $y_i \cdot y_j = 0$, i≠j. Economies of scope are said to exist if the following condition holds

$$C\left(y_T\right)+C\left(y_{N-T}\right)>C\left(y_N\right) \qquad [4]$$

and diseconomies of scope occur if the inequality is reversed.

The degree of scope economies at y relative to T is defined as

$$SC_T(y)=\frac{C\left(y_T\right)+C\left(y_{N-T}\right)-C\left(y_N\right)}{C\left(y_N\right)}. \qquad [5]$$

Fragmenting the production into these two subsets increases, decreases or leaves unaltered the total cost when $SC_T(y)$ is greater than, less than or equal to zero, respectively. In other words, if $SC_T(y)>0$ it is cheaper to jointly produce all of the products in vector y than to separately produce the output vectors y_T and y_{N-T}.

Variation in a firm's scope of operations may result in the vertical and/or horizontal dimension. As an example, in the case of a pure generating company, vertical scope expands if it enters the distribution business. In contrast, a change in the firm's horizontal scope refers to a change in the degree of product diversification within a specific stage of the vertical chain. For example, this occurs when a hydro generating company modifies its production mix by adding nuclear or thermal power generation.

Given the distinction between vertical and horizontal scope, if T denotes the subset of upstream products, and N-T the subset of downstream products, then equation [5] measures the degree of vertical integration economies. For example, if N denotes the full output set, T is the subset of power generation products and N-T consists of the subset of power distribution products, then equation [3] captures the degree of generation-specific scale economies. In the same vein, if N refers to generation outputs only, T a subset of certain generation types (e.g. nuclear generation), with *N-T* including those generation products not included in *T* (e.g. thermal generation) then equation [5] identifies the economies of horizontal diversification in the generation stage.

Following Baumol et al (1982: 74), a further basic relationship emerges when we divide the product set *N* into two disjoint subsets *T* and *N-T,* a relationship that highlights the integral role played by economies of vertical integration in the relationship between stage-specific scale economies and aggregate scale economies:

$$S_N(y) = \frac{\alpha_T S_T(y) + (1-\alpha_T) S_{N-T}(y)}{1 - SC_T(y)}, \qquad [6]$$

where $\alpha_T = \dfrac{\sum_{j\in T} y_j \dfrac{\partial C(y)}{\partial y_j}}{\sum_{j\in N} y_j \dfrac{\partial C(y)}{\partial y_j}}$.

Equation [6] indicates that in the absence of interdependencies between products in *T* and *N-T* (i.e. $SC_T(y) = 0$), the degree of global scale economies $S_N(y)$ is simply a weighted sum of its component product-specific scale economies. Thus, if *T* refers to the generation outputs and *N-T* the distribution outputs, then equation [6] indicates the way in which the economies of vertical integration $SC_T(y)$ magnify the effects of stage-specific scale economies in the determination of overall scale economies. When $SC_T(y) > 0$, the denominator in [6] is less than one, and $S_N(y)$ is larger than the weighted sum of the stage-specific scale economies. Therefore, even if scale diseconomies are present in both stages, the presence of sufficiently strong economies of vertical integration can result in the presence of scale economies over the entire product set.

3.3 Overall scope and the economies of full specialisation

Given the potential presence of both horizontal and vertical scope economies, we extend the approach of previous studies and next emphasize the degree of overall scope economies as a measure that aggregates the diverse sources of economies of integration in a multi-stage context.

Let us consider a firm that produces n products, of which k are produced upstream (e.g. generation) and n-k are produced downstream (e.g. distribution). Let N be the entire set of n products produced by the firm. Let us now consider two subsets of N $S_U \subseteq N$ and $S_D \subseteq N$, such that $S_U \cup S_D = N,$ and $S_U \cap S_D = 0$. S_U includes the upstream products $y_U = (y_1, y_2, \ldots, y_k)$ and S_D including the downstream products $y_D = (y_{k+1}, \ldots, y_n)$. Let $P_U = \{T_1, T_2, \ldots, T_p\}$ be a non-trivial partition of S_U. That is, $\cup_i T_i = S_U$, $T_i \cap T_j = 0$ for $i \neq j.$ $T_i \neq 0,$ $p > 1$. Similarly, let $P_D = \{T_1, T_2, \ldots, T_q\}$ be a non-trivial partition of S_D, such that $\cup_i T_i = S_D$, $T_i \cap T_j = 0$ for $i \neq j.$ $T_i \neq 0,$ $q > 1$.

There are horizontal economies between upstream products in y_U with respect to the partition P_U if

$$\sum_{i=1}^{k} C(y_i) > C(y_U) \qquad [7]$$

There are horizontal economies between downstream products in y_D with respect to the partition P_D if

$$\sum_{i=k+1}^{n} C(y_i) > C(y_D). \qquad [8]$$

There are vertical economies between upstream and downstream stages in y if

$$C(y_U) + C(y_D) > C(y_N) \qquad [9]$$

Finally, we define the degree of multistage or global scope economies at y as:

$$GSC_N(y) = \frac{\left[\sum_{i=1}^{k} C(y_i) - C(y_U)\right] + \left[\sum_{i=k+1}^{n} C(y_i) - C(y_D)\right] + \left[C(y_U) + C(y_D) - C(y_N)\right]}{C(y_N)} \qquad [10]$$

$$= \frac{HE_U + HE_D + VE}{C(y_N)}$$

where HE_U measures the cost savings derived from the horizontal integration between upstream products, HE_D represents the cost savings from horizontal diversification downstream, and VE is the cost savings from vertical integration between both stages. If

$GSC_N(y)$ >0 this indicates that the costs of producing all products jointly in a single company is strictly lower than producing the same levels of products in n separated specialized units. That is, equation [10] compares the costs of full integration with those of full specialization, and thereby indicating the degree of aggregate or overall scope economies as the proportion of such cost savings on the total integrated costs. However, equation [10] also indicates that regardless of whether overall scope economies are present, one or more of upstream horizontal economies, downstream horizontal economies and vertical economies may or may not be present.

4. Empirical model specification

We use a quadratic cost function, which is a flexible functional form (i.e. it provides a second order approximation to any arbitrary functional form) and also has the advantage that it is well defined for zero output values. This latter feature, which is particularly important for measuring scope economies, is not satisfied by some other popular flexible forms, such as the translog cost function.

The quadratic cost function specification can be written as follows:

$$CT_i = \alpha_0 + \sum_{g=1}^{n} \beta_g y_{gi} + \sum_{g=1}^{m} \delta_g w_{gi} + \frac{1}{2}\sum_{g=1}^{n}\sum_{j=1}^{n} \beta_{gj} y_{gi} y_{ji} + \frac{1}{2}\sum_{g=1}^{m}\sum_{j=1}^{m} \gamma_{gj} w_{gi} w_{ji}$$

$$+\sum_{g=1}^{n}\sum_{j=1}^{m} \theta_{gj} y_{gi} w_{ji} + \sum_{g=1}^{h} \psi_g Z_{gi}\,, \quad i=1, 2, \dots, f. \qquad [11]$$

where CT_i = total costs of the i-th firm, y_{gi} = quantity of output g, w_{gi} = price of input g, Z_{gi} = operating variables, n = number of outputs, m = number of inputs, h = number of operating variables, f = number of firms in the sample and the Greek characters represent unknown parameters to be estimated.

By applying Shephard's Lemma to equation [11], and given the assumption of symmetry for the β and γ parameters, we obtain the m factor demand equations as:

$$x_{gi} = \frac{\partial CT_i}{\partial w_{gi}} = \delta_g + \sum_{j=1}^{m} \gamma_{gj} w_{ji} + \sum_{j=1}^{n} \theta_{jg} y_{ji}\,, \quad i=1, 2, \dots, f, \quad g=1, 2, \dots, m. \qquad [12]$$

where x_{gi} = the quantity of input g.

For the purpose of econometric estimation, we append disturbance terms, v_{gi}, to the m+1 mathematical equations defined in [11] and [12] to produce the set of m+1 stochastic equations in [13] and [14].

$$CT_i = \alpha_0 + \sum_{g=1}^{n} \beta_g y_{gi} + \sum_{g=1}^{m} \delta_g w_{gi} + \frac{1}{2}\sum_{g=1}^{n}\sum_{j=1}^{n} \beta_{gj} y_{gi} y_{ji} + \frac{1}{2}\sum_{g=1}^{m}\sum_{j=1}^{m} \gamma_{gj} w_{gi} w_{ji}$$
$$+ \sum_{g=1}^{n}\sum_{j=1}^{m} \theta_{gj} y_{gi} w_{ji} + \sum_{g=1}^{h} \psi_g Z_{gi} + v_{0i}, \quad i=1, 2, \dots, f \qquad [13]$$

$$x_{gi} = \frac{\partial CT_i}{\partial w_{gi}} = \delta_g + \sum_{j=1}^{m} \gamma_{gj} w_{ji} + \sum_{j=1}^{n} \theta_{jg} y_{ji} + v_{gi}, \quad i=1, 2, \dots, f \quad g=1, 2, \dots, m. \qquad [14]$$

Each of these disturbance terms are assumed to have zero mean, constant variance and to be uncorrelated (i.e. $E(v_{gi}) = 0,\ \mathrm{E}(v_{gi}^2) = \sigma_{gg},\ E(v_{gi}v_{gj}) = 0,\ \forall i \neq j,$ i,j=1, 2, … , I, g=0, 2, … , m). They are designed to capture those factors which differ across the firms but are not captured by the included regressor variables, such as the effects of strikes, bad weather, etc. Furthermore, we allow for the possibility that there may be contemporaneous correlation across equations for a particular firm (i.e. $E(v_{gi}v_{qi}) = \sigma_{gq},\ E(v_{gi}v_{qj}) = 0,\ \forall i \neq j,$ i,j=1, 2, … , I, g,q=0, 2, … , m). For example, when particular weather conditions impact on a firm they are likely to affect more than one equation.

The unknown parameters in the system of m+1equations, comprising the total cost equation [13] and factor demand equations [14], are estimated using Zellner's (1962) iterative estimating procedure for seemingly unrelated regressions (ITSUR). Following standard practice, variables are expressed as deviations from their respective sample means, which permits a direct interpretation of the first order parameters as estimates of marginal effects at the sample mean.

Linear homogeneity in input prices is imposed by normalizing total cost and the input prices by an arbitrarily chosen input price variable (the *m*-th). In addition, we impose cross-equation restrictions to ensure symmetry in the second cross-partial derivative terms (Youngs' Theorem). Other regularity conditions involving inequality restrictions, such as monotonicity and concavity are checked at each data point in our empirical analysis.

5. Sample Data

5.1 The sample

Data for 116 Investor Owned Utilities (IOUs) for the year 2001, was sourced from the Platts Powerdat Database, where the primary source of this data is FERC Form 1 or other related regulatory returns. Table 2 presents sample descriptive statistics of the variables, while Table 3 illustrates the diversity in the sample by providing sample averages for various firm types observed in the data. An important feature of our database is that it includes a wide variety of firm sizes, as well as an ample diversity of types and degrees of vertical integration. Thus, as Table 3 illustrates, our sample includes not only generation only, distribution only, and highly vertically integrated utilities, but also a wide sample of firms with varying degrees of vertical integration. Moreover, our sample also includes wide variation in the degree of horizontal diversification in generation, as it includes examples of firms that specialize in a single generation technology, two generation technologies, and highly diversified generators using all three generation types indentified in our study.[5]

[Place Tables 2 and 3 about here]

5.2 Definitions of variables

<u>*Outputs*</u>

In terms of electricity generation, the majority of past studies (refer to Table 1) have specified one single generation output variable as the quantity of power generated (*G*) in Mwhs. One notable exception was Jara-Díaz et al (2004) where separate output measures were specified

[5] This diversity in firm types is very important when estimating a cost function for the purpose of calculating scope economies, because it reduces the likelihood that we are making use of cost function predictions that are outside of the range of our sample data. Hence, we are able to obtain estimates which have lower standard errors than would otherwise be the case if our data set was not as diverse as it is.

for power generated from different sources. In our analysis, we also consider separate generation output measures, namely: generation with conventional fossil fuels (*G1*), nuclear generation (*G2*) and hydro generation (*G3*).[6] This disaggregation has a number of advantages. First, we argue that this avoids potential misspecification error by allowing for the considerable differences across these three technologies.[7] Second, it allows us to investigate both the horizontal and vertical relationships that exist between generation and distribution activities, as discussed in the previous sections.[8]

Regarding the measurement of the output of the distribution activity, the studies listed in Table 1 have mostly used the amount of energy delivered in Mwh's (*D1*) as their distribution output measure. A few of these studies have instead used the number of customers served (*D2*). In our experience, we have found that customer numbers is the key cost driver in empirical analyses of electricity distribution. This is supported by a number of authors, such as Weiss (1975), Neuberg (1977), Wangensteen and Dahl (1990), Salvanes and Tjøtta (1994) and Burns and Weyman-Jones (1996). Hence we use customer numbers as our preferred distribution output measure. However, given the popularity of the *D1* measure, we also run some extra models to test the sensitivity of our results to this choice.[9]

Input prices, quantities and costs

The Total Costs (TC) measure includes operation and maintenance costs from generation and distribution related activities, overhead expenses and capital costs (KC) calculated using a capital price (K) obtained using the weighted average cost (WACC) of the capital stock plus depreciation costs. Purchased power expenses and transmission costs are excluded so as to

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[6] We also investigate the sensitivity of our results to this disaggregation, by estimating a model with an aggregate generation measure (*G*), as shown below.

[7] Some previous studies have included dummy variables for distribution and generation activities in order to allow for what they term "stage-specific fixed costs", although we are inclined to question the theoretical justification for this in a long-run cost function model. Similarly, previous studies with a single generation output have controlled for generation mix with either dummy variables indicating generation types or generation share variables. Given the past literature, we have tested the appropriateness of this approach by allowing for dummy variables for each of the four potential distinct activities that our sample of IOUS actually engage in, which are Distribution, Conventional Generation, Nuclear Generation and Hydroelectric Generation. As expected, we find that the inclusion of these dummy variables is only statistically significant in those models that assume a single aggregate generation output, which by definition cannot capture the cost implications of different generation technologies. We therefore have excluded any further consideration of these activity dummy variables from the main text.

[8] Note that generation from renewable sources (wind and geothermal) were very minor in this 2001 data (less than 0.001% for the average firm) and hence are not included in the analysis.

[9] Additionally, we note that given the development of retail competition in electricity supply, our study carefully defines distribution outputs to include both full service customers, for which the company is responsible for both power and distribution, and distribution only customers for whom the company distributes power which is provided by another company.

properly model the underlying production relationship between distribution and generation activities. The WACC estimates are those reported in the Platts Database and employ historic cost net plant data, as originally reported in FERC Form 1 as the basis for a measure of the quantity of capital stock (XK), thereby following common regulatory practice. Depreciation expenses are calculated following Gilsdorf's (1994) assumptions of declining balance depreciation expenses.[10]

Measures of fuel price and quantity tend to be fairly standard in most past studies, with fuel quantity (XF) measured in BTUs and fuel price (F) estimated as expenditure on fuel (FC) divided by BTUs of fuel consumption. However, given that we have defined separate generation output variables in our model, we believe that it is important to also include separate fuel price measures for fossil fuels and nuclear fuels. Thus, by using data on fossil fuel costs (CF1) and nuclear fuel costs (CF2) and the quantities of the two fuels measured in BTUs (XF1 and XF2), we can derive prices for fossil fuels (F1) and nuclear fuel (F2). We would argue that the incorporation of these two fuel price variables allows a richer specification of the relationship between different generation technologies, fuel prices, and the resulting estimated economies of integration. Most importantly, this removes the questionable assumption that nuclear and conventional generators face common fuel prices and marginal costs.[11]

Measures of labour price (L) and quantity (XL) were problematic because a considerable number of firms had missing data on the number of employees. Hence we chose to measure the labour price using state-level US Census estimates of average wages paid by IOUs. The quantity of labour is then calculated implicitly as total labour costs (LC) divided by this labour price. These measures are arguably better than those measures that we could have defined if we had access to complete data on employee numbers, because of the likely differences in the average skill levels of employees across different firms which tend to outsource low skill jobs (e.g. security and cleaning) to differing degrees.

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[10] We have also tested the application of Gilsdorf's approach to adjusting historic cost net plant data with Handy-Whitman based capital deflators so as to better reflect economic capital costs. However, as we have found that our results are not particularly sensitive to this adjustment, we have chosen to report estimates with capital cost estimates based on actual reported historic cost net plant data. The alternative estimates are available upon request from the authors.

[11] To further improve the model's consistency with economic theory, we do not assume a zero fuel price for distribution only companies as well as generating companies that do not engage in fossil fuel or nuclear based generation. Instead, firms with zero fuel consumption are assumed to face an opportunity cost for fuel equivalent to that of the average estimated fuel price for those firms with fuel consumption.

The final input variable that we define is an Other Costs (OC) variable. This is a catch-all variable that includes diverse items such as office supplies, outsourced services, etc. A lack of detailed data on the components in this category, combined with degrees of freedom considerations, means that we have specified a single aggregate measure to capture these items. A State-level Census Bureau index of average wages for all employees is used to proxy price differences across States.[12] The quantity measure is then obtained implicitly by deflating the cost measure by this price index.

Other characteristics

A number of previous studies (documented in Table 1) have employed a wide variety of dummy variables and operating characteristics in order to control for differences in the operating environment faced by electric utilities. In this study we also investigate the influence of a number of these variables.

We consider the use of regional dummy variables in order to control for regional heterogeneity not otherwise controlled for in the model. These regions are based on the 10 regional areas identified by the *North American Electric Reliability Council* (NERC) in 2001, and are illustrated in Figure 1.

[Place Figure 1 about here]

We have also considered a number of variables that are designed to capture differences in operating characteristics across firms. These variables include DENSITY (average amount of electricity delivered per customer); RESDENS (average amount of electricity delivered per residential customer); NRESDENS (average amount of electricity delivered per non-residential customer); OHSHARE (proportion of distribution lines that are on overhead poles, as opposed to being underground); LOADFACT (average hourly demand dived by peak hourly demand), SYSTEMUT (power generated dived by generation capacity), are identified and defined in Tables 2 and 3.

Finally, given the development of retail competition in electricity services we also include a previously unused operating characteristic variable, DSHRFULL, which is defined as the proportion of all customers served by a distribution operator who are full service

[12] In an ideal world, we would have used a State-level price index of non-labour, non-capital and non-fuel inputs used in IOUs, however no such index was available. After an extensive search, we selected this price index because we believe that a substantial portion of the other costs aggregate, such as outsourced services, will be heavily influenced by state level differences in the cost of living that are closely related to wage differentials.

customers rather than distribution only customers.[13] This variable serves as a measure to test whether our model results are sensitive to differences in observed levels of retail competition.

6. Estimation results

In this section we report the results of our empirical analysis. As noted in our review of the literature (see summary in Table 1), past studies have reported a wide range of estimates of vertical scope economies, ranging from 3% to 42% (evaluated at sample mean data points). However, these studies have used a variety of data sets, methods and variables in their analyses. Thus, in our empirical analysis we have decided to report results for a range of models, so as to attempt to identify the degree to which some of these modelling choices may be impacting upon the scope measures obtained.

In this section we present and discuss a number of tables of empirical results:

- Table 4 reports likelihood values and likelihood ratio tests for a variety of model specifications;
- Table 5 reports cost elasticities, economies of scale, scope economy and cost estimates (evaluated at the sample means) for a variety of models;
- Table 6 reports disaggregated horizontal scope economy estimates (evaluated at the sample mean) that allow better identification of integration economies between specific generation types;
- Tables 7 reports excess costs estimates (evaluated at the sample means) for 14 different vertical and horizontal partitions of the output vector;
- Table 8 reports global, vertical, and horizontal scope economy estimates for various different firm sizes (with output mix held constant); and
- Tables 9 reports vertical, horizontal and global scope economy estimates for various different generation mixes and integration assumptions (with firm scale held constant at the sample average).

We now discuss each of these tables in turn.

[13] Models with this variable defined based on the proportion of units delivered as opposed to proportion of customers served were also tested, but they did not materially differ from the results reported below.

Table 4 contains log likelihood function (LLF) and LR test values corresponding to a variety of different models. We consider six different output-quantity/input-price specifications. Model (i) is our preferred model, where we have three generation output variables (G1, G2, G3), customer numbers (D2) as the distribution output variable and two fuel price variables (F1, F2). The remaining five models provide some alternatives which allow us to investigate the sensitivity of the results to these choices. Model (ii) is the same as Model (i) except that we use MWh delivered (D1) as the distribution output variable. Models (iii) and (iv) are, respectively, the same as Models (i) and (ii), except that we now employ a single aggregate fuel price variable (F) instead of two disaggregated measures. Lastly, Models (v) and (vi) differ from Models (iii) and (iv) in that they have only the aggregated generation output variable (G) instead of the three disaggregated generation variables. As discussed earlier, we also consider regional dummies and a set of seven operating characteristics. As a consequence we estimate 6×3=18 different models and report their LLF values in Table 4.

The first set of LR tests in Table 4 test for the degree to which the additional variables (regional dummies and operating characteristics) are significant additions to the model. First we note that the operating characteristics are always jointly and individually insignificant additions to the models. Second, we note that the regional dummy variables are always jointly statistically significant. Given this, all subsequent analysis of the reported results is based on models which include regional dummies only.

The second set of LR tests in Table 4 conduct tests of the generation output aggregation. These restrictions are strongly rejected at the 5% level, indicating that aggregation of the generation outputs cannot be accepted in these data. Similarly, the final set of LR tests in Table 5 demonstrate that the restriction of parameters consistent with the imposition of a single fuel price model, is strongly rejected, thereby demonstrating the superiority of the two fuel price specification on a statistical basis.[14]

Finally, we are unable to use standard tests to compare Models (i) and (ii) because they are not nested in each other. However, a comparison of LLF values suggests that Model (i) is a better fit of the sample data, supporting our above choice of customer numbers (D2) as our preferred measure of distribution output. Thus, we feel confident in using Model (i) as our

[14] We note that as the two fuel models require the specification of an additional input share equation, the single fuel specifications (iii) through (vi) are not nested in the two fuel specifications (i) and (ii). The reported test statistics for the restriction to a single fuel price are therefore based on the restriction of parameters in this specification to be consistent with a single fuel specification.

preferred model for our detailed analysis of integration economies. However, before we look at this model in more detail, we will first consider how sensitive the scope measures are to these modelling choices.

[Place Table 4 about here]

6.1 The magnitude of scale and scope economies

Table 5 reports various scale and scope, cost elasticity and cost estimates for the sample average firm for the six models referred to above. Let us first consider the scale economies. As shown in Table 5, the estimates of the degree of global economies of scale (EOS) computed according to equation [1], is quite consistent across the six models, ranging from 1.008 to 1.035. However, in all cases we cannot reject the hypothesis that EOS equals 1 at the 5% level, therefore suggesting the existence of constant economies of scale. This is consistent with much of the empirical literature in this industry, which generally indicates that scale economies in both generation and distribution exhaust for relatively modest sizes.[15]

[Place Table 5 about here]

Despite the consistency of the EOS estimates across the specifications, the distribution (generation) cost elasticities are remarkably lower (higher) in models including distribution customers as an output. As Table 2 shows that average generation costs are 69% of total costs, this suggests that inclusion of distribution customers is important if we wish to properly model total costs. This is intuitively logical as ultimately distribution costs are related more to infrastructure required to provide connections to customers rather than the volume of power delivered to customers.

Following expression [3] we have computed stage-specific economies of scale. Table 5 shows that generation-stage specific scale economies range from 0.911 to 0.966 and are significantly less than 1 in all models, therefore suggesting diseconomies of scale in generation. The degree of distribution-stage specific economies of scale ranges from 0.899 to 0.980, with 4 of the 6 estimates, including all of the models with D2 as the distribution output, being significantly less than 1. These results indicate that the average firm exhibits decreasing

[15] See Christensen and Greene (1976), Huettner and Landon (1978), Joskow (1987), Lee (1995), Salvanes and Tjøtta (1994), Yatchev (2000), Jara-Díaz et al (2004), amongst others.

or constant returns to scale, at best, in the distribution stage. This is consistent with Kaserman and Mayo (1991), who estimate that stage-specific scale economies are exhausted around 5 and 8 million MWh for distribution and generation respectively, well below our average firm, which generates 14.6 million Mwh, distributes 16.9 million and serves 619,200 customers. Salvanes and Tjøtta (1994) and Yatchew (2000) provide evidence from Norway and Canada respectively, and find that minimum efficient scale is achieved by utilities with about 20,000 customers, while larger firms exhibit modest decreasing returns to scale.

Given these stage specific economies of scale estimates, calculation of overall scope economies in the absence of vertical scope economies with expression [6], reveals that the degree of global scale estimates range from 0.942 to 0.967 with all but one of the estimates being significantly different than 1. Therefore, this demonstrates that the average firm would suffer scale diseconomies if vertical scope economies were not present.

Regarding vertical scope economies, computed according to expression [5], Table 5 shows that the estimates range from 4.3 to 9.7 percent and are always statistically significant. In the preferred Model (i) vertical economies are estimated to be 8.1%. Translated into dollar terms, the estimated cost savings associated with vertical scope economies is 64.7 million dollars. Scaling this cost saving up, if all 116 firms in the sample were "reorganized" into 116 identical firms with the same characteristics as the sample average firm, vertical scope economies would be responsible for a costs saving of 7.5 billion dollars.

Putting this result in the policy perspective, if vertical separation between distribution and generation was imposed on the sample average firm, this would imply that the cost savings from competition in generation would need to at least offset this substantial loss before any net benefit from competition could be reaped. As generation amounts to an estimated 69% of costs for the sample average firm, a rough estimation based on model (i) suggests that stand alone generation costs would need to be reduced by 10.8% just to offset lost vertical scope economies.

The estimated economies of full horizontal integration in generation range from 3.4 to 5.4 percent of integrated costs. Translated into dollar terms, the cost savings associated with horizontal scope economies range from 27.0 to 43.5 million dollars, with the highest results being for Model (i). While these estimates are always statistically insignificantly different from zero, this does not imply that horizontal economies are unimportant. Instead, as Table 6 demonstrates, for our preferred model, significant horizontal economies are present between certain types of generation. Thus, there are statistically significant scope economy benefits that accrue from the combination of hydro generation (G3) with G1 and/or G2. This is consistent with the fact that hydro is employed as a peak power source, and largely complements the operation of base load power plants.

[Place Table 6 about here]

Next we compute expression [10] to compare the costs of a fully disintegrated firm consisting of a separate distribution firm and separate fossil fuel, nuclear, and hydro generation firms, with the costs of a fully integrated firm. Table 5 shows that cost savings range from 9.6 to 13.7 percent across the models. Translated into dollar terms, the cost savings associated with global scope economies range from 77.0 to 110.4 million dollars. The results are statistically significant in three of the four multiple generation models and considerably higher in models including two fuel prices.

Taken as a whole, the global, vertical, and horizontal scope economy results suggest that, for the sample average firm, substantial cost savings accrue from both the vertical integration of distribution and the horizontal integration of generation, but the savings from vertical integration are both larger and more statistically significant.

6.2 The costs of alternative partitions of the sample average firm[16]

The vertical, horizontal, and global scope economy measures we have considered so far involve only 3 of the 15 potential structural configurations of the sample average firm's output vector. Moreover, they effectively measure only the most radical options of completely vertically and/or horizontally separating production. As scope related costs interactions will differ for different outputs, alternative partitions of the output vector, would result in alternative costs. Table 7 therefore shows the costs resulting for all possible partitions of the sample average's output vector, computed using the parameters of our preferred Model (i), which are presented in the Appendix. [17]

[16] The analysis of the remainder of the paper and all results in Tables 6 through 9 are based on the estimates of Model (i), which is our preferred model.

[17] We have checked the regularity conditions for the estimated quadratic function. Since homogeneity and symmetry is imposed during the estimation, we check for monotonicity and concavity. In our preferred model, 95% of the observations satisfy monotonicity in input prices, while only 7 observations (6%) violate output monotonicity. Concavity in input prices is also globally satisfied, i.e. the Hessian matrix is negative semi-definite.

[Place Table 7 about here]

Table 7 therefore provides various relevant findings. Firstly, it demonstrates that all potential partitions of the sample average firm's output have higher costs than those of a fully integrated firm, which are 800.8 million dollars. Secondly, it also clearly demonstrates that vertical separation of the average firm is (i.e. partitions 10 to 14), even with full horizontal integration, yields relatively substantial and statistically significant excess cost estimates that range between 64.7 and 108.2 million dollars. Moreover, comparison of partitions 10 and 13 supports the findings of Table 6, as the horizontal separation of hydro generation into a separate generation firm is particularly costly.

Thirdly, partition 4, where vertical integration of nuclear generation is maintained, while conventional and hydro generation are vertically separated but remain horizontally integrated is the least costly partition of the sample average firm's outputs, resulting in a statistically insignificant increase of 2% in costs relative to a fully integrated structure. We would argue that this result again highlights the importance of maintaining horizontal generation of G3 with other generation, but also indicates the significant benefit of vertical scope economies flowing from nuclear generation. However, in general partitions which retain vertical integration with either nuclear or fossil fuel generation have moderate excess costs provided that hydro generation (G3) remains horizontally integrated with the nuclear/fossil fuel (e.g. partitions 4 and 5). Further, while there are strong vertical economies between a horizontally integrated generator producing G1 and G2 and distribution, there are relatively weak vertical economies flowing between G3 and distribution, as the relatively high costs of partitions 8 and 9 reflect. Nevertheless, partition 1 shows that the separation of G3 alone does not increase costs significantly, provided that both G1 and G2 remain integrated with D2. We believe that this is consistent with the fact that the vertical economies in system design are driven by base load sources (nuclear and conventional steam generators) rather than hydro plants. In general, hydro plants are used as regulators of the system in order to meet peak loads and to cover outages of the thermal units. Outages in hydro stations are so infrequent in comparison with thermal power plants that their outage rate can be treated as zero. Further, hydro power stations typically have higher transmission and distribution costs because plants are far from load centres. Additionally, the generally smaller size of hydro plants implies a larger number of units and more disperse locations.

6.3 The impact of size and generation composition on scope economies

In order to measure the impact of firm size on scope economy estimates we consider 12 different rescalings of total generation and distribution customers ranging from 0.25 to 3 times the sample mean. Table 8 below reports global, vertical and horizontal scope economy estimates for the 12 x 12=144 resulting hypothetical firms, after holding the share of generation attributable to the 3 generation outputs constant at the sample average (i.e. shg1 = 77.5% , shg2 = 20%, shg3 = 2.5%). Moving along the diagonal in each panel, the sample average firm is scaled up and down while maintaining the same level of vertical integration (i.e. 619,200 customers and 14.58 million Mwh of total generation). Scope estimates for the average firm are highlighted in the three panels.

[Place Table 8 about here]

Panel A in Table 8 shows the global scope economy estimates. Thus, the value at the bottom-right corner indicates that the partition of a fully integrated company three times larger than the average firm (i.e. G = 43.74, D2 = 1,857.5) into four different companies would increase costs by 10.5%. Note that along the diagonal, the degree of global scope economy estimates do not vary too much when size is increased. In contrast, the cost of full separation is significantly higher for the smallest firm sizes.

The other two panels in Table 8 decompose global scope economies into vertical and horizontal scope economies. Panel B reports vertical economies. All estimates in this panel are positive suggesting benefits from vertical integration for all sizes. This differs from previous studies (e.g. Kaserman and Mayo 1991, Kwoka, 2002), which found vertical diseconomies for the smallest sizes (roughly below 6 million Mwh of G and D).

Furthermore, the negative impact that vertical separation has on costs is smaller in those firms less vertically balanced and more focused on generation, i.e. in those firms with high values of the G/D ratio located to the right of the diagonal. By contrast, firms with a large number of distribution customers relative to generation located below the diagonal are associated with higher economies of vertical integration. In this respect, our estimates in Table 8 seem to suggest a minimum size of generation from which any expansion in the level of distribution results in a greater ability to take advantage of cost savings from vertical integration. To see this, we explore the consequences of holding constant the total generation level and varying the number of customers, i.e. by moving vertically along each column of panel B. Thus, from 10.93 million MWh's, vertical scope economies are maximized at a distribution level which represents a larger scaling of the sample average firm than generation. By contrast, it is observed that for the two smallest generation sizes (generation equal to ¼ and ½ of the sample average, respectively 3.64 and 7.20 million MWh's, maximum vertical economies are attained with a smaller number of customers.

Finally, Panel C in Table 8 shows the magnitude of horizontal scope economies. For the smallest scales, horizontal economies are more salient than vertical economies. In contrast, horizontal economies decrease as we consider larger multiples of the sample average firm. Moeover, horizontal diseconomies appear for companies larger than 25.51 MWh (twice the average firm), suggesting cost advantages related to scale and specialization. Accordingly, large (small) utilities would enjoy greater (lower) cost savings from vertical integration than from the integration of their generating structure.

As discussed above (see Table 6), cost complementarities vary among different types of generation. Therefore, we should expect that the impact of unbundling policies on firms' costs will differ according to their generation mix. In order to measure the impact of generation composition on the magnitude of scope economies, we hold total generation and distribution constant at the sample average but vary the share of total generation accounted for by conventional steam, nuclear, and hydro generation. Thus, in Table 9, the shares of nuclear and hydro generation are denoted by shg2 and shg3 respectively, and fossil fuel generation accounts for the balance. Estimates for the sample average firm's actual generation shares are highlighted in each panel of Table 9, while the maximum (minimum) estimate from the potential 72 alternative generation shares employed in the table are marked in italic (bold).

[Place Table 9 about here]

Table 9 reveals that the estimates of scope economies, and consequently the expected effects of unbundling policies on the average firm's costs, vary substantially with its generation mix. Panel A in Table 9 reveals that global scope economies range from 11.4 to 27.2%. Similarly, Panels B and C in Table 9 show that vertical economies range from 3.3% to 20.6% while horizontal economies range from 3.3 to 8.4%.

Regarding full disintegration, the highest cost penalty would be suffered by a heavily nuclear based company (e.g. 90% nuclear, 8.75% steam, and 1.25% hydro generation), which is the generation mix that exhibits largest global scope estimates at the bottom-left corner of

Panel A. In this case full unbundling would increase costs by 27.2% in comparison to those incurred by a fully integrated company. As Panel B and C show, costs increase 20.6% due to the loss of vertical economies and 6.6% because of the loss of horizontal economies. By contrast, the minimum impact of full separation would be for a company for which generation is 70% fossil-fuel based, 20% nuclear and 10% hydro. In this case, full separation would increase costs by 11.4%, mostly explained by the loss of economies of horizontal integration (6.7%), while vertical separation would imply a cost increase of 4.7%, as shown in Panel B.

Panels B and C provide useful insights for unbundling policies. On the one hand, Panel B demonstrates that as the average firm's nuclear generation increases, the larger the negative impact of vertical separation, due to the loss of vertical integration benefits between nuclear generation and distribution. In contrast, vertical separation would have a lesser effect when the generation of the average firm mostly relies on fossil-fuel and hydro plants. In contrast, Panel C highlights the fact that horizontal divestiture policies would raise costs more, the more generation is based on conventional and hydro generation.

7. Conclusions and policy implications

Vertical unbundling and divestiture is a key aspect of liberalization in many countries that undertake electricity restructuring.For example, during the privatisation of the UK electricity sector in 1990 the former stated-owned Central Electricity Generating Board was dismantled and split up into four companies: three generating-only companies (one of which exclusively operated nuclear generation), and one transmission company. Likewise, the Area Boards that were responsible for power distribution and supply were transformed into twelve Regional Electricity Companies. In the United States, as of February 2003 twenty-four states were active in the restructuring process while the rest were either not actively pursuing restructuring or had delayed the proposals (EIA 2003). In many of those states, mandatory and/or encouraged divestiture of generation assets was adopted. Thus, some state regulators provided strong financial incentives for vertically integrated utilities to divest generation (California did so for fossil-fuel generation), while in others (e.g. Arizona) utilities must divest all of their generation assets if they want complete recovery of stranded costs (EIA 2000, 2003). In this paper, we have estimated the economies of integration in the US power sector and thereby provide a reference for evaluating the potential costs of such unbundling policies.

Our results suggest a statistically significant and substantial cost savings associated with vertical integration, together with a further, but smaller cost saving associated with the horizontal integration of generation. Taken together, global scope savings from vertical and horizontal integration amount to as much as 13.5% of costs for the sample average firm and are statistically significant. The magnitude of our estimates of vertical and horizontal integration economies are substantial enough to give cause for thought, while also suggesting a number of considerations that should be carefully checked before implementing liberalisation polices. In this respect, our results provide useful insights to guide market restructuring, and the subsequent unbundling requirements and divestiture policies intended to create more favourable conditions for competition.

As a general rule, policies favouring vertical separation to foster efficiency gains by facilitating competition can only be considered appropriate if the anticipated/realized gains from competition exceed the cost of foregone vertical scope economies. We would therefore argue that our finding of substantial and statistically significant vertical scope economies of 8.1% for the sample average firm provide a not unsubstantial lower bound for the level of potential cost savings that must be obtainable before vertical unbundling can be justified on cost efficiency grounds. Related to this, Delmas and Tolkat (2005) and Kwoka, et al (2008) find that deregulation in the US electric sector actually had a negative impact on the cost efficiency of utilities in the short term. Moreover, Kwoka et al (2008) also specifically found that divestiture and the subsequent creation of standalone distributors negatively affected the operating efficiency of distribution utilities. Therefore these studies actually provide evidence that supports our findings of substantial losses from foregone vertical scope economies.

With regard to generation, Fabrizio et al (2007) find evidence that IOU generating plants in restructuring regimes reduced their labor and nonfuel operating expenses by 3 to 5 percent in anticipation of increased competition in electricity generation, relative to IOU plants in states that did not restructure their markets. Similarly, Bushnell and Wolfram (2005) find that a measure of fuel use per MWh declined by roughly 2% at divested IOU generation plants. As these estimated efficiency gains are substantially below our estimate that stand alone generation costs would need to be reduced by 10.8% just to offset lost vertical scope economies for the sample average firm, our results suggest that these studies do not provide evidence that the benefits of generation divestiture were sufficient to offset the cost of lost vertical scope economies. Moreover, as we also find that substantial horizontal scope economies exist between different types of generation, it is possible that further losses from generation divestiture may have occurred due to divestiture, which would not have been captured by these plant level studies of generation cost efficiency. Our results therefore suggest that policy makers should more carefully consider the potential benefits of vertical and horizontal integration in future regulatory decisions affecting the electricity industry's structure.

Finally, we would also note that, to our knowledge, our study is the first academic study to systematically analyse the impact of generation composition, which is often determined by historic investment patterns and can only be slowly changed due to the longevity of generation assets, on both vertical and horizontal integration economies, As a result, we have been able to clearly demonstrate that the composition of generation has significant effects on vertical and horizontal scope economy estimates. Composition of generation matters due to the relatively complex interrelationship between different technologies and diversification economies. Thus, for example, our results suggest that the separation of nuclear generation from distribution implies substantial vertical economy losses. This has important policy implications regarding the implementation of unbundling requirements. Thus, for a power system that relies on nuclear power (e.g. France), vertical unbundling may result in significantly higher costs. In contrast, our results suggest that vertical separation of electrical systems based more on hydroelectric generation (e.g. Norway) would arguably have a relatively lower impact on costs. Focusing more specifically on the United States, our results specifically demonstrate that for the sample average IOU, substantial disintegration costs can be best avoided by maintaining vertical integration of nuclear generation, with divestiture of fossil and nuclear generation in a single horizontally integrated generation firm. Thus, our results also suggest that policy makers should carefully consider a system's generation characteristics before determining the appropriateness of policies that would alter the vertical and/or horizontal structure of the electricity sector.

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TABLE 1. Empirical research on economies of vertical integration in the electricity industry

Paper	Sample characteristics	Variables	Functional specification and methodology	Main findings
Henderson (1985)	160 US IOUs in 1970	$C_5 = f(Y_1, Y_{12}, w^l, w_1^k, w_1^f, Z_{16}, Z_{17}, Z_{20})$	Translog cost function and cost share equation system SUR	Separability of cost function between stages is rejected
Roberts (1986)	65 US IOUs in 1978	$C_4 = f(Y_{17}, Y_{18}, Y_{13}, w^l, w_6^k, w_2^p, Z_1, Z_{26})$	Translog cost function and input share equations SUR	Separability of cost function between stages is rejected
Eftekhari (1989)	61 US electric firms from 1986 Each utility generating at least 80% by steam and no nuclear capacity.	$C_3 = f(Y_1, Y_9, Y_{11}, Y_{13}, w^l, w_4^k, w_1^f, Z_{18})$	Box cox transformation of translog cost function and cost share equations. SUR	Diseconomies of joint production
Kaserman and Mayo (1991)	74 US IOUs in 1981 50 G+D 14 D 10 G	$C_1 = f(Y_1, Y_{12}, w^l, w_3^k, w_2^f, w_1^p, Z_2, Z_4, Z_5, Z_6, Z_7, Z_{18}, Z_{22}, Z_{23}, Z_{24})$	Flexible Fixed Costs Quadratic cost function. OLS	Vertical cost complementarities: 11.96% cost savings at the sample mean (G= 9,009 MWh; D= 7,259 MWh) Very small firms (G<6,000; D<6,000) do not show vertical economies
Gilsdorf (1994)	72 US IOUs in 1985 All vertically integrated Each utility must have G at least 65% from non-nuclear steam	$C_2 = f(Y_2, Y_8, Y_{14}, w^l, w_6^k, w_1^f, Z_8)$	Translog cost function and factor share equations SUR.	Evidence against cost complementarity for the 3 output set
Gilsdorf (1995)	72 US IOUs in 1985 All vertically integrated Each utility must have G at least 65% from non-nuclear steam	$C_2 = f(Y_2, Y_{14}, w^l, w_6^k, w_1^f, Z_8, Z_{11}, Z_{12})$	Translog cost function and factor share equations SUR	No evidence of subadditivity for vertically integrated firms
Lee (1995)	70 US IOUs in 1990	$Y_{14} = f(X_1, X_2, X_3, X_4, X_5, X_6)$	Translog production function and cost share equations SUR	Rejects separability hypothesis. separating the functions of generation, transmission, and distribution will result in loss of technical efficiency
Thompson (1997)	85 US IOUs for the years 1977,1982,1987,1992	$C_4 = f(Y_{17}, Y_{18}, w^l, w_6^k, w_2^p, Z_1, Z_{26}, t)$	Translog cost function and cost share equations	Rejection of separability hypothesis

Table 1. continued

Paper	Sample characteristics	Variables	Functional specification and methodology	Main findings
Hayashi et al (1997)	50 US IOUs from 1986-1987 Each utility must have G at least 85% from non-nuclear steam	$C_4 = f(Y_{14}, w^l, w_1^k, w_3^f, w_3^p, Z_3, Z_{13}, Z_{18}, Z_{27}, t)$	Translog cost function and cost share equations for generation, and for vertical integration	Separability of generation from T-D is rejected. Vertical economies: 13.9% -16.8%
Kwoka (2002)	147 US IOUs in 1989	$C_2 = f(Y_1, Y_{14}, w^l, w_1^k, w_1^f, Z_5, Z_7, Z_{10}, Z_{11}, Z_{14}, Z_{15}, Z_{18}, Z_{19}, Z_{23})$	Quadratic cost function OLS	Substantial scope economies. 13%-57% 43% for the average firm (G=15.4 ; D=13.6)
Jara-Díaz et al (2004)	12 Spanish utilities 1985-1996	$C_2 = f(Y_3, Y_4, Y_6, Y_7, Y_{12}, w^l, w_5^k, w_3^f, w_1^i, Z_{11} Z_{29}, t)$	Quadratic cost function and factor share equations SUR	Scope economies between G and D: 6.5% for the average firm (G:8,200; D: 11,350) Horizontal (G) economies: 9.1-10% Full specialization (full unbundling): 28.1%
Nemoto and Goto (2004)	9 vertically integrated Japanese utilities 1981-1998	$C^* = f(Y_1, Y_9, w^l, w^k, w_1^p, Z_{11}, t)$	Symmetric generalized McFadden SUR	EVI exist because of technological externalities between G and T-D:
Ida & Kuwahara (2004)	9 vertically integrated Japanese utilities 1978-1998	$C^* = f(Y_1, Y_9, w^l, w_7^k, w_4^f, Z_{11}, Z_{29}, t)$	Translog cost function and input share equations SUR	Cost complementarities between G and TD
Houldin (2005)	Ontario electricity system, Canada 1996-2003	----	Case study: Analysis of costsfollowing the Ontario system restructuring	5% of cost increases due to the loss of economies of integration (scale and scope)
Fraquelli et al (2005)	25 Italian municipal utilities1994-2000 (14 vertically integrated, 11 distribution only)	$C_6 = f(Y_1, Y_{12}, w^l, w_2^i, Z_{10}, Z_{25}, t)$	Composite Cost Function NLSUR	3% for the average firm (G: 300 and D=600) Other hedonic characteristics (Z) are
Arocena (2008)	12 Spanish utilities 1989-1997	$C_2 = f(Y_4, Y_5, Y_{13}, Y_{17}, Y_{18}, Z_{28})$	Non parametric cost frontier. Data Envelopment Analysis	Cost and quality gains from vertical integration (between 1.1%-4.9%) and horizontal integration (1.3%-4.3%)
Greer (2008)	831 US rural electric cooperatives 1997	$C_7 = f(Y_{15}, Y_{16}, w^{k*}, w^l, w_1^p, Z_{10}, Z_{16})$	Modified quadratic cost function.	Substantial cost savings from vertical integration of rural cooperatives (above 40% associated at the sample mean, G: 320 GWH D: 300 GWH

C_1 = Total utility operating expenses
C_2 = O&M expenses + imputed capital expenditures – costs of purchased power
C_3 = Total costs excluding sales, consumers accounts and administration costs.
C_4 = Total cost of electric supply (including the cost of purchased and generated power)
C_5 = The sum of labor, capital and fuel expenses
C_6 = The sum of labor and other inputs (defined as the sum of depreciation, maintenance, materials and services, but excluding the costs of purchased power)
C_7 = Operating expenses + interest on long-term debt

Y_1= Net generation (MWHs)
Y_2= Power generated by fossil fuel plants (MWHs)
Y_3= Power generated by nuclear plants (MWHs)
Y_4= Power generated by hydro plants (MWHs)
Y_5= Power generated by thermal plants (including fossil fuel and nuclear)
Y_6= Power generated from coal
Y_7= Power generated from oil&gas
Y_8= Circuit-voltage miles
Y_9= Index of interconnected activity (Interchange + wheeling power /Average power exchange)
Y_{10}= Circuit-voltage miles * Number of Contracts
Y_{11} =Percentage of total sales to ultimate consumers
Y_{12}= Power distributed to final consumers (MWHs)
Y_{13}= Number of ultimate consumers
Y_{14}= Sales for resale plus ultimate sales (MWHs)
Y_{15}= Electricity distributed to residential and small commercial customers (MWHs)
Y_{16}= Electricity distributed to industrial and large commercial customers (MWHs)
Y_{17}= High voltage distributed power
Y_{18}= Low voltage distributed power

X_1 = Capital stock of generation
X_2 = Capital stock in transmission
X_3 = Capital stock in distribution
X_4 = Labor used in generation
X_5 = Labor used in distribution
X_6 = Fuel used in generation

w^l = Price of labor ($/worker)
$w^k{}_1$= Price of capital (WACC of common stock, preferred stock and long-term debt)
$w^k{}_2$= Price of capital (interest on LTD/LTD)
$w^k{}_3$= Price of capital (yield to maturity on long-term bonds)
$w^k{}_4$= Price of capital (Cost of capital/net generation)
$w^k{}_5$= Price of capital ((Depreciation + Rate of Return*Equity)/Tangible fixed assets)
$w^k{}_6$= Divisia price index constructed from individual capital service prices calculated for each asset class
$w^k{}_7$= Price of capital (ida and kuwahara)

$w^f{}_1$= Fuel price (fuel costs/million BTUs)
$w^f{}_2$ = Fuel price (weighted average cost of steam and nuclear fuel per MWh of generation)
$w^f{}_3$= Fuel price (Cost of fossil fuels/Power generated from fossil fuels)
$w^f{}_4$= Fuel price (Total fuel expenses/Heat consumption of conversion into heavy oil)
$w^p{}_1$= Price of purchased power (cost of purchased power/total MWh)
$w^p{}_2$= Price of electricity procurement = weighted average price of purchased and own-generated power.
$w^p{}_3$= Price of generated electricity
$w^i{}_1$= Price of other inputs (Expenditures in intermediate inputs/Net revenues)
$w^i{}_2$= Price of other inputs ((Depreciation+Maintenance+Materials+Services)/Sum of generated and distributed power))

Z_1= Square miles of service territory
Z_2= Regional dummy (census region)
Z_3= Regional dummy (South, Southwest, Northeast)
Z_4= Percentage of residential and industrial customers
Z_5= Percentage of nuclear capacity
Z_6= Percentage of gas capacity
Z_7= Percentage of hydro capacity
Z_8= Density (number of distribution meters per square mile of service territory)
Z_9= Customer density (number of customers per square mile)
Z_{10}= Customer density (number of customers per distribution mile)
Z_{11}= Percentage of utilization of generating capacity
Z_{12}= Percentage of sales to ultimate consumers
Z_{13}= Percentage of sales to residential consumers
Z_{14}= Percentage of high voltage sold
Z_{15}= Average usage per customer class
Z_{16}= Miles of transmission line
Z_{17}= Number of distribution line transformers
Z_{18}= Dummy variable for holding company
Z_{19}= Dummy for power pool membership
Z_{20}= Heating plus cooling degree days in the principal city served by the utility
Z_{21}= Share of underground distribution lines
Z_{22}= Percentage of underground distribution expenses
Z_{23}= Generation dummy
Z_{24}= Distribution dummy
Z_{25}= Firm size dummies (small, medium, large)
Z_{26}= Number of customers
Z_{27}= Technology index in transmission and distribution = line losses/delivered electricity
Z_{28}= Quality of service (interruptions of supply)
Z_{29}= Firm specific dummies

t = time trend
* Not detailed

TABLE 2. Sample descriptive statistics

Variable	Mean	Std.Dev.	Minimum	Maximum
Outputs				
D1-Distribution Mwh (000) (Full Service+Dist.Only)	16,890	19,861	0	102,526
D2-Distribution Customers (000) (Full Service+Dist. Only)	619	762	0	4,474
G- Generation Mwh (000)	14,580	18,878	0	85,827
G1-Fossil Fuel Generation Mwh (000)	11,294	14,159	0	67,504
G2- Nuclear Generation Mwh (000)	2,921	6,212	0	38,254
G3- Hydro Generation Mwh (000)	365	931	0	5,638
Costs				
TC - Total Costs (millions)	770.7	943.7	4.2	5,160.5
KC - Capital Costs (millions)	266.3	342.7	1.2	1,981.6
FC - Total Fuel Costs (millions)	241.7	353.6	0.0	2,250.8
F1C -Conventional Fuel Costs (millions)	227.9	336.3	0.0	2,152.6
F2C - Nuclear Fuel Costs (millions)	13.7	29.0	0.0	171.8
LC - Labour Costs (millions)	91.3	123.0	0.3	641.0
OC - Other Costs (millions)	171.4	193.2	1.9	932.5
DC - Distribution Costs (millions)	240.6	297.4	0.0	1,676.6
GC - Generation Costs (millions)	530.1	714.1	0.0	4,141.3
Input Prices				
K - Capital Price (per $)	0.142	0.010	0.128	0.231
F - Total Fuel Price (per million BTU)	1.81	1.12	0.40	8.19
F1 - Conventional Fuel Price (per million BTU)	2.20	1.25	0.53	8.19
F2 - Nuclear Fuel Price (per million BTU)	0.44	0.03	0.34	0.56
L - Labour Price (census)	65,761	8,081	45,283	85,437
O - Other Costs Price Deflator	1.00	0.16	0.73	1.63
Input Quantities				
XK - Capital Stock ($) (millions)	1,864.8	2,373.1	8.6	14,084.8
XF - Total Fuel (billions of BTU)	148,509	192,921	0	937,501
XF1 - Conventional Fuel (billions of BTU)	117,286	146,414	0	745,759
XF2 - Nuclear Fuel (billions of BTU)	31,222	66,826	0	408,254
XL - Employees	1,385	1,832	4	10,163
Operating Characteristics and Dummy Variables				
RESDENS - Dist. Mwh per Residential Customer	9.80	3.75	-	16.77
NRESDENS - Dist. Mwh per Nonresidential Customer	134.28	62.35	-	372.61
DENSITY - D2/Total Network Length	34.71	24.06	-	175.82
DSHRFULL - Full Service Customers/D2	0.91	0.25	-	1.00
OHSHARE - Overhead Lines/Total Network Length	0.66	0.31	-	1.00
LOADFACT - Avg. Hourly Demand/Peak Hourly Demand	0.50	0.15	-	0.78
SYSTEMUT -G/Generation Capacity	44.67	25.84	-	89.99
FOSSILS- Fossil Fuel Generation Dummy	0.75	0.43	-	1.00
NUKES - Nuclear Fuel Generation Dummy	0.33	0.47	-	1.00
HYDROS - Hydro Fuel Generation Dummy	0.39	0.49	-	1.00
DISTS - Distribution Dummy	0.94	0.24	-	1.00
(116 observations)				

TABLE 3. Sample averages by firm type

Variable	Full Sample	All Integ. Firms	Integ. with G1,G2,& G3	Integ. with G1 & G2	Integ. with G1 & G3	Integ. with G1	Integ. with G2	Integ. with G3	Gen. Only Firms	Dist. Only Firms
Outputs										
D1-Distribution Mwh (000) (Full Service+Dist.Only)	16,890	20,307	32,714	42,794	14,870	9,994	7,174	645	0	8,199
D2-Distribution Customers (000) (Full Service+Dist. Only)	619	734	1,201	1,559	506	336	573	22	0	343
G- Generation Mwh (000)	14,580	18,903	31,898	33,928	14,691	9,953	3,288	174	3,978	0
G1-Fossil Fuel Generation Mwh (000)	11,294	14,742	20,622	24,980	13,765	9,953	0	0	1,836	0
G2- Nuclear Generation Mwh (000)	2,921	3,690	10,244	8,948	0	0	3,288	0	2,013	0
G3- Hydro Generation Mwh (000)	365	471	1,033	0	926	0	0	174	130	0
Costs										
TC - Total Costs (millions)	770.7	963.5	1,557.8	2,128.0	628.1	487.9	349.8	14.3	147.4	169.4
KC - Capital Costs (millions)	266.3	326.7	574.4	711.9	212.6	137.0	116.7	5.7	62.6	81.0
FC - Total Fuel Costs (millions)	241.7	315.8	390.5	835.2	211.8	205.2	14.7	0.0	32.1	0.0
F1C -Conventional Fuel Costs (millions)	227.9	298.5	341.4	795.4	211.8	205.2	0.0	0.0	23.7	0.0
F2C - Nuclear Fuel Costs (millions)	13.7	17.3	49.1	39.8	0.0	0.0	14.7	0.0	8.4	0.0
LC - Labour Costs (millions)	91.3	113.2	222.0	198.9	70.6	48.7	38.5	3.6	16.3	24.8
OC - Other Costs (millions)	171.4	207.9	370.9	381.9	133.2	97.1	179.9	5.0	36.4	63.6
DC - Distribution Costs (millions)	240.6	276.8	472.0	571.9	184.4	120.2	236.3	9.3	0.0	169.4
GC - Generation Costs (millions)	530.1	686.8	1,085.8	1,556.1	443.8	367.7	113.5	4.9	147.4	0.0
Input Prices										
K - Capital Price (per $)	0.142	0.142	0.145	0.145	0.139	0.139	0.142	0.149	0.160	0.139
F - Total Fuel Price (per million BTU)	1.81	1.89	1.19	2.16	2.10	2.29	0.43	1.83	1.14	1.83
F1 - Conventional Fuel Price (per million BTU)	2.20	2.25	1.63	3.83	2.10	2.29	2.20	2.20	2.41	2.20
F2 - Nuclear Fuel Price (per million BTU)	0.44	0.44	0.45	0.42	0.44	0.44	0.43	0.44	0.43	0.44
L - Labour Price (census)	65,761	64,775	66,167	65,359	63,706	63,168	75,307	69,534	65,169	70,089
O - Other Costs Price Deflator	1.00	0.97	1.01	1.00	0.96	0.92	1.18	1.09	0.96	1.12
Input Quantities										
XK - Capital Stock ($) (millions)	1,864.8	2,284.9	3,967.8	4,928.5	1,528.3	982.0	822.9	38.1	409.8	589.1
XF - Total Fuel (billions of BTU)	148,509	191,910	323,682	358,193	141,600	101,527	34,751	0	38,747	0
XF1 - Conventional Fuel (billions of BTU)	117,286	152,420	213,519	263,462	141,600	101,527	0	0	17,796	0
XF2 - Nuclear Fuel (billions of BTU)	31,222	39,490	110,163	94,731	0	0	34,751	0	20,951	0
XL - Employees	1,385	1,723	3,323	2,987	1,111	780	476	52	263	340
Operating Characteristics and Dummy Variables										
RESDENS - Dist. Mwh per Residential Customer	9.80	10.81	10.34	11.49	10.55	11.51	7.10	8.46	-	8.83
NRESDENS - Dist. Mwh per Nonresidential Customer	134.28	145.69	145.35	160.03	146.44	144.90	106.14	139.14	-	131.21
DENSITY - D2/Total Network Length	34.71	37.38	30.18	40.97	39.42	37.84	65.46	19.95	-	35.13
DSHRFULL - Full Service Customers/D2	0.91	0.98	0.974	0.974	0.987	0.997	0.916	1.000	-	0.916
OHSHARE - Overhead Lines/Total Network Length	0.66	0.69	0.67	0.72	0.72	0.67	0.78	0.82	-	0.76
LOADFACT - Avg. Hourly Demand/Peak Hourly Demand	0.50	0.53	0.51	0.54	0.58	0.51	0.46	0.56	-	0.56
SYSTEMUT -G/Generation Capacity	44.67	53.62	55.91	50.92	50.35	53.22	70.32	58.38	66.09	-
FOSSILS- Fossil Fuel Generation Dummy	0.75	0.95	1.00	1.00	1.00	1.00	-	-	0.43	-
NUKES - Nuclear Fuel Generation Dummy	0.33	0.40	1.00	1.00	-	-	1.00	-	0.43	-
HYDROS - Hydro Fuel Generation Dummy	0.39	0.49	1.00	-	1.00	-	-	1.00	0.29	-
DISTS - Distribution Dummy	0.94	1.00	1.00	1.00	1.00	1.00	1.00	1.00	-	1.00
Observations	116	88	22	10	20	32	3	1	7	21

TABLE 4. Model selection tests

Model Log Likelihood Function Values

Model number:	**(i)**	**(ii)**	**(iii)**	**(iv)**	**(v)**	**(vi)**
Fuel prices:	**F1,F2**	**F1,F2**	**F**	**F**	**F**	**F**
Distribution outputs:	**D2**	**D1**	**D2**	**D1**	**D2**	**D1**
Generation outputs:	**G1,G2,G3**	**G1,G2,G3**	**G1,G2,G3**	**G1,G2,G3**	**G**	**G**
(1) Base Cost Function Model	-9,470.42	-9,480.11	-7,667.60	-7,676.17	-7,755.48	-7,755.69
(2) Regional Dummies	-9,456.18	-9,468.03	-7,658.67	-7,668.43	-7,743.40	-7,746.06
(3) Regional dummies, and 7 operating characteristics	-9,455.37	-9,463.43	-7,657.79	-7,664.15	-7,742.17	-7,743.64
Number of parameters in base cost function models	45	45	36	36	21	21

LR Test Statistics for Restrictions Involving operating characteristics

		(i)	(ii)	(iii)	(iv)	(v)	(vi)
Restriction of (3) to (2)	(d.f.:7)	1.62	9.20	1.77	8.56	2.47	4.83
Restriction of (2) to (1)	(d.f.:9)	***28.49***	***24.17***	***17.85***	**15.47**	***24.16***	***19.26***

LR Test Statistics for Restrictions Involving Output Variables

	Restrictions	
	(iii) vs (v) (d.f.:15)	**(iv) vs (vi)** (d.f.:15)
(1) Base Cost Function Model	***175.77***	***159.05***
(2) Regional Dummies	***169.46***	***155.25***
(3) Regional dummies, and 7 operating characteristics	***168.77***	***158.98***

LR Test Statistics for Restriction of a Two Fuel Specification to a Single Fuel Specification

	Restricted Specification	
	(i) (d.f.:9)	**(ii)** (d.f.:9)
(1) Base Cost Function Model	***796.71***	***749.31***
(2) Regional Dummies	***784.17***	***725.47***
(3) Regional dummies, and 7 operating characteristics	***756.98***	***731.46***

Note: Test statistics in **bold** (***bold italic***) are significant at 0.10 (0.05) level

TABLE 5. Estimates for the sample average firm in the alternative models

Model number:	(i)	(ii)	(iii)	(iv)	(v)	(vi)
Fuel prices:	**F1,F2**	**F1,F2**	**F**	**F**	**F**	**F**
Distribution outputs:	**D2**	**D1**	**D2**	**D1**	**D2**	**D1**
Generation outputs:	**G1,G2,G3**	**G1,G2,G3**	**G1,G2,G3**	**G1,G2,G3**	**G**	**G**
Cost Elasticities						
G- Total Generation (Mwh)					***0.709***	***0.551***
G1- Fossil Fuel Generation (Mwh)	***0.553***	***0.409***	***0.494***	***0.347***		
G2- Nuclear Generation (Mwh)	***0.138***	***0.113***	***0.194***	***0.169***		
G3- Hydro Generation (Mwh)	0.012	0.007	0.013	0.010		
D1 - Distribution Units Delivered (Mwh)		***0.441***		***0.453***		***0.442***
D2 - Distribution Customers	***0.263***		***0.276***		***0.281***	
Economies of Scale						
global	**1.035**	1.031	1.024	1.021	1.010	1.008
in generation	***0.953***	***0.911***	***0.954***	***0.926***	***0.966***	***0.919***
in distribution	***0.948***	0.980	***0.944***	0.995	***0.968***	***0.899***
in the absence of vertical scope economies	***0.952***	***0.942***	***0.951***	0.958	***0.967***	***0.910***
Scope Economies						
Vertical - between distribution and generation	***0.081***	***0.086***	***0.071***	**0.062**	**0.043**	***0.097***
Total Horizontal - in generation	0.054	0.051	0.035	0.034	-	-
Global	***0.135***	***0.137***	**0.106**	0.096	-	-
Cost Estimates ($ millions)						
Total Costs	***800.8***	***805.2***	***799.7***	***806.2***	***802.8***	***803.0***
Generation Only Costs	***600.9***	***457.0***	***591.3***	***442.7***	***584.4***	***484.3***
Distribution Only Costs	***264.6***	***417.2***	***265.3***	***413.5***	***252.6***	***396.5***
Vertical Scope Economy Savings	***64.7***	***69.0***	***56.9***	**50.0**	**34.2**	***77.8***
Horizontal Scope Economy Savings	43.5	41.4	27.7	27.0	-	-
Global Scope Economy Savings	***108.2***	***110.4***	**84.6**	77.0	-	-

Note: Estimates in **bold** (***bold italic***) are significantly different from zero at 0.10 (0.05) level, except for economies of scale estimates which are statistically different from 1 at these levels

TABLE 6 - Disaggregated Horizontal Scope Economy Estimates for the Sample Average Firm (millions of dollars)

Type of horizontal separation	Unbundled versus integrated generation costs	Cost Savings From Horizontal Integration	Savings Relative to Fully Integrated Cost
G3 and G1,G2	C(G1,G2,0,0) + C(0,0,G3,0) - C(G1,G2,G3,0)	***33.20***	***0.041***
G2 and G1	C(G1,0,0,0) + C(0,G2,0,0) - C(G1,G2,0,0)	10.26	0.013
G2 and G1,G3	C(G1,0,G3,0) + C(0,G2,0,0) - C(G1,G2,G3,0)	8.66	0.011
G3 and G1	C(G1,0,0,0) + C(0,0,G3,0) - C(G1,0,G3,0)	***34.80***	***0.043***
G1and G2,G3	C(0,G2,G3,0) + C(G1,0,0,0) - C(G1,G2,G3,0)	14.79	0.018
G2 and G3	C(0,G2,0,0) + C(0,0,G3,0) - C(0,G2,G3,0)	**28.67**	**0.036**

Note: Estimates in **bold** (***bold italic***) are significantly different from zero at 0.10 (0.05) level.

TABLE 7. Estimated costs of the average firm's output in alternative configurations (millions of dollars)

Partition No	Structural configuration	Estimated Cost	Excess Relative to Fully Integrated Costs	Excess Cost/Fully Integrated Costs
	Fully Integrated			
	C(G1,G2,G3,D2)	***800.8***	-	-
	Vertical Integration with Two Types of Generation			
1	C(G1,G2,0,D2)+C(0,0,G3,0)	***825.3***	24.5	0.031
2	C(0,G2,G3,D2)+C(G1,0,0,0,0)	***831.9***	**31.2**	**0.039**
3	C(G1,0,G3,D2)+C(0,G2,0,0)	***836.2***	***35.2***	***0.044***
	Vertical Integration with One Type of Generation			
4	C(0,G2,0,D2)+C(G1,0,G3,0)	***817.2***	16.4	0.020
5	C(G1,0,0,D2)+C(0,G2,G3,0)	***833.7***	**32.9**	**0.041**
6	C(0,G2,0,D2)+C(G1,0,0,0)+C(0,0,G3,0)	***851.9***	51.2	0.064
7	C(G1,0,0,D2)+C(0,G2,0,0)+C(0,0,G3,0)	***862.4***	**61.6**	**0.077**
8	C(0,0,G3,D2)+C(G1,G2,0,0)	***877.1***	***76.3***	***0.095***
9	C(0,0,G3,D2)+C(G1,0,0,0)+C(0,G2,0,0)	***887.4***	***86.6***	***0.108***
	Vertically Separated but Fully Horizontally Integrated			
10	C(0,0,0,D2)+C(G1,G2,G3,0)	***865.5***	***64.7***	***0.081***
	Vertically Separated with Partial Horizontal Integration			
11	C(0,0,0,D2)+C(0,G2,0,0)+C(G1,0,G3,0)	***874.2***	***73.4***	***0.092***
12	C(0,0,0,D2)+C(G1,0,0,0)+C(0,G2,G3)	***880.3***	***79.5***	***0.099***
13	C(0,0,0,D2)+C(0,0,G3,0)+C(G1,G2,0)	***898.7***	***97.9***	***0.122***
	Vertically Separated with Full Horizontal Disintegration			
14	C(0,0,0,D2)+C(G1,0,0,0)+C(0,G2,0,0)+C(0,0,G3,0)	***909.0***	***108.2***	***0.135***

Note: Estimates in **bold** (***bold italic***) are significant at 0.10 (0.05) level

TABLE 8 - Scope Economy Estimates Rescaling the Average Firm and Holding Generation Shares Equal to those of the Sample Average Firm.

Panel A. Global scope economies

	G - assuming sample average firm's generartion shares shG1=0.775, shG2=0.20, shG3=0.025											
D2	3.64	7.29	10.93	14.58	18.22	21.87	25.51	29.16	32.80	36.45	40.09	43.74
154.8	0.413	0.251	0.174	0.127	0.094	0.069	0.048	0.031	0.017	0.004	-0.008	-0.019
309.6	0.338	0.229	0.170	0.130	0.101	0.079	0.060	0.044	0.029	0.017	0.005	-0.006
464.4	0.287	0.212	0.166	0.133	0.108	0.088	0.070	0.055	0.042	0.029	0.018	0.007
619.2	0.250	0.197	0.162	0.135	0.114	0.096	0.080	0.066	0.053	0.041	0.030	0.020
773.9	0.222	0.185	0.158	0.137	0.119	0.103	0.089	0.076	0.064	0.053	0.042	0.032
928.7	0.199	0.175	0.155	0.138	0.123	0.109	0.097	0.085	0.074	0.063	0.053	0.044
1,083.5	0.181	0.166	0.152	0.139	0.127	0.115	0.104	0.094	0.083	0.074	0.064	0.055
1,238.3	0.167	0.158	0.149	0.139	0.130	0.120	0.111	0.102	0.092	0.083	0.075	0.066
1,393.1	0.154	0.151	0.146	0.140	0.133	0.125	0.117	0.109	0.101	0.093	0.084	0.076
1,547.9	0.144	0.145	0.144	0.140	0.135	0.129	0.123	0.116	0.109	0.101	0.094	0.086
1,702.7	0.135	0.140	0.141	0.140	0.137	0.133	0.128	0.122	0.116	0.110	0.103	0.096
1,857.5	0.127	0.135	0.139	0.140	0.139	0.136	0.133	0.128	0.123	0.117	0.111	0.105

Panel B. Vertical scope economies

	G - assuming sample average firm's generartion shares shG1=0.775, shG2=0.20, shG3=0.025											
D2	3.64	7.29	10.93	14.58	18.22	21.87	25.51	29.16	32.80	36.45	40.09	43.74
154.8	0.146	0.096	0.073	0.060	0.051	0.045	0.041	0.038	0.035	0.033	0.031	0.029
309.6	0.124	0.094	0.078	0.068	0.061	0.056	0.053	0.050	0.047	0.045	0.043	0.042
464.4	0.110	0.092	0.082	0.075	0.070	0.066	0.063	0.061	0.059	0.057	0.055	0.054
619.2	0.099	0.090	0.085	0.081	0.078	0.075	0.073	0.071	0.070	0.068	0.067	0.066
773.9	0.090	0.089	0.087	0.086	0.085	0.083	0.082	0.081	0.080	0.079	0.078	0.077
928.7	0.084	0.087	0.089	0.090	0.091	0.091	0.091	0.090	0.090	0.089	0.089	0.088
1,083.5	0.079	0.086	0.091	0.094	0.096	0.097	0.098	0.099	0.099	0.099	0.099	0.098
1,238.3	0.074	0.085	0.092	0.097	0.101	0.103	0.105	0.107	0.107	0.108	0.108	0.109
1,393.1	0.070	0.083	0.093	0.100	0.105	0.109	0.112	0.114	0.116	0.117	0.118	0.118
1,547.9	0.067	0.082	0.093	0.102	0.109	0.114	0.118	0.121	0.123	0.125	0.126	0.127
1,702.7	0.064	0.081	0.094	0.104	0.112	0.118	0.123	0.127	0.130	0.133	0.134	0.136
1,857.5	0.062	0.080	0.094	0.106	0.115	0.122	0.128	0.133	0.137	0.140	0.142	0.144

Panel C. Horizontal scope economies

	G - assuming sample average firm's generartion shares shG1=0.775, shG2=0.20, shG3=0.025											
D2	3.64	7.29	10.93	14.58	18.22	21.87	25.51	29.16	32.80	36.45	40.09	43.74
154.8	0.267	0.156	0.101	0.067	0.042	0.023	0.007	-0.006	-0.018	-0.029	-0.039	-0.048
309.6	0.214	0.136	0.092	0.062	0.040	0.022	0.007	-0.006	-0.018	-0.028	-0.038	-0.047
464.4	0.177	0.120	0.084	0.058	0.038	0.021	0.007	-0.006	-0.017	-0.028	-0.038	-0.047
619.2	0.151	0.107	0.077	0.054	0.036	0.020	0.007	-0.006	-0.017	-0.027	-0.037	-0.046
773.9	0.131	0.096	0.071	0.051	0.034	0.019	0.006	-0.005	-0.016	-0.026	-0.036	-0.045
928.7	0.116	0.088	0.066	0.048	0.032	0.019	0.006	-0.005	-0.016	-0.026	-0.035	-0.044
1,083.5	0.103	0.080	0.061	0.045	0.031	0.018	0.006	-0.005	-0.015	-0.025	-0.035	-0.043
1,238.3	0.093	0.074	0.057	0.042	0.029	0.017	0.006	-0.005	-0.015	-0.025	-0.034	-0.043
1,393.1	0.084	0.068	0.053	0.040	0.028	0.016	0.006	-0.005	-0.015	-0.024	-0.033	-0.042
1,547.9	0.077	0.063	0.050	0.038	0.027	0.016	0.005	-0.005	-0.014	-0.023	-0.032	-0.041
1,702.7	0.071	0.059	0.047	0.036	0.025	0.015	0.005	-0.004	-0.014	-0.023	-0.032	-0.040
1,857.5	0.065	0.055	0.044	0.034	0.024	0.015	0.005	-0.004	-0.013	-0.022	-0.031	-0.039

Note: Each element of the matrices indicates the scope economy estimate for production equivalent to the total generation and distribution outputs respectively associated with each column and row.

TABLE 9. Scope Economies with Sample Avg. Generation and Distribution but With Alternative Generation Shares

Panel A. Global scope economies

	shg3							
shg2	0.0125	0.025	0.0375	0.050	0.0625	0.075	0.0875	0.100
0.10	0.136	0.133	0.131	0.128	0.126	0.123	0.120	0.117
0.20	0.138	0.135	0.132	0.128	0.125	0.121	0.118	**0.114**
0.30	0.144	0.140	0.136	0.132	0.128	0.124	0.119	0.114
0.40	0.154	0.150	0.145	0.140	0.135	0.130	0.124	0.119
0.50	0.168	0.163	0.157	0.151	0.145	0.139	0.133	0.127
0.60	0.186	0.180	0.173	0.167	0.160	0.153	0.146	0.139
0.70	0.209	0.202	0.195	0.187	0.179	0.171	0.163	0.155
0.80	0.238	0.229	0.221	0.212	0.203	0.194	0.185	0.176
0.90	*0.272*	0.262	0.253	0.243	0.233	0.223	0.212	0.202

Panel B. Vertical scope economies

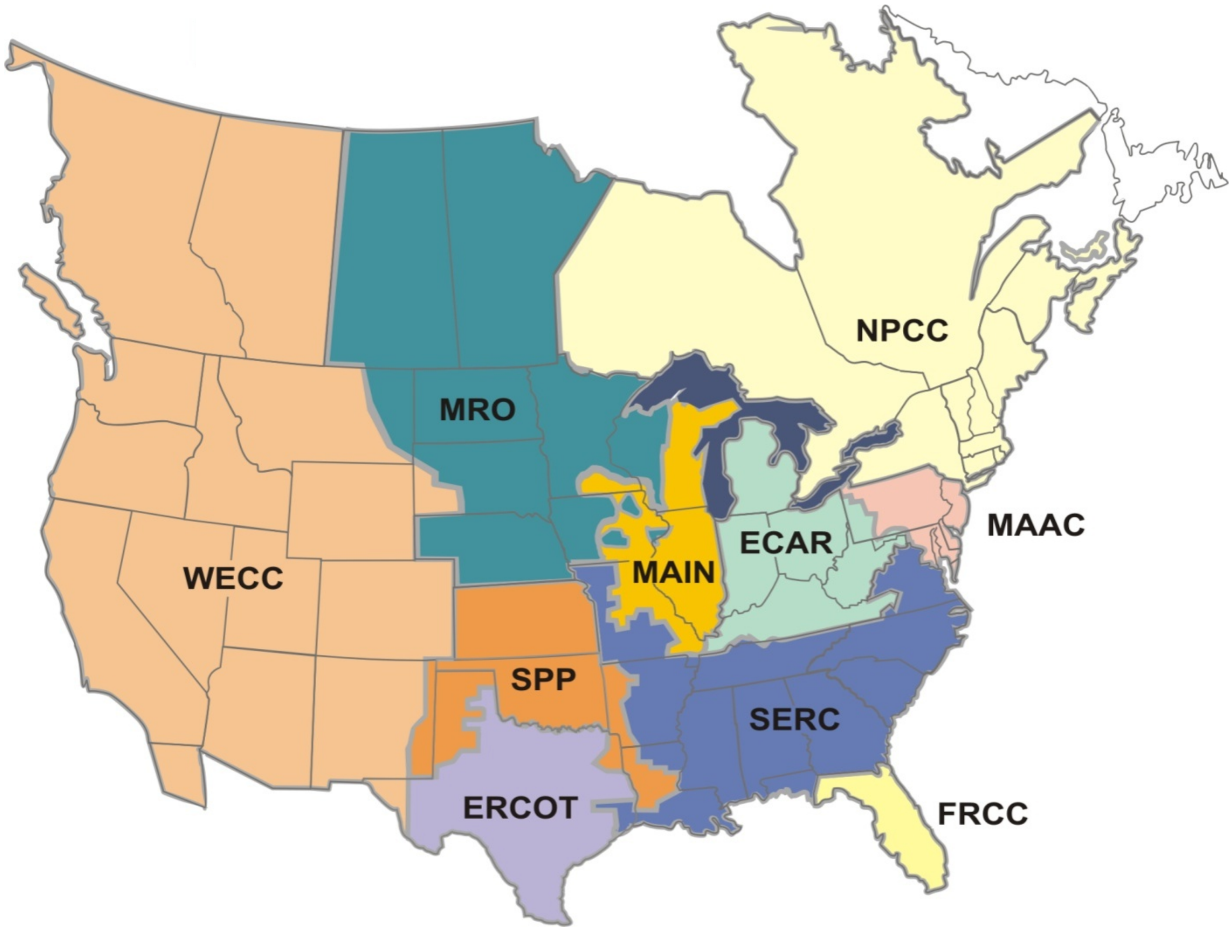
	shg3							
shg2	0.0125	0.025	0.0375	0.050	0.0625	0.075	0.0875	0.100
0.10	0.072	0.067	0.061	0.056	0.050	0.044	0.039	**0.033**
0.20	0.086	0.081	0.075	0.070	0.064	0.059	0.053	0.047
0.30	0.101	0.095	0.090	0.084	0.079	0.073	0.067	0.061
0.40	0.116	0.110	0.105	0.099	0.093	0.088	0.082	0.076
0.50	0.132	0.126	0.120	0.114	0.109	0.103	0.097	0.091
0.60	0.148	0.142	0.137	0.131	0.125	0.119	0.113	0.107
0.70	0.166	0.160	0.154	0.148	0.141	0.135	0.129	0.123
0.80	0.185	0.179	0.172	0.166	0.160	0.153	0.147	0.140
0.90	*0.206*	0.199	0.193	0.186	0.179	0.172	0.165	0.158

Panel C. Horizontal scope economies

	shg3							
shg2	0.0125	0.025	0.0375	0.050	0.0625	0.075	0.0875	0.100
0.10	0.064	0.067	0.070	0.073	0.076	0.078	0.081	*0.084*
0.20	0.052	0.054	0.057	0.059	0.061	0.063	0.065	0.067
0.30	0.043	0.045	0.047	0.048	0.049	0.051	0.052	0.053
0.40	0.038	0.039	0.040	0.041	0.041	0.042	0.042	0.043
0.50	0.036	0.037	0.037	0.037	0.037	0.037	0.036	0.036
0.60	0.038	0.038	0.037	0.036	0.036	0.035	0.034	**0.033**
0.70	0.043	0.042	0.041	0.039	0.038	0.036	0.034	0.033
0.80	0.052	0.050	0.048	0.046	0.044	0.041	0.039	0.036
0.90	0.066	0.063	0.060	0.057	0.054	0.050	0.047	0.043

Note: shg1= conventional generation share; shg2=nuclear generation share; shg3=hydro generation share. Each element of the matrices indicates the scope economy estimate for producing total output equivalent to the sample average firm's total generation and distribution output, but assuming this generation is produced with shg2 and shg3 as respectively indicated in each row and column and shg1 = 1- shg2 - shg3.

FIGURE 1. North American Electric Reliability Corporation (NERC) Regions: 2001



Western Electric Coordinating Council (WECC)	Midwest Reliability Organization (MRO)
Southeastern Electric Reliability Council (SERC)	Southwest Power Pool (SPP)
Northeast Power Coordinating Council (NPCC)	Mid-America Interconnected Network (MAIN)
Electric Reliability Council of Texas (ERCOT)	Mid-Atlantic Area Council (MAAC)
East Central Area Reliability Council (ECAR)	Florida Reliability Coordinating Council (FRCC)

Appendix Table - Parameter estimates for the preferred specification (Model i)

Variable	Coef.	Std. Err.	Variable	Coef.	Std. Err.
constant	***800,794,000***	12,690,200	**Input Prices and Interactions**		
Regional Dummies			BK	***1,853,540,000***	64,820,000
BWECC	***60,965,000***	16,356,700	BL	***1,383***	56
BMRO	21,361,900	18,466,800	BF1	***116,405,000***	965,329
BERCOT	13,831,500	21,077,200	BF2	***31,232,000***	150,933
BSERC	***53,486,200***	17,497,800			
BFRCC	16,128,600	24,028,600	BKK	***- 5,092,320,000***	1,974,250,000
BNPCC	**30,081,200**	17,727,500	BF1F1	***-1,256,710***	578,906
BMAIN	16,538,200	17,636,800	BF2F2	-1,837,590	2,912,910
BECAR	***60,396,600***	14,742,300	BLL	***- 0.021***	0.009
BMAAC	**42,870,900**	21,965,300			
			BF1K	***67,725,300***	22,778,000
Outputs and Output Interactions			BF2K	545,838	9,375,390
BG1	***39.22***	1.35	BKL	2,134.02	2,611.28
BG2	***37.70***	2.84	BF1L	-20.89	37.82
BG3	25.96	18.96	BF2L	8.66	27.41
BD2	***340.62***	27.58	BF1F2	-45,909.46	108,358.44
			Input Price and Output Interactions		
BG1G1	***0.00000016***	0.00000006	BG1K	***62.58***	6.22
BG2G2	-0.00000020	0.00000021	BF1G1	***10.26***	0.09
BG3G3	0.00000065	0.00000597	BF2G1	-0.012247	0.01533
BD2D2	***0.00005738***	0.00002363	BG1L	***0.000039***	0.000006
BG1G2	***0.00000061***	0.00000012	BG2K	***93.72***	14.28
BG1G3	***-0.00000110***	0.00000035	BG2L	***0.00011***	0.00001
BG2G3	0.00000150	0.00000109	BF1G2	-0.026	0.215
			BF2G2	***10.664***	0.035
BD2G1	***- 0.00000234***	0.00000079			
BD2G2	***-0.00001480***	0.00000300	BG3K	***155.81***	77.78
BD2G3	***0.00003832***	0.00000972	BG3L	***0.00024***	0.00007
			BF1G3	- 1.35	1.17
			BF2G3	***0.71***	0.18
			BD2K	***1,364.41***	126.93
			BF1D2	1.238	1.838
			BF2D2	***0.798***	0.327
			BD2L	***0.0008***	0.0001
				Log-Likelihood	-9,456.18

Note: Parameters in **bold** (***bold italic***) are significant at 0.10 (0.05) level.