Do Mergers Really Increase Efficiency?

A Cost Efficiency Analysis of Electricity Distributors in the US

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February, 2007

Paper prepared for Verein für Socialpolitik, Jahrestagung 2007

Abstract

In the mid-1990s, the US domestic electricity industry underwent substantial changes that resulted in 70 mergers by 2002. It is frequently said that mergers increase efficiency by exploiting the parties' economies of scale and scope. Our paper tests this commonly held belief by applying parametric Stochastic Frontier Analysis (SFA) to a panel dataset of US electricity distributors to estimate both cost efficiencies and merger effects on efficiency simultaneously. Our findings indicate that horizontal mergers do result in an efficiency shift from the target firm to the buyer, but that efficiency shift does only result partly from reaping scale economies.

Keywords: Mergers and acquisitions (M&A), cost efficiency, Stochastic Frontier Analysis (SFA), electricity distribution, US

JEL Code: C23, L43, L94

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The author thanks the participants of the 5th Conference on Applied Infrastructure Research (INFRADAY), 6 October 2006, TU Berlin, and of the Doctoral Seminar, 6 November 2006, TU Dresden, for useful suggestions and comments. Particular thanks go to Jan Abrell, Jean-Michel Glachant, Christian von Hirschhausen, Gerhard Kempkes, Yannick Perez, Carsten Pohl, Spiro Stefanou, and Loren Tauer for their discussion and support of this paper. The usual disclaimer applies.

1 INTRODUCTION

Beginning in the mid-1990s, the US experienced a substantial merger[1] wave in the electricity industry that resulted in more than 70 mergers with a combined value of 180 billion dollars (US) from 1994-2002 (Edison Electric Institute, cited in Kwoka and Pollitt 2005, p. 33). During the same period, the European Union experienced its own electricity industry consolidation.[2]

However, the analyses of electricity industry mergers in any nation correspond strongly to industrial organization because the models encourage antitrust agencies to assess the anticompetitive effects of a decreasing number of firms. Farrell and Shapiro (1990) analyzed the welfare effects of horizontal mergers in a Cournot setting and found that under some circumstances the anticompetitive effect can be compensated somewhat by the cost savings from learning effects or from the savings generated by economies of scale. Thus, mergers are welfare enhancing if the efficiency gain at least cancels out the anticompetitive effect. Although this argument for merging is well established in theory, the evidence to date is scarce.

An overview of mergers and acquisition (M&A) and efficiency measures in the US was provided by Kwoka and Pollitt (2005) who reviewed three streams of relevant literature: (1) US electricity merger literature; (2) mergers and productivity literature; and (3) electricity distribution efficiency and productivity measurements. Within the field of benchmarking efficiency of US electricity distributors, there are two main applied techniques: the average-based, stochastic approach and the frontier-based, deterministic approach.

Kwoka (2005) used a dataset of 436 electricity distribution utilities in the US (117 investor owned utilities (IOUs) and 319 publicly owned utilities in 1989) to assess determinants of average costs and cost performance using Ordinary Least Squares (OLS) regression techniques. He found economies of scale with respect to the outputs electricity units delivered and the customer numbers, but the effects were minimal relative to the size of the service territory. As a result, economies of scope and

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[1] The term merger and acquisition (M&A) will be used in this paper equivalently, meaning that one firm (‘buyer’) is acquiring another firm (‘target’).

economies from vertical integration in the distribution business could not be stated. Kwoka concluded that a "positive" reason for mergers can only be found in the scale effects. In addition, his findings indicated that the systematic cost advantages of public utilities were 14% on average compared to IOUs.

Lowry, Getachew and Hovde (2005) assessed the average-based cost performance and efficiency of 66 US electricity distributors in 1991-2002 and applied Feasible Generalized Least Squares (FGLS). They used data from the Federal Energy Regulatory Commission (FERC) and modified it to control for the age of the investment. In addition to finding minimal scope effects, the authors highlighted the number of customers as the dominant cost driver and that the age of investment had a significant positive effect on costs. Over time the annual cost decreased by 0.6 percent to 0.8 percent depending on the specification chosen.

A frontier approach with the non-parametric technique Data Envelopment Analysis (DEA) was used by Nillesen, Pollitt and Keats (2001) and by Nilllesen and Pollitt (2001) to estimate technical efficiency scores for a cross-section dataset of over 130 US distributors in 1990. The first paper estimated the potential gains from three mergers by comparing pre-merger and post-merger potential cost savings, and the latter assessed the optimal customer base for a firm to achieve technical efficiency. Both papers suggested that M&A was a feasible instrument to increase a firm's efficiency.

Kwoka and Pollitt (2005) used DEA for estimating technical efficiency scores for US distributors and applied a two-stage procedure on FERC data for 78 IOUs from 1994-2001.[3] The results indicated that the acquired distributors were technically more efficient than the control-group of non-merging firms before consolidation, and that the buyers faced lower efficiency scores than the target firms. Post-merger, the authors found that the activities of merging parties were less efficient than those of the control firms. Thus, the merging parties did not appear to increase efficiency.

However, these applied techniques have some drawbacks. While the average-based techniques do not explicitly consider the boundaries of the cost or production function, the deterministic frontier approach does not regard stochastic errors. Additionally, the two-stage procedure used by Kwoka and

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[2] See Codognet et al. (2003) for a detailed survey of European M&A activities within the energy sector.

[3] Efficiency was calculated in a first stage; in a second stage, a Tobit regression was estimated to assess several merger effects on efficiency.

Pollitt is subject to an inconsistency problem (see Simar and Wilson (2007)). We will combine the advantages of both techniques in applying SFA to assess the effects of mergers on efficiency.

The remainder of this paper is structured as follows: the next section gives an overview of M&A activities in the US electricity industry. Section 3 describes the methodology, and Section 4 discusses the panel dataset and its sources. The empirical results are given in Section 6, and Section 7 offers conclusions and suggestions for future research.

2 MARKET CONSOLIDATION IN THE US ELECTRICITY INDUSTRY

Electricity restructuring in the US has been accompanied by M&A activity almost from its onset. This section provides a brief overview of the evolution of the industry structure and reviews the regulatory framework applicable to M&A.

2.1 Industry Structure and Regulation

Nowadays, the electricity industry in the US is characterized by a large number of market participants; approximately 5,000 in 1998. Generation is provided by utilities (IOUs, public power, and federal ownership) and independent power producers (IPPs) (EIA 1999, pp. 3-4). Approximately 200 IOUs accounted for 2/3 of total generation and capacity in 1998. The 3,000 electric utilities engaged in generation, transmission, and/or distribution hold a monopoly franchise over a specified geographic area and are subject to regulation by state and federal agencies.

The percentage of IPPs has risen over time through purchasing of generation assets due to the divesture activities of the IOUs; it rose from 12 to 36 percent in 1998-2004. Most IOUs were vertically integrated until the federal Energy Policy Act of 1992 and state legislation in the 1990s required divestiture of generation, transmission and distribution to foster wholesale and retail competition. In 2004, there were 28 registered electricity “top holding companies” (SEC 2006).

2.2 Merger Waves

Recent M&A activity follows a long tradition of concentration in the US electricity sector. The period 1917-1936 was the first “merger wave” and also the greatest consolidation process in the history of the sector with more than 200 mergers per year, peaking at over 300 mergers per year in the mid-1920s. As the nation's economy expanded, small operating companies formed holding companies to pool the engineering, operating, and financial resources needed to overcome technological difficulties and capital constraints (for example, large-scale interconnections). This first wave of merger activity ended because of widespread financial abuse, (Samuel Insull's empire – the precursor to Enron – is the most infamous example), and the federal government began to exert a regulatory hand: the assets of many holding companies were subject to reorganization and divestiture while the remaining holding companies were limited to a single integrated electricity system. More than 750 subsidiaries were spun off from the holding companies from 1935-1950 (EIA 1999, p. 11); after that, consolidation continued, but at a greatly reduced pace (Ray et al. 1992, pp. 5-7).

After 1965 when the IOUs assumed a dominant role in the consolidation process, 76 percent of the acquired companies joined an IOU (Ray et al. 1992, p. 8). The relative size of mergers grew also, leading to the "comfort level" that government, utilities, and financial analysts generally express about the mega-mergers of the present era (EIA 1999, p. 11). The third merger wave for the sector began in the mid-1990s, peaked in the late 1990s, and has recovered somewhat since 2005. See Appendix 1 for a table of the mergers approved by FERC and utilized for the purposes of calculation in this paper.

In summary, three major trends define M&A in the US electricity sector in the most recent wave:

(1) the increasing size of IOUs and their concentration of generation capacity;
(2) the disintegration of many vertically integrated IOUs into generation, transmission, and distribution;
(3) convergence – expanding IOUs formerly dedicated to electricity to include natural gas (EIA 1999, pp. 20-21, 29-30).

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It is important to note the contrasts between electric industry consolidation activity and what transpired historically throughout the US economy. Electricity sector M&A occurred chiefly in the second and third of the nation's four large merger waves (1892-1902, 1926-1930, 1966-1969, 1981-1986). Since the fourth wave, electricity sector consolidation activity has slowly decreased even as M&A within the national economy is expanding. These contrasts may suggest the existence of unique, industry-specific factors that encourage or discourage acquisitive behavior. We believe that state and federal policies regulating competition are such factors (Ray et al. 1992, pp.15-19).[4]

2.3 Rationales for M&A

The "drivers" for mergers and acquisitions are diverse. The work of Greer (1992) and Ray et al. (1992) discussed several causes, while Diamond and Edwards (1997)[5] identified the following five:

1. economic efficiency: in the form of cost savings by synergy effects[6]
2. defensive motives: increasing market value to guard against acquisition
3. diversification: in the form of investment risk diversity and smoothing business-cycle volatility (for non-electric acquisitions)
4. growth and personal aggrandizement: more expansion than required by exogenous demand; adding to the personal responsibilities of executive management or the CEO (Wilson 1996)
5. market power: increasing market share to reap larger monopoly/oligopoly profits.

Our paper employs the first rationale of economic efficiency because we focus specifically on M&A within the electricity distribution industry[7] and the efficiency development of the distributors in terms of their technical, cost and scale efficiencies. The quantitative methods we use are described in Section 3.

2.4 U.S. Regulatory Review

The policies that regulate industrial competition are generally concentrated within federal and state antitrust laws. The underlying philosophy developed with the enactment by the federal government of the Sherman Act of 1890 and the Clayton Act of 1914. The Sherman Act prohibits trusts and monopolies, as well as collusion in restraint of trade, while the Clayton Act prohibits mergers or other combinations (alliances and joint-ventures) that substantially reduce competition. Thus, the US

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[4] For example, in 2006, the proposed mega-merger between PSEG (New Jersey) and Exelon (Illinois) fell apart when the New Jersey Board of Public Utilities voted against it even though both FERC and the SEC had given their approvals.

[5] They followed the classification of Greer (1992) who related the utilities' M&A to the nature and pace of deregulation. We do not include a sixth cause that deals with cost savings to overcome decreasing competitive pressure because cost savings are stressed under "economic efficiency".

[6] For most mergers, the major cost saving potential is in labor costs. Using a sample of five mergers, EIA (1999) concluded that over 50% of the expected saving came from a reduction in corporate and operations labor. See FERC (1981) for a detailed description of 15 sources of cost savings for generation and transmission by power pooling.

[7] See EIA (1999), p. 33, for a description of the strategic benefits of a combined electric and natural gas company over all natural gas supply-chain segments. For electricity distributors, the benefits emerge by cross-selling activities, expanding overhead over a larger customer base and combining administrative functions.

antitrust policy has focused largely on *preventing* the formation of uncompetitive market structures (ex-ante) and *prosecuting* explicit collusion ex-post (Bushnell 2003, p. 4).

FERC's antitrust and regulatory authority over IOUs derives from the Federal Power Act of 1935 (FPA). The commission has jurisdictional power over wholesale electricity transactions and their supporting transmission arrangements (Bushnell 2003, pp. 4-5). In 1992, Congress enacted the Energy Policy Act giving FERC the authority to approve third-party access (TPA) to the national transmission grid to support the newly developing competitive wholesale market. FERC adopted the horizontal merger guidelines of the Department of Justice (DOJ) and the Federal Trade Commission (FTC) in 1996, drawing upon their experience and to minimize potential differences among the federal agencies that share jurisdiction over proposed M&A (Pierce 2005, pp.7-11).[8]

Typically, a merger review process includes: identification of the relevant products and the relevant geographic markets and an estimation of the price effect of the proposed merger as measured by its impact on supplier concentration in the relevant market. For electricity M&A, the products are non-firm energy, short-term capacity (firm energy), and long-term capacity, i.e. the most frequently traded products among the non-restructured vertically integrated utilities on the periphery of the spot market (Bushnell 2003, p. 6).[9]

3 METHODOLOGY

Next, we describe our measurement of cost efficiency and total factor productivity (TFP) using SFA on panel data and our assessment of the impacts of merger characteristics on efficiency scores.

3.1 Cost function specification

As mentioned above, we wish to combine the advantages of the methods applied in previous research. We use the parametric, SFA in a cost function framework to allow for random unobserved heterogeneity among the different distributors, but note that it lacks a specification of a functional

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[8] FERC is frequently involved in reviewing M&As to ensure competitive markets and access to reliable service at reasonable prices. In recent years, DOJ has relied upon FERC's analyses and assumed a more passive role.

form. The cost efficiency is the product of technical efficiency (TE) and allocative efficiency (AE); the first term describes the efficiency in the use of production technology; the second term displays the efficiency in production factor allocation.[10]

The original stochastic frontier model by Aigner, Lovell and Schmidt (1977) and Meeusen and van den Broeck (1977) shows:

$$Y_i = X_i{}' \beta + v_i - u_i \tag{1}$$

where Y_i represents the logarithm of the output vector of company i, X_i is a vector that contains the logarithms of inputs, β is a vector of parameters to be estimated, v_i is a random error term accounting for statistical noise and assumed to have a normal distribution, and u_i is a non-negative random variable associated with technical inefficiency (often assumed to be half-normal or truncated-normal distribution). The maximum likelihood estimated method is used here to calculate the technical inefficiency parameter u_i for a one-output case.

This paper applies an alternative frontier cost model to a panel dataset. Pitt and Lee (1981) extended the original SFA approach, shown in (1), to a panel data framework, which can be formulated as follows:[11]

$$\ln C_{it} = \ln C(Y_{it}, W_{it}) + v_{it} + u_i \tag{2}$$

with C_{it} displaying the observed total costs of firm i in year t, the cost function C, the vector of outputs Y_{it} and the input price vector W_{it}. The underlying assumption is that the cost function defines minimum costs at a given output level, input prices, and the existing production technology with the corresponding properties of linear homogeneity and concavity in input prices and monotonicity in input prices and output.[12]

We consider that the distribution utilities are operating in a given network with the objective to deliver electricity to an exogenously defined area. Therefore, they transform capital and labor into outputs:

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[9] See Pierce (2005) for an overview of the development of FERC's work and policies; see Bushnell (2003) for a full description of the US merger review process.

[10] See Coelli at al. (2005) and Kumbhakar and Lovell (2000) for a detailed discussion of the components of cost efficiency.

[11] A useful discussion about the alternative frontier cost models is in Farsi and Filippini (2004).

[12] See Coelli et al. (2005), pp. 21-30, and Kumbhakar and Lovell (2000), pp. 32-35, for more details concerning the properties of a cost function.

our paper's outputs are the amount of electricity delivered and the total number of connected customers. The heterogeneity of different service areas is often defined by additional network characteristics. We control for this by using a network density parameter ND_{it} that is the logarithm of customers per unit of distribution assets, and expect a distributor to have lower costs when it acts in a densely populated area that is indicated by a higher value of the variable. In addition, we use a time trend t to assess the technological change for the entire electricity industry.

A transcendental logarithmic (translog) function is generally chosen for estimating the cost function given in (2) because its flexible form places no restrictions on the elasticity of substitution at the outset and it allows economies of scale to differ with the level of output. Two alternative approaches can also be used. The first considers the translog function as a local second-order logarithmic approximation to any arbitrary twice-differentiable cost function. The sample mean is often used as an approximation point (mean correction).[13] Moving away from this point, any implicit approximation errors will grow. The second approach considers the function as an exact representation of the minimum cost function, in which case there is no need to define an approximation point (Berechmann 1993, p. 138). For this paper, we employ the first approach, correcting the sample variables by their means due to the advantages of reduced effects of outliers, and without affecting the data structure and the convenient interpretation of first order coefficients as elasticities at sample means (Coelli et al. 2003). The total cost function can be written as:

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[13] For an example, see Farsi, Filippini and Kuenzle (2006) and Growitsch, Jamasb and Pollitt (2005).

$$
\begin{aligned}
\ln\left(\frac{C_{it}}{W_{L\,it}}\right) = {} & \beta_0 + \beta_{Y_E}\ln Y_{E\,it} + \beta_{Y_{NC}}\ln Y_{NC\,it} + \beta_{W_K}\ln\frac{W_{K_{it}}}{W_{L_{it}}} \\
& + \frac{1}{2}\beta_{Y_E Y_E}\left(\ln Y_{E\,it}\right)^2 + \frac{1}{2}\beta_{Y_{NC}Y_{NC}}\left(\ln Y_{NC\,it}\right)^2 + \frac{1}{2}\beta_{W_K W_K}\left(\ln\frac{W_{K_{it}}}{W_{L_{it}}}\right)^2 \\
& + \beta_{Y_E Y_{NC}}\ln Y_{E\,it}\ln Y_{NC\,it} + \beta_{Y_E W_K}\ln Y_{E\,it}\ln\frac{W_{K_{it}}}{W_{L_{it}}} + \beta_{Y_{NC}W_K}\ln Y_{NC\,it}\ln\frac{W_{K_{it}}}{W_{L_{it}}} \\
& + \beta_{ND}\ln ND_{it} + \beta_{NDND}\left(\ln ND_{it}\right)^2 + \beta_{Y_E ND}\ln Y_{E\,it}\ln ND_{it} \\
& + \beta_{Y_{NC}ND}\ln Y_{NC\,it}\ln ND_{it} + \beta_{W_K ND}\ln\frac{W_{K_{it}}}{W_{L_{it}}}\ln ND_{it} + \beta_t t + u_{it} + v_{it}
\end{aligned}
\tag{3}
$$

where the output variables Y_E and Y_{NC} represent the quantity of electricity delivered and the number of customers respectively, W_C and W_L are the input price variables of capital and labor respectively, t displays the time trend, ND_{it} is the network density and β are the coefficients to be estimated. The linear homogeneity condition is imposed by normalizing the costs and the capital price by the labor price W_L.

Thus, we can calculate the economies of scale (*ES*) as the inverse sum of the cost elasticities of output *i* (Berechmann 1993, p. 118):

$$
ES = \frac{1}{\sum_i CE_i} = \frac{1}{\sum_i \partial\ln C_{it} \big/ \partial\ln Y_{it}} \tag{4}
$$

If ES > 1, it implies economies of scale because a doubling of output increases the costs by less than 100 percent. Respectively, there are diseconomies of scale if ES < 1.

3.2 Explaining efficiency

We are also interested in explaining the efficiency. Earlier authors have utilized a two-stage approach: in the first stage, the inefficiencies are calculated by a frontier model omitting environmental – or structural – variables, and in a second stage, the estimated inefficiencies are regressed on those exogenous environmental variables to assess their impact on efficiency).

This two-stage approach has been criticized because of econometrical inconsistences in the assumptions made about the distribution of the inefficiencies (see Kumbhakar, Ghosh and McGukin (1991) and Reifschneider and Stevenson (1991)). In the first stage, the inefficiency effects are assumed to be distributed independently and identically, but in the second stage, the predicted inefficiencies are assumed to be a function of firm-specific effects, which implies that they are not distributed identically. As a solution these authors have proposed stochastic frontier models in which the inefficiency effects (u_i) are expressed as an explicit function of a vector of company-specific variables and a random error. The model proposed by Battese and Coelli (1995) is similar to the specification of Kumbhakar, Ghosh and McGukin (1991) but the latter authors impose allocative efficiency, delete the first-order conditions on profit maximization and extend it to panel data. Their model assumes the inefficiency term u_{it} to be distributed independently as truncations at zero of the $N(\mu_{it},\sigma_U^2)$ with

$$\mu_{it} = \delta' z_{it} \tag{5}$$

where z_{it} is a vector of environmental variables and δ is a vector of coefficient to be estimated (Coelli, Rao and Battese 1998, pp. 207-209; Coelli, 1996).

We use specific factors that are likely to influence the production environment to account for a firm's M&A. One of our two model pairs adopts the idea of measuring the merger's the time path as proposed by Kwoka and Pollitt (2005). We introduce separate 'merger timing' dummies for each year before and after a merger, and for 'buyers' and 'target' respectively. We also capture separately the effect of involvement in two or three mergers as a 'buyer' or a 'target'. This second model pair does not account for the time path of a merger and uses only dummies describing a firm's status: 'have acquired' and 'have been acquired' post-merger, and 'will acquire' and 'will be acquired' pre-merger. We treat the involvement by one company in more than one merger as described above. All dummies can take on a value of 0 or 1 for each year and firm. There is only one model of each model pair that accounts for the customer density in the cost function.

In addition to the merger dummies, we include a time trend t to capture the effect of systematic industry-wide efficiency improvements that result from learning over time (experience) and a constant.[14] We can now describe the mean of the inefficiency term as:

$$\mu_{it} = \delta_0 + \delta_t t + \sum_m \delta_m d_{m\,it} \tag{6}$$

where d_{it} displays all of the dummies.

For the purpose of calculation, we use the software "FRONTIER 4.1" developed by Coelli (1996).

4 DATA

We follow Kwoka and Pollott (2005) in the definition of data and the calculation of variables for the electricity distributors, thus requiring: total expenditures (TOTEX); operating and maintenance expenditures (O&M); output quantities; input quantities; input prices; and structural variables.

We use distributors' FERC Form 1 filings for 1994-2001 and merger data dated by the year FERC issued a decision.[15] The original dataset consists of 295 IOUs and reduced to 109 IOUs due to the lack of data concerning some variables[16], where the subsample used accounts for 70 percent of total electricity sold and 54 percent of total customers in 2000. The ratios are quite constant for all years in our sample period. Thus, our balanced panel comprises 872 observations.[17]

We then classify the 109 IOUs into buying utilities (25), acquired companies (21), and non-merging utilities (67). The difference of 4 results from firms that are buying as well as acquired utilities. Table 1 displays the distribution of the mergers during our time period.

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[14] The introduction of a time trend is the easiest way to account for the systematic change of inefficiency over time. See Kumbhakar and Lovell (2000) for a comparison of the more complex and common time-varying functions of Battese and Coelli (1992) and Kumbhakar (1990).

[15] In some cases there is a one-year lag between the issuance of the final decision by FERC and the completion of the merger. Additional reviews by state agencies can sometimes delay a pending merger.

[16] To some extent, the lack of data is explained by M&A itself. For example, the number of filings drops from two to one when two regulated firms merge and form a new entity afterward.

[17] For three of the missing 872 observations, we calculated an average of the O&M and the total employees using the preceding and the following year.

[Insert Table 1 here]

The variables used and the corresponding sources and modification are displayed in Appendix 2. Unlike Kwoka and Pollitt (2005), we calculate the Total Distribution Assets (TDA) as the sum of the distribution assets (DA) and the share of total distribution assets of all assets (S2) times other assets (OA):

$$TDA = DA+S2*OA$$

We also calculate the total Number of Units Delivered (Nud), and a capital price variable (Average Capital Price - AvCP) that is the ratio of capital costs (CC) and Total Distribution Assets:

$$AvCP = CC / TDA = EBITDA / TOT$$

AvCP is the ratio of EBITDA and total assets that assumes a constant capital price for the entire supply chain. The number of employees in distribution (TDemp) is calculated as a product of total employees (Temp) times the share of distribution on total salaries (S1).

Deflation of costs and factor prices is unnecessary because these variables are already divided by a factor price to achieve homogeneity of the cost function. The summary statistics of the variables used are shown in Table 2.

[Insert Table 2 here]

5 ESTIMATION RESULTS

The estimation results of the two models are provided in Table 3. Almost all models show significant positive coefficients of the outputs and the input prices of the cost function.

[Insert Table 3 here]

Since total costs and all explanatory variables are in logarithms and normalized by their means, the cost elasticities of energy delivered are quite low on average with 0.13 to 0.15. Model 1 shows an curious, slightly negative value; an increase of 1 percent in customer numbers will increase the costs by 0.81-0.96 percent depending on the specification chosen. As expected, the impact of network density is significantly negative and equal for both models with a value of -0.68 percent. This indicates that a distributor operating in an urban area with a high density has a cost advantage compared to a rural company.[18] Due to the homogeneity, the cost elasticities with respect to input prices are equal to their cost shares. Interestingly, we observe a high cost share of capital, ranging from 72 to 80 percent despite the fact that our dataset shows a cost share of only 58 percent on average. However, the results support the structure of a high capital/labor ratio that is typical for network industries with high capital investments. The coefficient of the time trend is negative and significant in the two models, which indicates a positive technological change of 1 percent over time and that distribution technology has not changed much over time.

Concerning the environmental variables in the inefficiency equation, the results of the estimation of the coefficients show a significantly positive time trend on inefficiency change over all specifications. This indicates a negative learning effect of 6-8 percent per year in terms of efficiency. The coefficients of the merger dummies are significant only in some portions, but their magnitude reveals the notable differences among buyer, target firms and non-merging firms.

The positive coefficients of the time path dummies in Models 1 and 1a indicate the higher inefficiencies of the buyers pre-merger, and large efficiency gains post-merger. In other words, the cost efficiency of bad-performing buyers improves remarkably in comparison with the non-merging control group. On the other hand, we can say little about the acquired firms in the pre-merging period. The insignificance of all related coefficients can be interpreted as the cost performance that is similar to the control group. Since the first merger, the target firms have higher cost inefficiencies than the control group. The estimation also shows interesting results about the target firms involved in more

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[18] We note that the incorporation of the network density variable aligns with the systematically higher cost elasticities of the customer numbers. This suggests a potential problem of multicollinearity because the customer number is also used in calculating the network density variable.

than one merger. All of our models indicate they are good cost performers (cost inefficiency below that of the control group) except for a target firms which was acquired three times.

Recalling the argument of Farrell and Shapiro (1990) that economies of scale (ES) are a driving force for welfare-enhancing mergers, we investigate the scale effects of the merging parties. As seen in Table 4, we find ES on average of 1.04 to 1.06, depending on the model. Interestingly, the merging parties almost always face slightly higher scale effects than the non-merging distributors and they always increase their scale effects by merging, but the buyer to a notably higher extent. Models 1a and 2a do not show remarkable differences between buyer and targets.[19] The notable cost efficiency shift (Table 3) appears to be mainly driven either by technical and/or allocative efficiency.[20]

[Insert Table 4 here]

[Insert Table 5 here]

Concerning the overall evaluation of the models, the γ coefficients (measuring the share of the deviations from the cost function due to inefficiency) are about 90%. The decision to include a network density variable can be evaluated by a likelihood-ratio test that proofs the network density variables to be zero at a given significance level. The results are shown in Table 5. For both models we can reject the null hypothesis at a 99 percent level in favor of Models 1 and 2 with network density variables included.[21]

Table 6 gives a summary of the inefficiency estimates. The inefficiency measures can be interpreted as excess costs measured by the ratio of actual costs to efficient cost. The value can be equal or greater than one where a value of one indicates cost-efficient firms. The inefficiency values show similarity within the pairs of models which contain (omit) network density variables in the cost function Models 1 and 2 (Models 1a and 2a). There are remarkable differences between the pairs in the inefficiency

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[19] We do not consider Model 1 and Model 2 since they are subject to curious or non-significant cost elasticities.

[20] We also calculated DEA and Tobit regressions on the data sample and reveal that changes in technical efficiency cause the non-synchronous efficiency effects of mergers while post-merger changes in allocative efficiency favor targets rather than buyers.

values, where we observe higher inefficiency in the models omitting the network density variables. This is reasonable because in the first model pair, we control for network density, which displays the cost disadvantage of firms that operate in a less densely populated area resulting in a mean disadvantage of 10 to 15 percent inefficiency. The mean inefficiency shows excess costs of 13 to 33 percent depending on the specification chosen. The quite small positive difference between mean and median, as well as the low 95 percentile value suggest that there are only a few very inefficient firms with a maximum value across all models of 330 percent.

[Insert Table 6 here]

[Insert Table 7 here]

The pair-wise correlation coefficients between the inefficiency estimates from our different models are listed in Table 7. The basic result is the high correlation of over 97 percent of the inefficiency estimates between Models 1 and 2 and Models 1a and Model 2a respectively. Across all models, the correlation is at least 60 percent.

6 CONCLUSION

In this paper we have analyzed the effects of mergers on the efficiency of the merging utilities. We applied parametric SFA on a panel dataset of 109 IOUs from the US for the years 1994-2001. Cost efficiency and merger effects on efficiency are estimated simultaneously in a one-stage procedure following Battese and Coelli (1995).

The estimation results of the cost function show relatively low cost elasticities with respect to the electricity delivered. The cost elasticities of the output ‘number of customers’ lie in the range of 80-100 percent, correlating with the existant literature. The results indicate that mergers change the

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[21] In addition, we tested the assumption of a Cobb Douglas cost function and the specification of a density variable that enter the equation only with a first order derivation. Both assumptions could be rejected for both models applying a likelihood-

efficiencies of the merging parties significantly. The buying firms were bad cost performers in the pre-merger period (more inefficient compared to the control group of non-merging utilities) and, post-merger, gained efficiency, thus becoming good cost performers. In contrast, the target firms were average cost performers (as inefficient as non-merging firms) pre-merger, and, post-merger, lost efficiency, thus becoming bad performers. Hence, the overall effect of the merged firm remains ambiguous. We cannot confirm the cost savings of a merger, nor their magnitude, but we can state that economies of scale appear to be relevant in explaining the efficiency increase of the buyers but irrelevant for the target firms.

Post-merger improvements suggest that the new companies shift technology and processes from target firms to buyers. The parametric approach we applied does not allow investigating the channels by which efficiencies can be transferred from one company to another, and in particular why target firms' efficiency decreases. In addition to the implementation of more structural parameters to improve the cost function, such as transformer capacity, line length and quality, future research might include: decomposing cost inefficiency into technical and allocative components to reveal the sources of the inefficiency; and examining the rise in convergence mergers (combining electricity and natural gas) to analyze economies of scope.

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ration test on a 99 percent level.

APPENDIX

Appendix 1: Mergers in the Electricity Sector Approved by FERC 1995-2001

Merger status	Buyer	Target/Acquired/Merged	In Panel
Completed in 2001	E.ON AG	Powergen plc	
	Potomac Electric Power Company	Conectiv	
	Energy East Corp.	RGS Energy Group	
	National Grid USA	Niagara Mohawk Holdings, Inc.	X
	The AES Corporation	IPALCO Enterprises, Inc.	
	FirstEnergy Corporation	GPU, Inc.	X
	Emera	Bangor-Hydro Electric Company	
Completed in 2000	Entergy Power Marketing Corp.	Koch Energy Trading, Inc.	
	UtiliCorp United, Inc.	St. Joseph Light & Power Company	X
	Carolina Power & Light (CP&L) Energy, Inc.	Florida Progress Corporation	X
	Interstate Power Company	IES Utilities, Inc.	
	PowerGen plc	LG&E Energy Corporation	X
	Black Hills Corporation	Indeck Capital, Inc.	
	Stora Enso Oyj (F/S)	Consolidated Water Power Company	
	Consolidated Edison, Inc.	Northeast Utilities	
	PECO Energy Co.	Commonwealth Edison Co.	X
	Energy East Corp.	CMP Group, Inc.	
	American Electric Power Company	Central and Southwest	X
	Northern States Power Co. (Minnesota)	New Century Energies, Inc.	X
Completed in 1999	Pennsylvania Enterprises	Southern Union Co.	
	New England Electric System	Eastern Utilities Associates	X
	BEC Energy	Commonwealth Energy System	X
	ScottishPower plc	PacifiCorp	
	National Grid Group plc	New England Electric System	X
	The AES Corporation	CILCORP Inc.	X
	Sierra Pacific Power Company	Nevada Power Company	X
	Consolidated Edison Company of New York, Inc.	Orange and Rockland Utilities, Inc.	X
Completed in 1998	CalEnergy Company, Inc.	MidAmerican Energy Holdings Company	
	Duke Energy Corporation	Nantahala Power and Light Company	X
	WPS Resources Corporation	Upper Peninsula Energy Corporation	X
	Wisconsin Energy Corporation, Inc.	Edison Sault Electric Company	X
	Louisville Gas and Electric Company	Kentucky Utilities Company	X
Completed in 1997	Wisconsin Power & Light Company	IES Utilities, Inc. Interstate Power Company	X
	Ohio Edison Company	Centerior	X
	Union Electric Company	Central Illinois Public Service Company	X
	Delmarva Power & Light Company	Atlantic City Electric Com	X
	Destec Energy, Inc.	NGC Corporation	
	Enova Energy, Inc.	San Diego Gas & Electric Company	X
	Public Service Company of Colorado	Southwestern Public Service Company	
Completed in 1995	Delmarva Power & Light Company	Conowingo	X

Source: DOE, 1999. *Changing structure of the electric power industry 1999: Mergers and Other Corporate Combinations*, http://www.eia.doe.gov/cneaf/electricity/corp_str/corpcomb.pdf and FERC's website.

Appendix 2: Variable Definition and Sources

Variable	Definition	FERC Pages	FERC Account Name/Notes
OPEX		**Electric Operation & Maintenance Expenses**	**FERC database table f1_elc_op_mnt_exp**
D	Total Distribution Costs (US$)	322-126b	TOTAL Distribution Expenses
A	Total Administration Costs (US$)	322-168b	TOTAL Administration 6 General Expenses
Cu	Total Customer Service Costs (US$)	Sum of 322-134b, 322-141b, 322-148b	
		322-134b	TOTAL Customer Accounts Expenses
		322-141b	TOTAL Customer, Service and Information Expenses
		322-148b	TOTAL Sales Expenses
T	Total Transmission Costs (US$)	321-100b	TOTAL Transmission Expenses
G+PP	Total Power Production Costs (US$)	321-80b	TOTAL Production Expenses
Wage distribution		**Distribution of Salaries & Wages**	**F1_slry_wg_dstrbtn**
S1	Share of Distribution Business in Administration	S1(a) / S1(b)	
S1(a)	Numerator (wages of distribution and customer)	Sum of 354-20b, 354-21b, 354-22b, 354-23b	
		354-20b	Distribution
		354-21b	Customer Account
		354-22b	Customer Services and Informational
		354-23b	Sales
S1(b)	Denominator (wages)	354-25b	TOTAL Operations and Maintenance
Assets		**Electric Plant in Service**	**F1_plant_in_srvce**
S2	Total Distribution Share of EBITDA	TDA / TOT = DA / (TOT-OA)	
DA	Distribution Assets (US$)	207-69g	TOTAL Distribution Plant
TA	Transmission Assets (US$)	207-53g	TOTAL Transmission Plant
PA	Production Assets (US$)	207-42g	TOTAL Production Plant
TOT	Total Assets (US$)	207-88g	TOTAL Plant in Service
OA	Other Assets (US$)	TOT - (DA+TA+PA)	
TDA	Total Distribution Assets	DA + OA*S2	
Revenues		**Electric Operation Revenues**	**F1_electrc_oper_rev**
R	Total Revenue (US$)	300-12b	TOTAL Sales of Electricity
Nud	Total Units Delivered (MWh)	301-12d	TOTAL Unit Sales (MWh)
Ncu	Total Customers (#)	301-12f	TOTAL Sales to Consumers (#)
Others			
EBITDA		R-D-Cu-T-(G+PP)-A	Earning before Interest, Taxes, Depreciation, Amortization
CC	Capital Costs in Distribution Business	S2*EBITDA	
NCC	Non-Capital Costs	D+Cu+S1*A	O&M of Distribution
TDC	Total Distribution Costs	CC+NCC	
Temp	Total Employees	323-4	TOTAL Employees (#)
TDemp	Total Employees in Distribution	S1*Temp	
AvW	Average Wages in Distribution	(354-25b) / Temp	
LEQ	Labor Equivalent O&M Costs	NCC / AvW	O&M Costs deflated by Labor Costs
AvCP	Average Price of Capital	CC / (DA+S2*OA) = EBITDA / TOT	

Table 1: Number of Electricity Mergers in the Sample

Year	Buyer	Target
1994	0	0
1995	1	0
1996	0	0
1997	4	6
1998	4	2
1999	5	5
2000	8	8
2001	4	1
SUM	**26**	**22**

Table 2: Summary Statistics

Variable	Explanation	Obs	Mean	Std. Dev.	Min	Max
C	Total Distribution Costs	872	283,000.000	350,000,000	2,299,131	2,660,000,000
Y_E	Total Electricity Sold (MWh)	872	21,000,000	23,600,000	128,208	182,000,000
Y_{NC}	Total Number of Customers (#)	872	606,348	702,499	5,565	3,935,296
X_L	Total Employees in Distribution (#)	872	860	945	3	5.096
X_K	Total Distribution Assets ($)	872	1,250,000,000	1,590,000,000	8,390,768	16,500,000,000
W_L	Avg. Costs of Labor	872	47,691	109,182	15,197	1,892,592
W_K	Avg. Price of Capital	872	0.132	0.040	0.029	0.425

Table 3: Maximum Likelihood Estimation Results of the Models

Coefficient	Model 1	Model 1a (without ND)	Coefficient	Model 2	Model 2a (without ND)
β			β		
constant β_0	0.02 (1.25)	-0.12*** (-4.62)	constant β_0	0.01 (0.93)	-0.14*** (-5.41)
t	-0.01*** (-4.18)	0.00 (-0.58)	t	-0.01*** (-3.75)	-0.01 (-1.47)
Y_E	-0.03* (-1.80)	0.13*** (6.15)	Y_E	-0.02 (-1.25)	0.15*** (7.36)
Y_{NC}	0.97*** (62.21)	0.83*** (37.21)	Y_{NC}	0.96*** (61.37)	0.81*** (36.75)
W_K	0.79*** (43.67)	0.72*** (31.12)	W_K	0.80*** (48.71)	0.72*** (31.49)
Y_EY_E	0.09*** (3.18)	-0.46*** (18.64)	Y_EY_E	0.09*** (2.94)	-0.44*** (-18.88)
$Y_{NC}Y_{NC}$	0.12*** (3.30)	-0.58*** (19.88)	$Y_{NC}Y_{NC}$	0.11*** (2.96)	-0.56*** (-20.11)
W_KW_K	-0.20*** (-11.83)	-0.19*** (-7.91)	W_KW_K	-0.20*** (-11.79)	-0.19*** (-8.12)
Y_EY_{NC}	-0.11*** (-3.65)	0.51*** (22.05)	Y_EY_{NC}	-0.11*** (-3.32)	0.49*** (22.53)
Y_EW_K	-0.03 (-1.15)	-0.23*** (-5.35)	Y_EW_K	-0.03 (-1.18)	-0.20*** (-4.88)
$Y_{NC}W_K$	0.06** (1.99)	0.27*** (5.83)	$Y_{NC}W_K$	0.06** (1.99)	0.25*** (5.42)
ND	-0.68*** (-27.90)		ND	-0.68*** (-27.32)	
NDND	-0.26*** (-4.46)		NDND	-0.22*** (-3.81)	
Y_END	-0.02 (-0.65)		Y_END	0.00 (-0.09)	
Y_{NC}ND	-0.03 (-0.91)		Y_{NC}ND	-0.05 (-1.58)	
W_KND	0.06 (1.12)		W_KND	0.03 (0.68)	

continued

Coefficient	**Model 1**	**Model 1a (without ND)**	**Coefficient**	**Model 2**	**Model 2a (without ND)**
δ			***δ***		
constant δ_0	-0.69***	-0.51**	constant δ_0	-0.71***	-0.19**
	(3.43)	(-2.42)		(-3.91)	(-2.04)
t	0.06***	0.08***	*t*	0.05***	0.06***
	(3.34)	(4.74)		(3.66)	(4.49)
More than once a buyer	-0.88	-0.87			
	(-1.09)	(-1.06)			
More than once a target	-1.63**	-3.08*			
	(-2.02)	(-1.69)			
Buyer: 7 years before	0.46	0.80***	Buyer: before first merger	0.00	0.08*
	(1.14)	(3.02)		(-0.05)	(1.66)
Buyer: 6 years before	0.32*	0.23	Buyer: before second merger	0.52***	-0.48*
	(1.74)	(1.35)		(3.00)	(-1.82)
Buyer: 5 years before	0.34**	0.46***	Buyer: since first merger	-0.51***	-0.03
	(2.21)	(3.31)		(-5.13)	(-0.63)
Buyer: 4 years before	0.32**	0.31***	Buyer: since second merger	0.29	-0.18
	(2.43)	(2.57)		(1.01)	(-0.87)
Buyer: 3 years before	-0.26	-0.03			
	(-1.06)	(-0.24)			
Buyer: 2 years before	-0.15	-0.02			
	(-0.98)	(-0.16)			
Buyer: 1 years before	-0.29	-0.11			
	(-1.28)	(-1.04)			
Buyer: 1 year after	-0.80***	0.03			
	(-2.63)	(0.36)			
Buyer: 2 year after	-0.58	-0.12			
	(-1.53)	(-0.69)			
Buyer: 3 years after	-0.99*	-0.93**			
	(-1.70)	(-2.17)			
Buyer: 4 years after	-0.61	-0.94**			
	(-0.79	(-1.96)			
Buyer: 5 years after	0.12	0.41			
	(0.12)	(0.40)			
Buyer: 6 years after	1.23	0.97			
	(1.30)	(1.04)			
Target: 7 years before	0.51	0.13	Target: before first merger	0.03	0.03
	(1.15)	(0.19)		(0.46)	(0.52)
Target: 6 years before	-0.36	-1.09	Target: before second merger	-1.43***	-2.27**
	(-0.53)	(-1.67)		(-12.77)	(-2.42)
Target: 5 years before	-1.09	0.00	Target: before third merger	1.44***	1.20
	(-1.38)	(0.02)		(6.65)	(1.57)
Target: 4 years before	-0.29	-0.15	Target: since first merger	0.29***	0.15***
	(-0.68)	(-0.66)		(4.57)	(3.04)
Target: 3 years before	0.08	-0.12	Target: since second merger	-1.86***	-2.05**
	(0.55)	(-0.88)		(-3.00)	(-2.27)
Target: 2 years before	-0.13	-0.20	Target: since third merger	-0.07	0.73
	(-0.70)	(-1.30)		(-0.07)	(0.67)
Target: 1 year before	0.13	0.03			
	(1.15)	(0.29)			
Target: 1 year after	0.09	-0.01			
	(0.67)	(-0.07)			
Target: 2 year after	0.27**	0.21**			
	(2.43)	(2.07)			
Target: 3 year after	0.07	0.21			
	(0.32)	(1.47)			
Target: 4 year after	0.35*	0.24			
	(1.91)	(1.52)			
σ^2	0.08***	0.13***	σ^2	0.09***	0.09***
	(5.45)	(5.02)		(6.06)	(9.88)
$\gamma = \sigma^2_u/\sigma^2$	0.91***	0.88***	$\gamma = \sigma^2_u/\sigma^2$	0.92***	0.88***
	(46.15)	(36.64)		(59.46)	(40.94)
Log Likelihood	539.54	126.22	Log Likelihood	537.09	132.27

Significance on 10%-, 5%-, and 1%-level: *, **, ***; t-statistics in parentheses.

Table 4: Economies of Scale

Group	Period	Model 1	Model 1a (without ND)	Model 2	Model 2a (without ND)
Buyer	Pre-merger	1.062	1.026	1.071	1.030
	Post-merger	1.087	1.040	1.087	1.045
Target	Pre-merger	1.062	1.039	1.066	1.043
	Post-merger	1.066	1.042	1.066	1.046
Sample average	8 years	1.062	1.036	1.062	1.040

Table 5: Likelihood-Ratio Test of the Models

Null hypothesis	Degrees of freedom	$\chi^2_{0.99}$	Test statistics	Decision
Model1: do not include ND $\beta_{ND} = \beta_{NDND} = \beta_{Y_E ND} = \beta_{Y_{NC} ND} = \beta_{NDW_K} = 0$	5	15.09	826.64	Reject H_o
Model2: do not include ND $\beta_{ND} = \beta_{NDND} = \beta_{Y_E ND} = \beta_{Y_{NC} ND} = \beta_{NDW_K} = 0$	5	15.09	809.64	Reject H_o

Table 6: Summary of Inefficiency Measures

	Model 1	Model 1a (without ND)	Model 2	Model 2a (without ND)
Mean	1.134	1.286	1.137	1.331
Median	1.091	1.200	1.093	1.249
Minimum	1.011	1.023	1.011	1.020
Maximum	2.655	3.147	2.715	3.303
95th Percentile	1.368	1.784	1.368	1.860

Table 7: Pair-wise Pearson Correlation between Inefficiency Estimates

	Model 1	Model 1a (without ND)	Model 2	Model 2a (without ND)
Model 1	1.000			
Model 1a (without ND)	0.631	1.000		
Model 2	0.977	0.623	1.000	
Model 2a (without ND)	0.604	0.995	0.615	1.000

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