THE EFFICIENCY EFFECTS OF ELECTRIC UTILITY MERGERS: LESSONS FROM STATISTICAL COST ANALYSIS

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I. Introduction and Overview

Merger mania would be too strong a characterization of events in the electric utility industry during the decade of the 1980s. Certainly, utility mergers were proposed and implemented more frequently than in previous decades; indeed, several hostile takeovers were attempted in 1990. However, the pace of mergers during this decade was still fairly measured and sedate. Since enactment of the Energy Policy Act of 1992 (EPAct),[1] however, the pace of activity has been anything but measured. Maniacal may be the more appropriate characterization.

In response to the increased merger activity overall, state and federal regulatory authorities increasingly have been required to assess the impacts of the mergers on the public interest. Irrespective of the legal standard applied,[2] regulators have therefore sought to elicit evidence from the merging parties concerning the operational and capital efficiencies predicted to be induced by the merger. They have also sought to ascertain whether the predicted efficiencies would be passed on to the rate payers in a nondiscriminatory fashion.

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1. Pub. L. No. 102-486, 106 Stat. 2782 (codified at 42 U.S.C. §§ 13,201-13,556 (1994)).

2. I do not address the question of the appropriate legal standard here. The United States Federal Energy Regulatory Commission (FERC) fairly consistently has used the "consistent with the public interest" standard. *See, e.g.*, *Kansas City Power & Light Co.*, 53 F.E.R.C., ¶ 61,077 (1990); *Utah Power & Light Co.*, 41 F.E.R.C., ¶ 62,283, 61,752 (1987). The FERC has recently reiterated this standard with the Entergy merger, stating that the FERC "may weigh and balance HHI calculations with a number of factors to determine whether a proposed merger is consistent with the public interest." *Entergy*, 64 F.E.R.C., ¶ 61,001, 61,011 (1993). The other factors weighed in the determination often include the efficiencies induced by the merger, entry conditions, the potential for lessening competition through coordinated interactions and the financial strength of the merging firms—not surprisingly, factors examined by the Department of Justice (DOJ) and Federal Trade Commission (FTC) in deciding whether to challenge non-utility mergers.

State PUCs may have different legal standards, including, but not limited to, "positive net benefits," "no detriment" or "not contrary to the public interest." However, whatever the standard, these regulators still must examine estimates of the efficiencies induced by the proposed merger. Hence, within all jurisdictions, regulators base their decisions to some extent upon *ex ante* estimates of merger-induced efficiencies.

In the process, massive quantities of sometimes conflicting technical evidence have been produced. Merger proponents invariably predict substantial efficiency gains, making use of a variety of production cost models. Just as frequently, merger opponents claim to demonstrate that a proposed merger will not produce efficiency gains. The proper implications to be drawn from the conflicting technical detail are frequently difficult to discern.

In this paper, I develop information that can assist regulators and the courts in assessing the accuracy of the efficiency gains predicted by merger applicants. I argue that the *ex ante* efficiency predictions of applicants are frequently inaccurate and unreliable. I contend, therefore, that statistical cost analysis is necessary to assess their credibility. In the process, I review and summarize a variety of statistical cost analyses and draw conclusions relevant to utility merger policy.

The paper proceeds as follows: In Section II, I provide a historical context which identifies the technological and economic sources of efficiency gains in electric utility operations. If predicted efficiency gains are to be effectuated through merger, the merger must explicitly exploit these technological and economic realities. The historical context indicates that scale economies in power generation at the unit and plant levels were the most important determinant of utility economics and efficiency gains during the first half of this century. However, fundamental technological and economic changes have occurred since 1965, making equally important the transmission and distribution of electricity to spatially-dispersed customers. These changes have increased the importance of the vertical coordination of generation, transmission and distribution.

Having explored the technological sources of efficiencies, I introduce the most significant utility mergers of the past twenty years. I identify the efficiency gains predicted for these mergers and selectively discuss the credibility of the predictions by examining whether the mergers could have exploited the vertical efficiencies identified in the historical review. I critique their credibility in light of the fact that they are *ex ante* predictions and may therefore be distorted for strategic reasons.

I conclude Section II by discussing the relevance of these historical technological trends to recent proposals for restructuring the electric power industry.

Taking the potential and observed inaccuracies of *ex ante* efficiency studies as a point of departure, Section III describes a cost-based methodology for better identifying and analyzing efficiency gains achievable through utility merger. This method is statistical cost analysis. The discussion indicates how the efficiencies can be quantified. The Section implements the cost methodology by summarizing a variety of statistical cost analyses and indicates their relevance to merger policy. Section IV summarizes the paper.

II. The Gains from Utility Mergers: Historical Perspective, Implications for Predictions of Merger-Induced Efficiencies and Relevance to Recent Restructuring Proposals

A. *Historical Perspective*

The original economic and technological focus of the electric utility industry was power generation. In its early stages, the industry consisted of small isolated plants that generated power for localized areas. Transmission technology was relatively undeveloped. Service territories were consequently limited in size by the short distances over which electricity could be transmitted and distributed. Within these small service territories, generation, transmission and distribution of electricity truly constituted a natural monopoly. Early regulatory and statutory treatment of the industry reflected these realities.[3]

Early technological developments were primarily focused upon improving the operating economies of the generating units and plants. Fossil-based generation technologies were well understood, and scale economies were easily accessible. The size of existing generating units and plants was increased to capture increasing returns to scale, thereby lowering average generation costs. Since generation constituted the major activity of the geographically isolated utility, average total costs also declined with plant scale. Regulators attempted to foster such growth. As a result, firm efficiencies were driven by generating plant efficiencies. The minimum efficient size of a particular firm was essentially determined by the efficiency of each of the utility's plants and the ability of the portfolio of plants to efficiently respond to the mix of baseload, intermediate load and peaking load in the local service territory.[4]

Over the past twenty-five to thirty years, however, a variety of technological and economic forces have altered these conditions. In the process, the relative predominance of the generation function in utility economics has diminished.

In terms of technological forces, the opportunity for scale economies in generation units and plants has essentially been exhausted. Indeed,

3. For example, the statutory language of the Public Utility Holding Company Act of 1935, Pub. L. No. 74-333, 49 Stat. 803 (codified at 15 U.S.C. §§ 79-79z-6 (1994)) [hereinafter PUHCA], makes it clear that the legislators believed that no real efficiency gains were possible by financially linking operating companies that were technologically separate and isolated. Indeed, the statute was enacted to avoid the economic and financial problems that arose in such financial and speculative linkages.

4. *See* Paul L. Joskow, *Inflation and Environmental Concern: Structural Change in the Process of Public Utility Price Regulation*, 17 J.L. & Econ. 291 (1974). Joskow argues that the pervasive presence of returns to scale in generation had a fundamental effect on the nature of electric utility regulation through the 1960s. During this period, the availability of scale effects allowed utilities to continually lower average costs. Public utility commissions were most interested in keeping regulated retail rates constant or slightly declining. Since their average costs of service declined with scale while their retail rates remained constant, utilities were able to increase profitability and effectively avoid rate of return regulation. Utilities asked for rate hearings infrequently. Regulatory commissions were not overburdened and followed a hands-off approach.

some existing fossil units and plants are now felt to be too large.[5] The scale of nuclear units has reached efficiency limits.[6] The recent experience of independent power producers with combined cycle gas turbines (CCGT) demonstrates that minimum efficient scale is achieved with fairly small units and plants.[7]

At the same time, profound economic changes have occurred and have contributed to limiting scale economies. The two most important economic changes have been the general inflationary pressures over 1975-1985, which raised the cost of capital, and the disequilibrium in fossil fuel markets initiated by OPEC activities in the 1970s. As a result of OPEC activities, the cost of fossil fuels rose significantly in the 1970s, and after demand adjusted to those increases, the prices of fossil fuels declined just as precipitously. The effects of these forces were substantial. The increases in the cost of capital made capital intensive projects less desirable. As a result, large scale generating plants, characterized by complex environmental regulation, became subject to severe financial diseconomies.[8] The escalation in fuel prices over the 1970s generally made power more expensive,[9] while the

5. Verne W. Loose & Theresa Flaim, 9 *Economies of Scale and Reliability: The Economics of Large Versus Small Generating Units*, 4 ENERGY SYS. & POL'Y 37 (1980). Loose and Flaim examine the relative costs of large and small generating units, taking into account both economies of scale and unit reliability. Larger units offer greater scale economies at the expense of greater capital investment for higher reserve margins. Using production cost simulations, the authors find that the higher reserve margins required for larger units outweigh their production savings. Installing several smaller units results in lower costs to the utility. They contend that scale economies are exhausted at unit sizes of 500 MW for fossil units.

Schroeder et al., *Flexibility of Scale in Large Conventional Coal-Fired Power Plants*, ENERGY POL'Y 127 (1981). Schroeder, Wiggins and Wormhoudt examine and contrast the possibility of configuring large coal-fired power plants with either large (800-1,300 MW) or small generating units (400-600 MW). They contend that the construction of large plants (1,500-5,000 MW) composed of small units yields two sets of benefits: those associated with large-plant scale economies and those associated with small-unit flexibility and reliability. The small units avoid reliability problems experienced with the larger units.

6. Carl Behrens, *Small Nuclear Power Plants: Financing Ease May Balance Scaling Factor*, 13 ENERGY POL'Y (UK) 360 (1985). Behrens contends that large nuclear units have become very difficult to finance for U.S. utilities. Using a simulation model for the New York Intertied System, he demonstrates that economies of scale of large plants (1200 MW) tend to be outweighed by financing difficulties that are avoided if small plants (400 MW) are constructed.

PAUL L. JOSKOW & RICHARD SCHMALENSEE, MARKETS FOR POWER: AN ANALYSIS OF ELECTRICAL UTILITY DEREGULATION (1983). Summarizing a variety of analyses, Joskow and Schmalensee claim that unit-level scale economies are exhausted at the 300-500 MW range for fossil-fuel units; 900-1200 MW for nuclear units; and 800 MW for fossil-based plants.

7. *See, e.g.*, Charles River Associates (CRA) Energy Ventures Analysis (EVA), *Beyond Speculation: Framing Scenarios of Gas Use for Power Generation*, Report to the Electric Power Research Institute, TR-102946 (Jan. 1996). The study indicates that CCGT units reach minimum efficient scale at 225-250 MW and that CCGT plants of 2-4 units (say 450-1000 MW) are optimal (MES) to exploit site economies.

8. Indeed, many economists argued that the cost of capital to utilities became greater than the regulated rate of return. As a result, no expansion of generating capacity (or any capacity) occurred.

9. These technological and economic forces, in turn, fundamentally altered the prevailing regulatory environment. The earlier profitability obtained through the exploitation of scale economies in the face of constant regulated retail rates disappeared. *See* Joskow, *supra* note 4. In the face of inflationary pressures and environmental concern, average generation costs and average total costs

subsequent decline in fossil fuel prices over the 1980s led to a variety of distortions in particular fuel markets.[10]

While scale effects have been limited since the 1960s at the generation level by this confluence of economic and environmental concerns, technological progress and scale effects at the other vertical stages of production have become important. Earlier in the century, the development of alternating current transmission extended the distance over which electricity could be economically transported. As a result, individual isolated plants (of minimum efficient size) could be connected into broader systems under the common ownership of a single firm. Improvements in transmission technology have continued to reduce transmission losses and lower transmission costs. More importantly, the computer revolution of the 1960s has allowed for substantially increased economies of coordination within broader transmission systems.

These related economic, technological and regulatory pressures have forced utilities to forego generation plant expansion and find methods of better exploiting existing power production within and without their service territories while coordinating that supply with spatially-dispersed load requirements. To do so, utilities have exploited *at the firm level* any remaining scale economies in generation, while, more importantly, exploit-

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began rising significantly in the late 1960s. With constant retail rates, utilities began losing money. Rate of return regulation became binding for the first time. There arose a massive demand for rate increases by the utilities, overwhelming public utility commissions accustomed to a quieter hands-off approach. The public began intervening in the rate hearings, demanding cost containment. A variety of statutory and regulatory changes were implemented to contain costs, initiate energy conservation, stimulate technological developments and alternative sources of energy.

See PAUL W. MACAVOY, ENERGY POLICY: AN ECONOMIC ANALYSIS (1983) (overview). *See also*, Paul L. Joskow & Paul W. MacAvoy, *Regulation and the Financial Condition of the Electric Power Companies in the 1970's*, 65 AM. ECON. REV. 295 (1975)(describing the financial distress of investor owned utilities (IOUs)); Paul L. Joskow, *Public Utility Regulatory Policy Act of 1978: Electric Utility Rate Reform*, 19 NAT. RESOURCES J. 787 (1979). Joskow describes the economic responses implemented into the Public Utility Regulatory Policy Act of 1978 (PURPA), Pub. L. No. 95-617, 92 Stat. 3117 (codified as amended at 16 U.S.C. §§ 2610-2645 (1994)).

10. For example, events in the U.S. natural gas markets over the 1980s have been well documented. These economic events accelerated the deregulatory initiatives begun in the late 1970s. The result was the restructuring of the gas industry as implemented primarily by the FERC through Orders Number 436, 500 and 636. These substantial economic and regulatory changes have obviously and pervasively impacted the economics and regulation of the electric power industry. These events have also impacted minimum efficient scale in the industry, given the reliance upon gas fired turbines for new capacity.

See Michael J. Doane & Daniel F. Spulber, *Open Access and the Evolution of the U.S. Spot Market for Natural Gas*, 37 J.L. & ECON. 477 (1994); Harry G. Broadman, *Elements of Market Power in the Natural Gas Pipeline Industry*, 7 ENERGY J. 119 (1986); Harry G. Broadman, *Competition in Natural Gas Pipeline Wellhead Supply Purchases*, 8 ENERGY J. 113 (1987); Glenn R. Hubbard & Robert J. Weiner, *Efficient Contracting and Market Power: Evidence from the U.S. Natural Gas Industry*, 34 J.L. & ECON. 25 (1991); Glenn R. Hubbard & Robert J. Weiner, *Regulation and Long-Term Contracting in U.S. Natural Gas Markets*, 35 J. INDUS. ECON. 71 (1986); J. Harold Mulherin, *Complexity in Long-Term Contracts: An Analysis of Natural Gas Contractual Provisions*, 2 J.L. ECON. & ORG. 105 (1986); J. Harold Mulherin, *Specialized Assets, Governmental Regulation, and Organizational Structure in the Natural Gas Industry*, 142 J. INST'L & THEORETICAL ECON. 528 (1986). These pieces provide greater discussion of the events in the gas industry.

ing those efficiencies attainable through the aggressive coordination of the generation, transmission and distribution functions.[11]

The efficiencies thereby attained have been informational and managerial. They result from integrating load planning for diverse groups of customers and coordinating both the operation and the planning/expansion of traditional and alternative generation and transmission capacity.[12] The following benefits result:[13]

1. Optimal Exploitation of Scale Economies Across all Plants

By providing the opportunity to economically move power over great distances, the high-voltage transmission system allows for consolidation of previously spatially-dispersed demands. The consolidated demand can be served by a relatively smaller number of larger, more efficient generating plants rather than a large number of small isolated plants. The result is greater exploitation of scale economies at the generating plant level for the entire system.

2. Improved System Reliability

Coordinated transmission planning, operation and interconnection make it possible to meet any particular level of system reliability with less generating capacity than would be required if previously isolated plants continued to serve isolated load centers.

3. Improved Energy Interchange

Interconnection of dispersed generating plants allows for coordinated economic dispatch through state-of-the-art computer technology. Aggregate system demand can thereby be met with the lowest-cost mix of generating capacity at any instant. Isolated plants serving isolated loads cannot take advantage of opportunities to generate power economically in nearby systems.

4. Load Diversity Economics

Demand patterns may differ sharply from area to area. They most certainly will differ somewhat. Such diversity allows for coordination economies. For example, one area may have a summer peak load demand while an adjacent area may have a winter peak. Computerized coordination of high-voltage transmission between these areas makes it possible to aggregate the loads and rationalize the construction and operation of the generation capacity to serve those loads. Service can be rendered jointly to these

11. Where such exploitation of scale and coordination economies has not occurred through common ownership, they have been partially captured through power pools.

12. By traditional generation facilities, I mean hydro-based, fossil-fuel and nuclear capacity. By alternative power sources, I mean PURPA-based conservation activities and independent power production.

13. JOSKOW & SCHMALENSEE, *supra* note 6.

diverse customers with significantly less generating capacity than would be required to meet the sum of the individual demands.

5. Maintenance Economies

All generating units must be shut down for maintenance. Nuclear units must be deactivated for refueling. Higher cost replacement energy is usually required during such maintenance periods. By coordinated scheduling of a large number of interconnected plants serving an aggregate regional load, the costs of planned outages can be reduced well below levels incurred by independently scheduling the maintenance of isolated plants.

6. Emergency Responses

Transmission facilities and coordinated operation of generation plants improve the ability of a system to respond to emergencies, to avoid loss of load and to reduce the duration of load losses that occur in emergencies within specific areas.[14]

7. Other Economies

Forecasts of future loads are more reliable when a large number of customers located in communities with differing economic conditions are planned jointly. More accurate load forecasting, in turn, permits better capacity planning. Furthermore, average cost reductions are possible when load management, conservation and environmental programs are coordinated and consolidated for diverse customer groups.

B. *Implications for Predicted Merger-Induced Efficiencies in Recent Mergers*

The profound economic, technological and regulatory changes of the last three decades have diminished the relative importance of the generation plant in determining the minimum efficient size of a utility.

Minimum efficient firm size today is determined by the coordination of a portfolio of generating plants and units of minimum efficient size integrated within transmission and distribution systems of minimum efficient size. This coordination is accomplished with modern management information systems. It takes account of demand diversity, load management and conservation programs and independent power production. In the process, firm level efficiencies are obtained *not only* from traditional scale effects *but also* from better management and coordination of diverse demands and supplies within the vertically integrated firm.

Utility mergers will produce efficiencies when they take advantage of these technological and economic realities. We may conclude therefore that horizontal mergers between firms specializing at one stage of produc-

14. Indeed, the initial efforts to expand power pooling coordination was a response to the significant outage in New York in 1965.

tion will offer fewer possibilities for efficiency gains. For example, the merger of two operating companies specializing in generation may produce little in the way of efficiency gains because the generating plants should already be at minimum efficient scale. On the other hand, mergers which extend the vertical reach of the merging firms will produce the efficiencies that result from increasing the scale of the generation, transmission and distribution *network* and the diversity of customers served.[15]

The predicted efficiency gains in Table 1 reflect these technological factors. The Table identifies the most significant merger and acquisition initiatives of the last two decades prior to the enactment of the Energy Policy Act of 1992 (EPAct).[16] Table 1 also presents the predicted (*by applicants*) merger-induced savings. The savings are expressed as a percent of the annual operating revenues at the time of the merger. They range from below 1% to a high of 5.4%.

The merger of Pacificorp with Utah Power and Light (UPL), for example, was predicted to produce the largest efficiency gains relative to current operations. This is not surprising. This merger allowed the two utilities to significantly rationalize the operation and expansion of generation capacity by interconnecting two diverse service territories. The customers of the two utilities have considerably different peaking characteristics. Pacific Power and Light (PPL—Pacificorp's operating subsidiary) is a winter-peaking utility while UPL is a summer peaking utility. Integration, therefore, was predicted to produce significant efficiency gains in power supply as a result of the following: 1) operation of the most efficient plants of the combined utilities to supply power to each of the service territories during the non-coincident seasonal peaks; and 2) the ability to defer construction of new generating capacity until the late 1990s.[17] Likewise, in the proposed merger between Southern California Edison Company (SCE) and the San Diego Gas and Electric Company (SDG&E), load diversity economies were also projected. However, both service territories exhibit summer peaks, making the difference between the peaks less dramatic and the pre-

15. Obviously, it is possible that some vertical mergers which are designed to exploit these efficiencies may be contrary to the functional unbundling and/or divestiture required by restructuring. I address this issue in Section IV. My concern here is critically assessing *ex ante* estimates of merger-induced efficiencies.

16. *See* EPAct, *supra* note 1. While this temporal truncation may be somewhat arbitrary, the mergers and acquisitions prior to 1992 were subject to a fairly consistent and potentially more stable regulatory regime and were scrutinized by a fairly consistent and potentially more stable set of principles and criteria.

Since 1992, the market has become more competitive and uncertain; the regulatory institutions and merger criteria have been in flux; and the reasons to and urge to merge have become more feverish. As a result, it may be argued that the efficiency studies undertaken in support of proposed mergers have become advocacy documents, more strategic and less scientific. I do not make that particular argument. However, I do contend that all *ex ante* efficiency studies must be critically scrutinized.

17. The specific estimates in Table 1 are taken directly from the FERC, Utah Power & Light Company, Pacificorp and PC/UP&L Merging Corporation, *Initial Decision of the ALJ Denying Proposed Merger*, 43 F.E.R.C. ¶ 63,030 (1988). These estimates were further evaluated (with all criteria) in 45 F.E.R.C. ¶ 61,095 (1988), *reh'g* 47 F.E.R.C. ¶ 61,209 (1989).

dicted efficiency gains relatively less substantial (2.0% of electric operating revenues).[18]

On the other hand, those mergers in Table 1 that do not exploit potential vertical efficiencies do not predict substantial merger savings. For

TABLE 1: SIGNIFICANT MERGER AND ACQUISITION INITIATIVES PRIOR TO THE ENERGY POLICY ACT OF 1992

Utilities	Year of Merger Approval/Rejection	Predicted Merger Savings Dollars*	Percentage
Mergers			
Eastern Gas and Fuel Associates, Boston Gas, Brockton Gas	1967	$290-$356	(<1%)
Hawaiian Electric, Hilo Electric	1970	$214	(<1%)
American Electric Power, Columbus and Southern Ohio Electric	1978	$49,500	(1.5%-2.6%)
Centerior Energy, Cleveland Electric Illumination, Toledo Edison	1986	$18,860	(1.0%)
Southern Company, Savannah Electric Power (SEPCO)	1988	$50,000	(<1%)
Pacificorp, Utah Power and Light (UPL)	1988	$113,000	(5.4%)
Southern California Edison (SCE), San Diego Gas and Electric (SDG&E)	Rejected 1991	$141,600	(2.0%)
Takeovers			
Eastern Utility Associates acquisition of Unitil and Fitchburg	1991	$8,500-13,200	(1.8%-2.8%)

Notes:
* Savings expressed in thousands of dollars annually.
** In parentheses, the annual savings are expressed as a percent of total annual operating revenues at the time of the merger.
Source: Arthur D. Little, Inc. [1990].

example, the Hawaiian Electric and Hilo Electric systems were not physically interconnected. The gains from vertical coordination were, therefore, non-existent. The only savings predicted in this merger, therefore, were those arising from the consolidation of such overhead functions as contracted engineering services, data processing for customer billing and accounting, and fuel oil procurement. Likewise, the predicted efficiency gains from the merger of Cleveland Electric Illuminating and Toledo Edison were primarily in the area of overhead consolidation. In both of

18. *See* SOUTHERN CALIFORNIA EDISON & SAN DIEGO GAS AND ELECTRIC COMPANY, FILINGS BEFORE THE PUBLIC UTILITY COMMISSION OF THE STATE OF CALIFORNIA, SYSTEMS OPERATIONS AND PLANNING: BENEFITS OF THE MERGER, April, 1989.

these mergers, predicted efficiency gains amount to 1% (or less) of annual operating revenues.[19]

Table 2 identifies significant mergers and acquisitions since the enactment of EPAct and summarizes *ex ante* estimates of merger-induced efficiencies *measured by labor savings alone.* For comparison, several of the mergers from Table 1 are included in Table 2. Because the labor savings estimated to be induced by each of these mergers takes no account of the substantial capacity and energy savings possible through merger (as identified in Section IIA above), labor savings estimates alone *cannot* provide a complete picture of merger-induced efficiencies. For example, for those mergers for which we do have comparable data (PPL/UPL and SCE/SDG&E), we find that predicted merger-induced labor savings differ substantially from predicted merger-induced total savings.[20] Without further analysis, it remains unclear whether predicted labor savings generally is a good or a poor estimate of total merger-induced savings. Because merger-induced labor savings do not capture all of the efficiencies identified in Section IIA, it is unlikely to provide an accurate *ex ante* evaluation of the efficiencies that will be induced by merger.

C. *Relevance to Recent Restructuring Proposals*

The recent regulatory impetus to restructure the electric power industry certainly has been shaped by the technological and economic forces described in Section IIA.[21] Most importantly, power generation can now

19. In particular, the total estimated annual savings recognized by the Securities and Exchange Commission (SEC) in the Cleveland Electric Illuminating and Toledo Edison merger were broken out as follows (in $millions): computer-aided drafting ($0.70), deferred generating capacity construction ($3.56), inventory and materials purchasing ($4.20), management information systems ($2.10), personnel consolidation ($7.20) and cost of capital savings ($1.10). *See* Arthur D. Little, Inc., *Evaluation of EUA's Proposed Acquisitions of Unitil and Fitchburg* (March 1990) (report to Gaston & Snow).

20. For example, we find that the applicants predicted an 11.50% reduction in personnel and a 5.4% reduction in total costs in the PPL/UPL merger. For the SCE/SDG&E merger, the applicants' predictions were 5.10% and 2.0% respectively. Hence, for these two mergers, predicted labor savings were more than double predicted savings overall.

In some mergers, the labor savings will dominate the total and may therefore be a good proxy. For example, in the case of the Hawaiian Electric/Hilo Electric merger (Table 1), the service territories are geographically distinct. In that case, as mentioned above, most of the savings must be labor savings. Likewise, the service territories of Public Service Company of Colorado and Southwestern Public Service Company (Table 2) are also geographically distinct and not directly interconnected. One will therefore expect that much of their predicted merger-induced savings will be labor savings.

21. I do not attempt to develop this topic in any detail here. However, I do explore the issues in somewhat more detail in Section IVB.

For some background concerning initial restructuring alternatives, see JOSKOW & SCHMALENSEE, *supra* note 6. The most recent U.S. proposals are found in the federal and state notices of proposed rule making; *see, e.g.*, Notice of Purposed Rulemaking, *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services By Public Utilities*, Docket No. RM95-8-000, 60 Fed. Reg. 17,662 (1996). California Public Utilities Commission (CPUC), *Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation: Proposed Policy Decision Adopting a Preferred Industry Structure, Proposal II* (proposed policy decision) [hereinafter PROPOSAL II]; CPUC, *Customer Choice Through Direct Access: Charting a Sustainable Course to a Competitive Electric Services Industry, Proposal I*

TABLE 2: SIGNIFICANT ELECTRIC UTILITY MERGER ACTIVITY SUBSEQUENT TO THE ENERGY POLICY ACT OF 1992.

Codes	Company 1	Company 2	Holding Co.	Position Reduction	Date	Status
PPL/UPL	Pacific Power and Light	Utah Power and Light	PacifiCorp	11.50%	1988	FERC approved. Effective 1/89.
SCE/ SDG&E	Sourthern California Edison	San Diego Gas and Electric		5.10%	1991	Rejected by CPUC, 5/91.
KCPL/KGE	Kansas City Power and Light	Kansas Gas and Electric		5.50%	1991	KCPL dropped hostile takeover bid.
KPL/KGE	Kansas Power and Light	Kansas Gas and Electric	Western Resources	6.60%	1991	FERC approved, 9/91.
NU/PSNH	Northeast Utilities	Public Service of New Hampshire	Northeast Utilities	0.90%	1992	FERC approved.
IPC/IPS	Iowa Power Company	Iowa Public Service	Midwest Resources	5.80%	1992	FERC approved, 7/92.
IPL/PSI	Indianapolis Power and Light	PSI Energy		9.60%	1993	Unsuccessful hostile takeover bid by IPALCO.
ETR/GSU	Entergy	Gulf States Utilities		na	1993	FERC approved, 12/93.
CSW/EPE	Central and Southwest	El Paso Electric		2.60%	1995	Terminate merger process, 6/95.
CE/TE	Cleveland Electric	Toledo Edison	Centerior	3.40%	1994	Technical merger of 2 subsidiaries; 1986 merger created Centerior.
CGE/PSI	Cincinnati Gas and Electric	PSI Energy	CINergy	4.20%	1994	FERC approved, 10/94.
PECO/DPLC	Philadelphia Electric (Conowingo Power)	DelMarVa Power			1995	FERC approved, 5/95.
MWR/IIGE	Midwest Power Systems	Iowa-Illinois Gas and Electric	MidAmerican Energy Co.	6.00%	1995	FERC approved, 6/95.
PECO/PPL	Philadelphia Electric Company	Pennsylvania Power and Light		9.50%	1995	Termination of merger process, 10/95. Offers not accepted.
WWP/SPR	Washington Water Power	Sierra Pacific Resources	Resources West Energy	8.50%		Pending.
NSP/WEC	Northern States Power	Wisconsin Energy Corp.	Primergy Corp.	10.10%		Pending. Announced 5/95.
UE/CIPS	Union Electric Company	Central Illinois Public Service Company		3.40%		Pending. Announced 8/95.
PSCO/SPS	Public Service Company of Colorado	Southwestern Public Service Company		8.80%		Pending
IEL&P/IS	Iowa Electric Light and Power	Iowa Southern Utilities	IES Industries	na		Pending at FERC. Approved by Iowa Utilities Board, 8/95.
PEPCO/BGE	Potomac Electric Power	Baltimore Gas and Electric				Pending. Announced 9/95.
PSPL/WEC	Puget Sound Power and Light	Washington Energy Company				Pending. Announced 19/95.

Sources: Hawes [1995]
McGraw Hill Electric Utility Week
Inside FERC, various issues
Electricity Journal, October 1995

be provided through a distributed competitive market structure, given the fact that minimum efficient scale and minimum viable scale have continued to decline in generation and the concomitant fact that independent power production has been further stimulated by the decline in natural gas prices. However, the ability of generating companies to compete in the restructured world will be importantly conditioned by their access to the transmission grid. This dependence on transmission is important because many of the technical system efficiencies that remain to be exploited are vertical efficiencies involving the coordination of generation with demand.

In the restructured world, transmission and distribution will remain natural monopolies. Hence, they will need to be regulated, presumably through incentive-based procedures. Since competitive generation will require nondiscriminatory open access to the regulated transmission network, a variety of alternative proposals to regulate the transmission authority have been proffered to assure such access. The operating arrangements that are ultimately adopted for the transmission authority will have a substantial impact upon the economic structure, conduct and performance of the participants in this market.[22]

However the regulation of the transmission authority is implemented, a fundamental tenet of all the restructuring proposals is that the transmis-

(Alternative), Proposal and Recommendations of Commissioner Jessie J. Knight, Jr. to the Commission, the Legislature and the Public (May 24, 1995) [hereinafter PROPOSAL I (ALTERNATIVE)]; CPUC, *Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation: Memorandum of Understanding (MOU) on Joint Recommendations Among California Manufacturers Association, California Large Energy Consumers Association, Independent Energy Producers, Californians for Competitive Electricity and Southern California Edison Company* (September 14, 1995) [hereinafter PROPOSAL I].

Stated simply, in all restructuring scenarios, generation, transmission and distribution assets are unbundled, either functionally or corporately (i.e., divested). All independent generating facilities are assured of non-discriminatory open access to the transmission system, in order to serve any and all customers (wholesale and/or retail) who are assured of the freedom to choose their generation company.

Specific restructuring proposals differ on the institutional and operational characteristics of the transmission system; on the treatment of stranded assets; on the methods through which functional unbundling is implemented; and on the time frame in which restructuring is completed.

Raymond Hartman and Richard Tabors identify and discuss the economic effects of alternatively proposed restructuring arrangements more fully. *See* Raymond S. Hartman & Richard D. Tabors, *Optimal Operating Arrangements in the Restructured World: Economic Issues, Working Paper, Laboratory for Electromagnetic and Electronic Systems, Massachusetts Institute of Technology*, WP 95-001 (1995). David Newbury, *Power Markets and Market Power*, 16(3) ENERGY J. 39 (1995). *See also* Richard J. Green & David Newbury, *Competition in the British Electricity Spot Market*, 100 J. POL. ECON. 929 (1992), examine the effects of a specific restructuring design—the experience in the United Kingdom. *See* Schroeder Amundsen & Balbir Singh, *Developing Futures Markets for Electricity in Europe*, 13(3) ENERGY J. 95 (1992); Erling Diesen, *Norway: The Norwegian Electricity Industry—A Deregulated Market in a Regulated Europe*, 45 REVUE DE L'ENERGIE 464 (Paris, Annie 1994); and Per A. Loken, *Experience with Deregulation in Norway*, 15 MOD. POWER SYS. 23 (1995) (These works examine the effects of an alternative restructuring design.).

22. A variety of alternative operating arrangements are possible, ranging from a system of pure mandatory pooling and a system of pure bilateral transactions. As evidenced in the UK, the selection of the proper operating arrangement is quite important overall. However, I do not explore these alternatives here because they are not crucial to the topic explored in this paper. For greater discussion, see HARTMAN & TABORS, *supra* note 21.

sion authority (however institutionalized)[23] has no financial interest in the sources of generation or in wholesale or retail distribution. This tenet obviously has implications for merger policy. The necessity for functional unbundling will need to be carefully weighed against the technological efficiencies that can be gained through vertically coordinating generation with demand. I address these issues in Sections III and IV below.

III. A Cost-Based Methodology for Measuring Scale and Scope Economies in Electric Utilities

A. *Point of Departure: The Inadequacy of Ex Ante Efficiency Studies*

While the relative size of the predicted efficiency gains in Table 1 accord with the operational realities of vertically-integrated electric utilities, it remains unclear whether *any* of the predicted efficiency gains will actually be realized. Likewise, any estimate of merger-induced savings, like those in Table 2, that focuses exclusively upon labor savings will be incomplete and misleading because it will ignore the operational (capacity and fuel) efficiencies identified in Section IIA.

More importantly, all of the estimates presented in Tables 1 and 2 are *ex ante* estimates developed by the merger applicants in order to advocate their proposed merger before the relevant regulatory bodies. Hence, by their very nature, they are likely to be affected by strategic posturing and hopeful expectations. Before they are accepted as veritable, they must be critically scrutinized.

I propose such agnosticism because there exists considerable evidence[24] that the *ex ante* analyses of merger-induced efficiencies are incor-

23. Each alternative operating arrangement (whether a system of pure mandatory pooling, pure bilateral trading or a hybrid of the two) calls for a different design of the Independent System Operator (ISO). However, they all require arms-length transactions between the ISO and the buyers and sellers of power, whether those arms-length transactions are accomplished through functional unbundling or complete divestiture.

24. *See* Richard E. Caves, *Mergers, Takeovers, and Economic Efficiency: Foresight vs. Hindsight*, 7 INT'L J. INDUS. ORGANIZATION 151 (1989); A.S. Dewing, *A Statistical Test of the Success of Consolidations*, 36 Q.J. ECON. 84 (1921); FIRST MANHATTAN CONSULTING GROUP WITH THE BANK ADMINISTRATION INSTITUTE, CENTER FOR BANKING ISSUES AND STRATEGIES, ANALYZING SUCCESS AND FAILURE IN BANKING CONSOLIDATION: THE IMPLICATIONS FOR BANK ACQUISITION STRATEGIES (1990); BENTON E. GUP, BANK MERGERS: CURRENT ISSUES AND PERSPECTIVES (1989); Raymond S. Hartman, *Surrebuttal Testimony on Econometric Analysis of Merger Impacts, Report to the Division of RatePayer Advocates of the California Public Utilities Commission on The Proposed Merger of Southern California Edison Company and San Diego Gas and Electric Company*, Exhibit 10,511, Application 88-12-035 (July 1990); Thomas F. Hogarty, *Profits From Mergers: The Evidence of Fifty Years*, 44 ST. JOHN'S L. REV. 378 (Special Edition) (1970); GEOFFREY MEEKS, DISAPPOINTING MARRIAGE: A STUDY OF THE GAINS FROM MERGER (1977); Dennis C. Mueller, *Mergers and Market Share*, 47 REV. ECON. & STAT. 259 (1985); Dennis C. Mueller, *Mergers—Causes, Effects and Policies*, 7 INT'L J. INDUS. ORGANIZATION 1 (1989); DAVID J. RAVENSCRAFT & F.M. SCHERER, MERGERS, SELL-OFFS AND ECONOMIC EFFICIENCY (1987); and David J. Ravenscraft & F.M. Scherer, *The Profitability of Mergers*, 7 INT'L J. INDUS. ORGANIZATION 101 (1989). These studies examine the performance of the merged firms, *ex post*, or after the merger has been consummated and has had a chance to prove itself. The studies use a variety of performance criteria, including profitability, productivity and market share. It should be added that this literature is recent and moot.

rect for most mergers, whether in the utility industry or elsewhere.[25] The accuracy of *ex ante* measures is found to be surprisingly and consistently inadequate. *Ex post* analysis of merger performance indicates that the majority of *ex ante* studies developed to assess merger-induced efficiencies are incorrect and over optimistic. It appears to be true for efficiency studies, productivity studies and event studies. This seems to be true for mergers in this country and internationally; for mergers in this country over the last century; for mergers in competitive sectors and for mergers in recently deregulated sectors. Almost all mergers *are undertaken* with the *ex ante* prediction that benefits and efficiencies will occur. However, *ex post*, the vast majority (60%-80%) of mergers can be characterized as unsuccessful.[26]

The vast majority of mergers fail to achieve the expected benefits identified in pre-merger *ex ante* productivity/efficiency studies for two principal reasons:[27]

1) the gains expected from the merger are usually overestimated in the *ex ante* studies or they are nonexistent; and
2) the actual costs and difficulties of integrating the merging firms are usually underestimated in the *ex ante studies*.

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25. The industries examined in the studies cited in the preceding footnote are quite diverse. Some are capital intensive and some are not. Hence, the conclusions concerning *ex post* performance are fairly general and, I contend, relevant to the electric power industry.

However, the *ex post* study most relevant to mergers in the electric power industry would focus upon mergers in that industry. Such a study has not been performed to date, simply because there have not been a sufficient sample of mergers to support such a statistical study, until recently.

This author is currently performing such a study. The study compiles and examines two sets of *ex ante* predictions of merger-induced efficiencies—those introduced by the applicants (i.e., standard efficiency/productivity studies) and those expressed by the stock market at the time of the merger announcement (i.e., event studies). The study also compiles and examines several measures of *ex post* merger success, including measures of actual productivity increases, profitability, cash flow, and whether the merged firm fulfilled rate commitments. The *ex post* performance will be compared with the *ex ante* predictions, in order to assess the reliability of the *ex ante* predictions.

26. The best method for critically assessing whether efficiency gains, predicted *ex ante*, have been attained through utility mergers is a retrospective (or *ex post*) analysis of the specific utility mergers. Unfortunately, until recently, the sample of utility mergers and the supporting data have not been sufficient to draw general conclusions. There does exist *ex post* information summarizing the performance of mergers for a large number of firms in a broad cross-section of other industries. This data forms the basis of the research cited in the previous footnote.

27. As a result, it is fair to say that if the efficiency gains predicted by the applicants for a utility merger are small, the merger will probably fail. The reason is that it is most likely that some of the merger gains will simply not occur and that a variety of integration costs have probably been ignored. Examining the mergers in Table 1 in this context, it is fair to say that those mergers will probably fail for which the expected savings are less than 1% of annual operating revenues. This conclusion is importantly refined below.

Given this observed pattern of failure, regulators should address the possibility that utility mergers are driven by non-efficiency motives. Possible motives include enhancement of market power; transfer of wealth from tax payers, bond holders, employees, suppliers, and/or communities; empire building; simple entrepreneurial over optimism; and/or regulatory evasion. At the same time, regulators should assess whether a particular merger may fail *ex post* for any of the reasons found to cause other merger failures. Possible reasons for merger failure include managerial control loss, conflict in corporate cultures, the winner's curse and unsupported over optimism.

Given the serious questions concerning the accuracy of *ex ante* efficiency claims generally, alternative analytic methods are needed to assess the accuracy and reliability of the *ex ante* efficiency claims of merger applicants. While it has been argued that the majority of mergers do indeed fail, some mergers do succeed. They succeed when the predicted efficiency gains are indeed attainable and when there are no substantial unanticipated transition costs. Regulators and the courts will be better able to differentiate between the few mergers that do succeed and the many that fail if they can better assess the credibility of the predicted efficiency gains and integration costs. As will be discussed in the remainder of this Section, econometric or statistical cost analysis is an appropriate analytic method to critically assess these *ex ante* efficiency claims.

B. *Overview of the Methodology*

Section IIA identified the efficiencies that are possible through utility mergers. Sections IIB and IIIA indicated that regulators would be misguided to rely entirely upon the merger applicants' *ex ante* predictions of merger-induced efficiency gains.

In this Section and Section IIIC, I develop information that can be used by regulators and the courts to assess the credibility of specific *ex ante* efficiency predictions. I also indicate how the information can be used.

The vertical structure of a utility allows for certain efficiencies or economies, the exploitation of which reduces the average cost of delivering electricity.[28] In order to assess whether such efficiencies are induced by a specific merger, we require an analytic methodology which relates the costs of generating and delivering electricity to the vertical characteristics of the industry. Specifically, firms have combined through merger to produce larger economic entities with increased scale, broadened scope and/or increased customer density. The ultimate efficiency effects of a merger will therefore depend upon the presence of scale, scope and/or density economies. The ultimate size of the efficiency gains will depend upon the following: the initial size and characteristics of the merger candidates; the characteristics of their service territories; and the relative increase in scale, scope and density induced by the merger.

In order to assess whether such efficiencies are induced by a specific merger, we require an analytic methodology which relates the costs of generating and delivering electricity to the vertical characteristics of a utility. Statistical cost analysis does so. The use of statistical cost analysis to identify and quantify the nature of production and cost is well established.[29]

28. Properly designed, open access will accentuate certain opportunities for efficiency gains.

29. The contribution of contemporary statistical cost analysis in a variety of regulated and unregulated industries is incontrovertible. The foundations for this analysis have been duality theory and flexible functional forms. *See, e.g.*, William E. Diewert, *Applications of Duality Theory*, *in* FRONTIERS OF QUANTITATIVE ECONOMICS (Michael D. Intriligator & David A. Kendrick eds. 1974); PRODUCTION ECONOMICS: A DUAL APPROACH TO THEORY AND APPLICATIONS (Melvyn Fuss & Daniel McFadden eds. 1978) (addressing duality theory). *See e.g.*, Laurits R. Christensen et. al, *Transcendental Logarithmic Production Frontiers*, 55 REV. ECON. & STAT. 28 (1973) (addressing

Likewise, the notions of scale, scope and density economies that are quantified by statistical cost analysis are fairly well understood. I therefore discuss them only briefly.

Economies of scale arise when average costs decline with size. If the average cost of generating electricity declines with the size, *or scale*, of the unit or plant, increasing returns to scale in generation are present. As discussed above, however, economies of scale at the firm level are most important today. Utility companies currently seek to exploit scale economies by sizing and integrating a portfolio of efficient plants and units within a transmission and distribution system of minimum efficient size. By increasing the size of its integrated generation, transmission and distribution network, a utility can increase and consolidate more spatially-dispersed demands, thereby further rationalizing its generating capacity and operations. For the larger networks, average delivered cost of electricity is lowered and increasing returns to scale are exploited.

Whether the frame of reference is the plant or firm, we can more formally characterize the notion of scale economies as follows. If total production costs increase proportionally *less* than the increase in the relevant measure of scale, average costs fall and increasing returns to scale occur. If, on the other hand, total costs increase proportionally *more* than the relevant measure of scale, average costs rise and decreasing returns to scale occur. At the plant level, scale is usually measured by capacity or electric-

functional forms). Applications are manifold. In addition to the cost studies discussed in this Section, the references identify, as selected examples, statistical cost analyses performed in the telecommunications industry. *See, e.g.*, David S. Evans & James J. Heckman, *Natural Monopoly* (Chapter 6), *Multiproduct Cost Function Estimates and Natural Monopoly Tests for the Bell System* (Chapter 10), *in* BREAKING UP BELL: ESSAYS ON INDUSTRIAL ORGANIZATION AND REGULATION (David S. Evans ed. 1982); Michael Denny et. al, *The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, With an Application to Canadian Telecommunications*, *in* PRODUCTIVITY MEASUREMENT IN REGULATED INDUSTRIES (Thomas Cowing & Rodney Stevenson eds. 1981). *See, e.g.*, Ann F. Freidlaender et. al, *Costs, Technology and Productivity in the U.S. Automobile Industry*, 14 BELL J. ECON. 1 (1983) (the auto industry); Richard H. Spady & Ann F. Friedlaender, *Hedonic Cost Functions for the Regulated Trucking Industry*, 9 BELL J. ECON. 159 (1978) (the regulated trucking industry); A. N. Berger et. al, *Competitive Viability in Banking: Scale, Scope and Product Mix Economies*, 20 J. MONETARY ECON. 994 (1987) (the banking industry); Douglas W. Caves et. al, *U.S. Trunk Air Carriers, 1972-1977: A Multilateral Comparison of Total Factor Productivity*, *in* PRODUCTIVITY MEASUREMENT IN REGULATED INDUSTRIES (Thomas Cowing & Rodney Stevenson eds. 1981) (the airlines industry); Douglas W. Caves et. al, *Productivity Growth, Scale Economics, and Capacity Utilization in U.S. Railroads, 1955-1974*, 71 AM. ECON. REV. (1981) (the railroad industry); J. R. Norsworthy et. al, *Productivity and Cost Measurement for the United States Postal Service: Variations Among Regions*, *in* TOPICS IN REGULATORY ECONOMICS AND POLICY SERIES (Michael Crew ed. 1991) (U.S. Postal Service). Furthermore, the techniques have not been limited to the learned journals. *See, e.g.*, Division of Ratepayer Advocates, California Public Utilities Commission, *Qualification and Prepared Testimony of Division of Ratepayer Advocates for Pacific Gas & Electric Company General Rate Case, Test Year 1990*, Application No. 88-12-005 (March 1988); Division of Ratepayer Advocates, California Public Utilities Commission *Revised Analysis of Productivity for The Southern California Gas Company*, Application 88-12-047 (April 1989); California Public Utilities Commission, Public Staff Division, *Analysis of Productivity for Southern California Edison Company General Rate Case, Test Year 1988*, Application 86-12-047 (March 1987); Southern California Edison, *Filings before the California Public Utilities Commission, Workpapers for the 1988 Test Year General Rate Case*, SCE-17, Application 86-12-047 (Dec. 1986).

ity generated. At the firm level, scale is measured by net generation, total sales, total generation capacity and/or total number of customers served.

Scope economies are defined to be those that arise as a result of increasing the variety of customers served. Because of the focus on customer diversity, scope economies are relevant only at the firm level. For a utility, customer variety is reflected by its mix of sales to different customer classes. The simplest definition of alternative customer classes includes retail electricity customers (residential, commercial and industrial), wholesale electricity customers and gas customers. More refined customer class definitions are possible.

Several real efficiencies arise with increasing customer diversity. First, the utility is able to distribute joint and common costs across a broader range of customers, where joint and common costs include such things as meter reading equipment, staff, customer service and corporate management. Second, and more importantly, the utility is better able to balance the peaking characteristics of customer classes in different areas, as described in Section IIA.

The extent to which customer diversity lowers average cost will be a measure of resulting diversity economies. If total production costs increase proportionally *less* than the increase in relevant measures of customer diversity, diversity economies, or scope economies, are operative. If, on the other hand, total costs increase proportionally *more* than customer diversity, scope diseconomies are present. Two alternative measures of customer diversity include the composition of customers by rate class (residential, commercial, industrial and wholesale customers) and by energy source (electricity and gas customers).

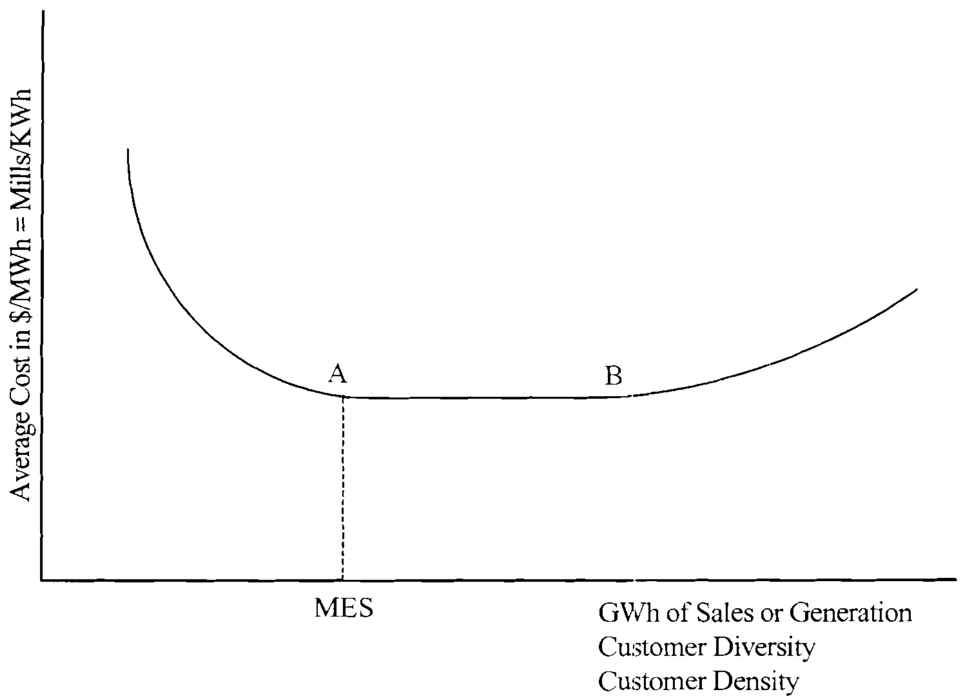
Once transmission and distribution costs are included at the firm level, it is necessary to consider the density of the customers in the service territory in order to assess the presence of density economies. Increasing customer density can lower costs by economizing on the transmission and distribution costs embodied in circuit miles and structure miles of transmission lines, transformers and substations. For example, for the same level of output or scale, the costs of supplying customers in Utah or in New Jersey will be quite different given differences in density.

The effect of density upon costs can also be stated simply. If total production costs increase proportionally less than the increase in the relevant measures of customer density, density economies are operative and increasing returns to density exist. If total costs increase proportionally more than customer density, density scale diseconomies are present and decreasing returns to density exist. Alternative measures of customer density include customers per square mile of service territory, the composition of customers by rate class and/or the mix of transmission capacity by low-voltage and high-voltage capacity lines.

Figure 1 provides a traditional representation of scale, scope and density economies using a firm-level average total cost curve (ATC). If the X axis represents utility size, then increasing returns to scale exist up to point A, the minimum efficient size (MES) of the firm. Constant returns to scale operate between points A and B, and decreasing returns to scale set in beyond point B. If, on the other hand, the X axis represents a utility characteristic, such as customer density or customer diversity, Figure 1 indicates that increasing returns to density or diversity operate until point A while decreasing returns set in at point B.

Statistical cost analysis allows the policy maker to identify and quantify ATC in Figure 1 and the implied scale, scope and density economies. The efficiency effects of a given merger can then be identified using ATC. To reiterate, these effects will depend upon the initial size and characteristics of the merger candidates (i.e., their initial positions on ATC in Figure 1); the characteristics of their service territories; and the relative increase in scale, scope and density induced by the merger (i.e., the final position of the merged utility on ATC in Figure 1).

FIGURE 1: AVERAGE TOTAL COST FOR THE FIRM



C. Formal Statistical Cost Analysis: A Summary of Results

The preceding discussion was generic. In this section, the discussion is more specific. I review a body of statistical cost analyses which actually quantify the scale, scope and density effects.

The relevant studies are listed in Table 3. Each study applies statistical cost techniques to a body of data for a representative group of utilities and identifies cost patterns for that group. The analyses relate utility costs to various measures of utility size (scale), customer scope, and customer density. Standard regression techniques are used to estimate the relationships. The statistical results indicate whether and by how much scale, scope and density lower electricity costs. The data sets used in the analyses represent time periods from 1970 through 1987.[30] The cost specifications and regression techniques are state-of-the-art.

All of the analyses examine firm-level economies. Some examine scale economies for generation activities within the firm. Others examine scale economies for all activities including generation, transmission, distribution and managerial. Scale effects are alternatively measured by the generation capacity of the firm (in megawatts—MW), the net generation of energy by the firm (in gigawatthours—GWH), or the sales of energy by the firm (in GWH). Some of the studies are concerned with scope effects, focusing on combination gas and electric utilities or electric utilities serving different mixes of retail and wholesale customers. One study examines density economies.

Almost all of the studies define costs to include variable costs (labor, fuels and materials) and capitalized fixed costs. Most studies examine total costs. Two studies disaggregate costs to functional areas, including generation, transmission, distribution, customer service, sales and administrative.

Despite the wide variety of time periods and sample utilities reflected in the alternative data bases, the conclusions of the statistical cost analyses are quite robust. All of the studies find significant increasing returns to scale in electricity for smaller utilities and constant or decreasing returns to scale for large utilities. Minimum efficient firm size (MES) for the bulk of the studies is in the range of 2,000-4,000 MW of capacity; 9,000-30,000 GWH of net generation; and 10,000-35,000 GWH of sales.[31]

Turning to the specific studies, Atkinson and Halvorsen[32] analyzed the generation costs of 123 privately-owned utilities in 1970. They related total generation costs to scale (GWH generated by fossil-fuel capacity), the cost of labor services, fuel costs and the cost of capital. Because they did not include transmission and distribution costs, their analysis provided estimates of firm-level scale economies in generation only. Using their estimated results, the authors indicated that the firm size at which scale economies are exhausted is approximately 50,400 GWH.

Christensen and Greene[33] represent the earliest applications of state-of-the-art statistical cost analysis to U.S. electric utilities. They estimated economies of scale in generation for a cross section of 124 firms/holding

30. The econometric studies cited in Table 3 comprise those known to the author. There has been little additional econometric work performed since 1990 for two reasons: 1) the conclusions from the preceding work seem to be fairly robust; and, 2) regulatory bodies have been less willing to invest the resources required to support additional work.

31. Some of the studies estimate MES in terms of energy (GWH); others estimate MES in terms of power (MW). Throughout this section, I translate power into energy assuming a 55% load factor, which is fairly representative for the historical period.

32. Scott E. Atkinson & Robert Halvorsen, *Parametric Efficiency Tests, Economies of Scale, and Input Demand in U.S. Electric Power Generation*, 25 INT'L ECON. REV. 647 (1984).

33. Laurits R. Christensen & William H. Greene, *Economies of Scale in U.S. Electric Power Generation*, 84 J. POL. ECON. 655 (1976); Laurits R. Christensen & William H. Greene, *An Econometric*

companies in 1955 and 114 firms/holding companies in 1970. Their functional specification and data were the same as those used by Atkinson and Halvorsen.[34] By 1970, the authors found that the bulk of U.S. electricity generation was by firms operating in the essentially flat area of the average cost curve (between points A and B in Figure 1). In 1970, they estimate that MES (point A) was 19,800 GWH or 4,100 MW, assuming 55% load factor. Point B is estimated to be 67,100 GWH. While their average cost curve is essentially flat over the range of 19,800 - 67,100 GWH,[35] the scale of operations for which average cost attains its true minimum is 35,000 GWH.

In their 1978 effort, Christensen and Greene[36] extended their 1976 analysis to assess the effects of power pooling on scale economies. They introduce power pool and regional effects by incorporating dummy variables into their 1976 cost specification. The dummy variables allow for nine regional designations and five power pool designations. The power pool dummy variables categorize each sample utility as belonging to one of the following groups: firms unaffiliated with any pool; firms affiliated with loose pools (those neither commonly owned nor centrally dispatched); firms commonly owned but not centrally dispatched; firms centrally dispatched but not commonly owned; and finally, firms affiliated with tight pools (those which are centrally dispatched and commonly owned).

The authors found that membership in power pools does not lower costs in any statistically significant fashion.[37] Their estimate of MES did not change much from their 1976 effort. They concluded that mergers among small firms make sense, while mergers among large firms should be prohibited. They also concluded that power pools did not seem to offer any real alternative to mergers, since pooling did not, in general, lower costs in their analysis.

Hartman, in his *Prepared Direct Testimony* submitted to the California Public Utilities Committee (CPUC),[38] and *Surrebuttal Testimony on Econometric Analysis of Merger Impacts*,[39] examined labor costs and non-labor overhead costs for 181 utility operating companies in 1987.[40] In *Sta-*

Assessment of Cost Savings from Coordination in US Electric Power Generation, 54 LAND ECON. 139 (1978).

34. Atkinson & Halverson, *supra* note 32.

35. Average cost is not statistically different over that range of generation.

36. Christensen & Greene, *supra* note 33.

37. However, it must be kept in mind that their power pool designations are based upon 1970 information. The characteristics and membership of some pools have changed since then.

38. Raymond S. Hartman, *Prepared Direct Testimony on Revenue Requirements Impacts*, REPORT TO THE DIVISION OF RATEPAYER ADVOCATES OF THE CALIFORNIA PUBLIC UTILITIES COMMISSION ON THE PROPOSED MERGER OF SOUTHERN CALIFORNIA EDISON COMPANY AND SAN DIEGO GAS AND ELECTRIC COMPANY, CHAPTER II, EXHIBIT 10,500, Application 88-12-035, (Feb. 1990).

39. *See* Hartman, *supra* note 24.

40. *See* Hartman, *supra* note 38. He also examines costs for the following specific categories of labor and non-labor overhead costs: Labor—production, transmission, distribution, customer accounts, customer service and information, sales, and administrative and general; and Non-labor Overhead—rents, advertising expenditures, office supplies, property insurance, franchise requirements, and regulatory commission expenses.

tistical Cost Analysis of the Electric Utility Industry,[41] he examined the total costs for the same set of operating companies. In all three cases, his cost variable includes all electric utility operations (generation, transmission and distribution). In the three efforts, he relates electric costs to the following: a variety of overall firm characteristics, including participation in power pools; the characteristics of the generation, transmission and distribution activities of the firms; the customer service activities of the firm; the extent of gas sales; and the reliance on purchased power.[42] Because they were developed as part of several merger cases, the Hartman analyses test a variety of specifications of the cost curve, in order to assess the robustness of the conclusions. He tests both sales and generation of electricity as measures of scale and finds the results to be corroborative. The MES results in terms of sales are reported in Table 3.

For the most part, Hartman's estimated MES for labor costs and for total costs for a variety of specifications of the cost curve are found to lie in the range of 20,000 to 40,000 GWH of sales. For total costs, Hartman, in *Statistical Cost Analysis*, corroborates the power pool conclusions of Christensen and Greene.[43] In particular, none of the Christensen and Greene power pool designations are statistically significant. Hence, their power pool conclusions for 1970 also hold for 1987. However, Hartman, in *Statistical Cost Analysis*, includes an additional power pool designation not included by Christensen and Greene.[44] That designation identifies utilities that are commonly-owned through a holding company *and* still part of a larger, centrally-dispatched power pool (holding companies within NEPOOL). These companies do reveal *differential* cost behavior which is statistically suggestive (significant at the 80% level). For these companies, MES is achieved much sooner—at 12,000 GWH of sales.

Huettner and Landon, in an article published in the *Southern Economic Journal*,[45] specify and estimate cost curves for operating and capital costs for the following major categories of utility costs: generation, transmission, distribution, administration, customer accounts and sales. As with the statistical cost analyses of other authors, Huettner and Landon's cost regressions include scale effects and such factor costs as wages, fuel costs and capital costs. The authors also attempt to include information on dif-

41. Raymond S. Hartman, *Statistical Cost Analysis of the Electric Utility Industry* (App. B), *in* EVALUATION OF EUA'S PROPOSED ACQUISITIONS OF UNITIL AND FITCHBURG, Report to Gaston and Snow (Arthur D. Little, Inc., Mar. 1990).

42. In particular, the firm characteristics include regional location, extent of vertical integration, participation in power pools and holding companies, annual investment activity and factor costs. The production-related factors include generation and sales of electricity, sales of gas, electric capacity utilization, the mix of generation capacity by fuel used, and the importance of purchased power. The transmission-related and distribution-related factors include miles and capacity of lines, plant and equipment capacity, customer mix and customer density. Customer service characteristics include the mix between wholesale and retail customers and the number of customers both by class and in aggregate.

43. *See* Hartman, *supra* note 41; *see also* Christensen & Greene, *supra* note 33.

44. Hartman, *supra* note 41.

45. David A. Huettner & John H. Landon, *Electric Utilities: Scale Economies and Diseconomies*, 44 S. ECON. J. 883 (1978).

TABLE 3: ECONOMETRIC ANALYSIS REVIEWED

Study	Data Base	Costs Analyzed	MES	
1. Atkinson and Halvorsen [1984]	123 fossil-fuel, steam-powered utilities in 1970	Generation Costs	50,400 GWh*(10,500 MW)	
2. Christensen and Greene [1976, 1978]	114 fossil-fuel, steam-powered utilities in 1970	Generation Costs	19,800 GWh*(4,100 MW)**	
3. Hartman [1990]	181 electric utilities in 1987	Total Costs	Labor Cost: [1990c]	
		Labor Costs	Semilog:	20,452 GWh
		Nonlabor Overhead Costs	Semilog:	30,256 GWh
			Log-log:	11,731 GWh
			With Regional Effects:	30,256 Gwh
			With Nuclear Focus:	54,624 GWh
			With Production Technology Focus:	38,783 GWh
			Alternative Wage Definition***	
			Semilog:	27,990 GWh
			Semilog:	24,226 GWh
			Labor Cost: [1990a]	
			Semilog:	46,000 GWh
			Total Costs: [1990b]	
			Overall:	38,200 GWh
			With Power Pool Effect:	12,000 GWh
4. Huettner and Landon [1978]	74 fossil-fuel, steam-powered utilities in 1971	Operating Costs and Capital Costs in:	Production:	1,600 MW (7,700 GWh*)
		Generation	Distribution:	2,600 MW (12,500 GWh*)
		Transmission	Administrative:	2,500 MW (12,000 GWh*)
		Distribution	Customer Accounts:	1,700 MW (8,200 GWh*)
		Sales	Total:	1,600 MW (7,700 GWh*)
		Customer Accounts		
		General Administrative		
5. Karlson [1986]	28 coal-fired utilities in 1978	Uses a Production Function	At least 33,400 GWh sold	
6. Mayo [1984]	131 electric utilities, 20 gas utilities and 49 combined utilities in 1979	Total Costs of Gas and Electricity Operations	4,300 - 9,400 GWh sold, gas and electricity together: 34,000 GWh sold, electricity specific	
7. Roberts [1986]	65 electric utilities in 1978	Total Costs of Electricity Operations	Report increasing returns to scale to consumption per customer; constant returns to customer density	
8. Sing [1987]	34 electric utilities, 31 gas utilities and 43 combination utilities in 1981	Total Costs of Gas and Electricity Operations	At least 11,200 GWh sold	
9. Stevenson [1982]	79 electric utilities, 25 of which are combination utilities, over 1964-1972	Generation Costs	Not reported	

Notes:
* MES expressed in GWH generated. Where necessary, all output is translated into capacity using the national average load factor of 55%.
** Average cost is not statistically different between 19,800 and 67,100 GWH generated. However, the simulated minimum occurs at approximately 35,000 GWh.
*** Alternative wage definition does not differentiate between full- and part-time employees.

ferences in management capabilities; capacity utilization; types of fuels used; reliance on nuclear, hydro, gas turbine and purchased power; regional differences in energy and peak demand; holding company attributes; and construction types and costs. They estimate the cost curves with 1971 data on 74 electric utilities and report the implied scale effects for each of the cost categories.

Their disaggregated results corroborate the other studies in Table 3 that focus on total costs. In particular, they find increasing returns to scale for smaller firms; flat long-run average costs for broad ranges of scale; and diseconomies of scale for larger firm sizes. While Christensen and Greene[46] find minimum efficient scale to be 19,800 GWH or about 4,100 MW in 1970, these authors estimate MES for production operating costs

46. Christensen & Greene, *supra* note 33.

occurs at 1,600 MW. Other selected measures of MES are 1,600 MW for total operating costs; 2,600 MW for distribution operating costs; 3,100 MW for fixed investment in generation; and 2,500 MW for administrative and general operating expenses.

Karlson, in his article *Multiple-Output Production and Pricing in Electric Utilities*,[47] takes as his point of departure Joskow and Schmalensee's[48] observation that the cost of an optimally configured utility depends in complex ways on the distribution of demand over time and space.[49] Because this demand distribution is determined by the mix of residential, commercial, industrial and wholesale customers, the author exploits a multi-product function that explicitly accounts for customer diversity by including electricity sales to the four customer groups. The specification allows for the estimation of scale effects and scope economies across customer classes.

Karlson estimates his model with a sample of 28 privately-owned, predominantly coal-fired electric utilities in 1978. He finds that scale economies continue to exist up to his largest sample firm, which sold 33,400 GWH. He also finds that scope effects across customer classes are statistically important.[50]

John Mayo, in an article entitled *Multiproduct Monoply, Regulation, and Firm Costs*,[51] analyzes the costs of combination utilities. He specifies a cost function in electricity and gas sales in order to assess the presence of scope economies across the two fuels. He estimates his model using 1979 data for 131 electric firms, 20 gas utilities and 49 combination utilities. His estimates suggest that MES for combination utilities ranges from 4,300-9,400 GWH for electricity sold or delivered.[52] He also estimates electricity-specific MES to be 34,000 GWH sold. He finds scope economies for small firms. However, the scope economies are exhausted for combination utilities with output levels in the range of 2,500-5,000 GWH of electricity and 50,000-75,000 MMCF of gas.

47. Stephen H. Karlson, *Multiple-Output Production and Pricing in Electric Utilities*, 53 S. ECON. J. 73 (1986).

48. JOSKOW & SCHMALENSEE, *supra* note 6.

49. Statistical cost analyses of generation costs *alone*, in essence, assume that all GWH generated are homogeneous. When analyzing the vertically integrated firm, however, this may not be a good assumption. For the integrated firm, see JOSKOW & SCHMALENSEE, *supra* note 6, at 54-55, where the authors correctly observe that GWH are not homogeneous at the transmission and distribution level, stating that:

> [T]reating diverse power systems as single-product firms operating under identical conditions is likely to produce error. The cost of an optimally designed power system depends in complex ways on the distribution of demand over time and space. No two power systems produce the same mix of products, and product mix differences affect the magnitude and form of optimal investments in transmission and distribution.

50. *See* Karlson, *supra* note 47.

51. John W. Mayo, *Multiproduct Monopoly, Regulation, and Firm Costs*, 51 S. ECON. J. 208 (1984).

52. This range summarizes results along a ray average cost curve.

Mark Roberts, in *Economies of Density and Size in the Production and Delivery of Electric Power*,[53] uses a cost model of electric power production and delivery to examine the magnitude of density economies in the transmission and distribution of electricity. He introduces three measures of density and scale economies: the effects of increased demand by existing customers; the effects of demand by new customers within the existing service territory; and the effects of expanding the service territory. The model is estimated with a cross section of 65 privately-owned, vertically-integrated electric utilities in 1978.

His results suggest that the most important source of declining average cost is an increase in the quantity of output consumed per customer. Holding everything else constant, increasing customer density has only a slight efficiency effect. Increasing the size of the service territory, holding everything else constant, is efficiency neutral. Specifically, he finds that a 1% rise in output, holding both the number of customers and service area constant, leads to a .82% increase in total cost. A 1% rise in density (both output and number of customers) leads to a .98% increase in total cost. A 1% rise in the geographic size of the firm's service territory leads, on average, to a 1% increase in total cost.[54] The results imply that utility mergers which *only* expand the customer base and/or the service territory may be efficiency-neutral.

Merrile Sing addresses scope and scale economies in gas and electric utilities by examining whether combination utilities or single fuel utilities provide services more efficiently.[55] For combination utilities, economies of scope are argued to arise from joint and common inputs such as meter reading, billing, accounting and engineering services. They are also argued to arise from any technological advantage that may occur in generating electricity given internal access to gas supplies. Sing estimates a cost function with data for a 1981 cross-section of 108 utilities, including 43 combination utilities, 31 gas utilities and 34 electric utilities. Economies of scope are found for large utilities, while diseconomies of scope occur in small utilities. Furthermore, diseconomies of scope exist for the average combination utility, (*e.g.*, one producing 11,200 GWH of electricity and 78,000 MMCF of gas).

Sing does not specifically calculate a range of electricity-specific returns to scale or MES. However, he indicates that his average combination utility has electricity-specific returns to scale of 1.66, which is well above 1.0. Hence, the electricity-specific MES is at least as large as the average utility, which sells 11,242 GWH.

53. Mark J. Roberts, *Economies of Density and Size in the Production and Delivery of Electric Power*, 62 LAND ECON. 378 (1986).

54. *Id.*

55. *See* Merrile Sing, *Are Combination Gas and Electric Utilities Multiproduct Natural Monopolies?*, 69 REV. ECON. & STAT. 392 (1987).

Rodney Stevenson compares the generation of electricity of single-fuel utilities with that of combination utilities.[56] If combination utilities experience economies of scope, they should demonstrate lower generation costs than single-fuel utilities, holding everything else constant. If, however, the combination utilities experience less competition because they have internalized and eliminated interfuel competition, they will demonstrate higher costs if the resulting loss of competitive pressure overwhelms the scope effects. To test this hypothesis, Stevenson uses a sample of 79 utilities, 25 of which are combination utilities. Focusing on electricity generation costs, he extends cost formulations to include capacity utilization and a dummy variable indicating whether the utility is a combination utility. He finds that combination utilities do indeed generate electricity inefficiently. He concludes that new entry and increased interfirm rivalry, where the interfirm rivalry *is interfuel*, may be a very useful regulatory tool for promoting improved utility performance.

D. *Summary of Statistical Insights Gained*

The studies in Table 3 use state-of-the-art econometric specifications.[57] The techniques are applied to a diverse number of data sets from 1970, 1971, 1970-1972, 1978, 1979, 1981 and 1987. Some of the data sets include a small number of utilities. For example, in order to focus upon firms with similar technologies, similar market conditions and similar regulatory environments, Karlson[58] restricts his data set to only 28 coal-fired utilities. Other analysts attempt to characterize production and costs for a much more diverse set of electric utilities (100 - 180 firms), or for a mix of gas, electric and combination utilities.

The studies identify "average" tendencies. For example, they indicate how the scale of utility operations affects cost for the "average" firm, where the average reflects the sample of utilities included in the specific study. Individual firms may differ from the "average"; however, the "average" tendencies provide a powerful first approximation of the cost effects of particular efficiencies. Furthermore, the fact that a diversity of data sets, time periods and analytic foci lead to similar "average" tendencies is useful for robustness tests. If consistently robust patterns are evident, the fact that they are found in the face of such diversity will give us grounds for confidence in our conclusions.

The first conclusion that leaps from Table 3 concerns scale effects. All of the studies find significant increasing returns to scale for smaller utilities and, *at best*, constant returns to scale for large utilities. No study suggests that minimum efficient firm scale for electricity generation alone (point A) in Figure 1 is smaller than 7,700 GWH or 1,600 MW (assuming a 55% load factor). The Mayo study finds MES for electricity of combined utilities to

56. *See* Rodney Stevenson, *X-Inefficiency and Interfirm Rivalry: Evidence from the Electric Utility Industry*, 58 LAND ECON. 52 (1982).

57. In particular, translog, generalized translog, Box-Cox, and linear quadratic cost functions were employed. Likewise, the appropriate econometric techniques were employed.

58. Karlson, *supra* note 49.

be in the range of 4,300-9,400 GWH sold. However, one of Mayo's *electricity-specific* estimates of MES is 34,000 GWH sold. The conclusions of the other statistical cost analyses are surprisingly robust. Minimum efficient firm size (MES) for the bulk of the studies is in the range of 2,000-4,000 MW of capacity; 9,000 - 30,000 GWH of net generation; and 10,000 - 35,000 of GWH of sales. This conclusion is *robust* to the specification of the cost functions.[59] This conclusion is *robust* to analytic focus (either generation costs or labor costs alone or total costs). This conclusion is *robust* to the specification of cost function as single product or multi-product.[60]

Indeed, we can be even more precise. If we take all of the estimates of MES in terms of sales, we have 16 estimates with an average MES of 22,180 GWH. An approximate 95% confidence interval for this MES estimate is (12,480 GWH < MES < 39,400 GWH).[61] Furthermore, if we translate the MES estimates in terms of generation into sales, we obtain an average MES of 19,300 GWH using 23 estimates. A 95% confidence interval for this estimate is (12,000 < MES < 31,200 GWH).[62]

The evidence concerning scope economies is more mixed. Two studies in Table 3 find scope economies in smaller firms. The economies alternatively arise from the diversity of electricity customer classes[63] and the

59. It holds for *all* the cost functions: the translog: the translog adjusted for regulatory biases: the *ad hoc* functions; the linear quadratic; and the Box-Cox.

60. *See* Karlson, *supra* note 47 (specifying alternative products by electricity customer classes); *see also* Mayo, *supra* note 40, and Sing, *supra* note 55 (finding corroborative electricity specific scale effects for cost functions defined over gas and electric customers).

61. This is calculated as follows: For a given regression, the implied MES is derived from the coefficients of the scale variables. For example, in the semi-log and log-log regressions, we have Cost = constant + a * ln(GWH) + b * (ln(GWH))^2 and $\hat{Z} = \ln \hat{MES} = (-\hat{a})/(2*\hat{b})$. Because the regression coefficients are asymptotically normal, $\hat{Z}$ is asymptotically normal with $V(\hat{Z})$ estimated as a first-order Taylor approximation in the variances and covariance of the regression coefficients $\hat{a}$ and $\hat{b}$. Specifically,

$$V(\hat{Z}) = 1/4\ [(1/\hat{b}^2)\ \sigma^2_a + (\hat{a}^2/\hat{b}^4)\ \sigma^2_b - 2\ (\hat{a}/\hat{b}^3)\ \sigma_{ab}]$$

For the first semi-log estimate of Z in Table 3, $V(\hat{Z}) = V(\ln \hat{MES}) = .6875$.

Working with the natural logarithm of each of the MES estimates in Table 3, we have that the average $\hat{Z}$ = average ln $\hat{MES}$ = 16.9145. The variance of this estimate is determined by the sum of the variances + covariances of the individual estimates of ln MES. Because some of the MES estimates are derived with data from different years and because I lack information on the covariances of the MES estimates using data from the same year, I am forced to assume that all of the covariances are zero. Furthermore, because I have no information on the estimated variance of the MES estimates from other authors, I assume that V(ln MES) is constant for all estimates and is equal to *twice* my estimate of $V(\hat{Z})$ = 2*.6875 = 1.375. I double my estimated variance in an attempt to be conservative.

Given these assumptions, prob $[16.9145 - \sqrt{(1.375/16)}*1.96 < \ln MES < 16.9145 + \sqrt{(1.375/16)}*1.96]$ = 95%. Details are available from the author on request.

62. The average utility in the 1987 cross-section sold 5.9% more electricity than it generated. I therefore use 1.059 to increase the estimates of MES in terms of GWH generated and thereby approximate MES in terms of sales.

Again working with $\hat{Z} = \ln \hat{MES}$, the average ln $\hat{MES}$ = 16.7759 for the 23 estimates in Table 3. I make the same assumption regarding the covariances of the estimates of ln MES. I also assume that $V(\hat{Z}) = 2 * .6875$ for all $\hat{Z}$, as above. As a result, Prob $[16.7759 - 1.96 * \sqrt{(1.375/23)} < \ln MES < 16.7759 + 1.96 * \sqrt{(1.375/23)}]$ = 95%.

63. *See* Karlson, *supra* note 47.

diversity of fuels.[64] However, Sing's results[65] contradict those of Mayo:[66] he finds that scope economies in combination utilities exist for larger firms and diseconomies exist for smaller firms. Both Mayo and Sing find that the scope economies arising in combined-fuel utilities disappear for the average sized firm. Furthermore, Stevenson presents evidence that scope effects in dual-fuel utilities are uniformly negative.[67] In particular, he compares the electricity generation cost of dual-fuel utilities with those of electric utilities and finds the dual-fuel firms' costs to be higher. He concludes that, everything else equal, the potential production efficiencies arising with combining electric and gas utilities are overwhelmed by the loss in competition between the separate and independent gas and electric utilities.[68]

To summarize the scope effects, the empirical findings support the existence of scope economies among sales to alternative classes of electricity customers. These effects were predicted in the discussion in Section II.A regarding the operational efficiencies arising from the integration of geographically dispersed loads with different peaking characteristics. The case for scope economies arising across energy sources in combination utilities is much less persuasive. The evidence, which itself is somewhat contradictory, predominantly supports the contention of scope diseconomies. Certainly, there is little evidence supporting the existence of scope economies in firms larger than the average combination utility.

Finally, the single study that focuses upon customer density and the size of the service territory concludes that density and the size of the service territory are essentially efficiency neutral.

IV. Summary and Conclusions: The Lessons of Statistical Cost Analysis for Utility Merger Policy

A. *Conclusions for Traditional Mergers of Regulated Utilities*

The FERC and state regulatory commissions continue to evaluate mergers of vertically integrated electric utilities using a variety of criteria, only one of which is the efficiencies induced by the merger.[69] What can these regulators (and the courts) learn from the evidence assembled here concerning the efficiencies induced by merger?

The discussion in Section II identifies efficiencies made possible by the vertical structure of the electric utility industry. Based upon that discussion, regulators should scrutinize the efficiency claims of merger applicants in

64. *See* Mayo, *supra* note 51.
65. Sing, *supra* note 55.
66. Mayo, *supra* note 51.
67. Stevenson, *supra* note 56.
68. *See* Sing, *supra* note 55 (explaining his results and citing Alfred Kahn as holding and articulating this belief in A. KAHN, THE ECONOMICS OF REGULATION: PRINCIPLES AND INSTITUTIONS (1971).
69. The differing legal standards and evaluation criteria of the FERC and state commissions are introduced briefly *supra* note 2. The FERC and state commissions generally give different weight to various criteria.

order to assess whether forecasted merger savings are predicted to result from vertical or horizontal consolidation. Efficiency gains from vertical consolidation are more plausible and should be given more weight. Section II indicates the appropriate type of scrutiny by examining recent utility mergers and discussing the technological credibility of the *ex ante* efficiency studies submitted in support of each merger.

The discussion in Section III is critical for regulators and the courts. The Section begins by questioning the general reliability of *ex ante* efficiency studies supporting mergers and cites evidence suggesting that *ex ante* studies are inaccurate and unreliable 60-80% of the time. The Section briefly suggests the reasons for their inaccuracy and argues that statistical cost analysis provides important information to assist in assessing the credibility of *ex ante* predictions. Section III concludes by describing how statistical cost analysis can be used to identify and measure possible efficiency gains arising through merger, and thereby confirm or contradict *ex ante* predictions.

The preponderance of the econometric evidence reported in Section III indicates that minimum efficient size for a vertically integrated firm falls in the range of 9,000-30,000 GWH of generation and 10,000-35,000 GWH of sales. Indeed, the 10,000-35,000 GWH range seems to be a reasonable approximation of a 95% confidence interval for the minimum efficient size of a vertically integrated electric utility. This conclusion is robust to a wide variety of time periods and sample utilities reflected in the alternative data bases used. The statistical cost analyses also indicate that combined-fuel scope efficiencies, if they exist at all, are exhausted fairly quickly, and that density economies are neutral.

This statistical cost evidence is useful for evaluating mergers in the following ways. First, if a particular set of merger candidates and the merged entity are all smaller than 10,000 GWH, the merger shall most probably generate the efficiency gains predicted in an *ex ante* analysis. The reason is that there exist very real scale economies to be exploited in this size range. This is true for scale effects up to the mean MES of 19,000-22,000 GWH. In this size range, it is also less likely that the transitional costs of integrating the two (or several) separate entities have been underestimated. This will be particularly true if the merger is a merger of equals. At this scale, there is little reason to worry about empire building on the part of the merging firms. Managerial control loss is less likely and conflicts in corporate cultures are more easily identified and averted. *Ex ante* efficiency studies identifying efficiency gains in these cases are presumptively accurate. Specific operational evidence indicating inefficiencies should be required to refute efficiency claims in these cases. If there is little possibility of anticompetitive conduct by the merged entity,[70] the merger should be uncontested and even encouraged. An example of a merger of this type is the union of Eastern Utility Associates with Unitil and Fitchburg Gas and Electric. Because the merging firm and the combined entity were smaller

70. Which is probable, given the size of the utilities merging.

than MES, the predicted efficiency gains of 1.8 - 2.8% of annual operating revenues were credible. Even if the predicted savings (relative to annual operating revenues) are small (*e.g.*, less than 1%), the predictions are more credible for operating companies and merged entities below MES.

To the extent that the merger candidates and the merged entity fall along the horizontal part of the cost curve (between points A and B in Figure 1), the merger will most probably be efficiency neutral. The existing evidence suggests that the cost curve becomes horizontal at approximately 20,000 GWH and remains horizontal until at least 45,000-50,000 GWH. The merger-induced efficiencies predicted in this size range should be scrutinized more carefully because, "*on average*," increasing the size of these firms offers little in the way of efficiency gains. *Ex ante* efficiency studies that claim substantial merger savings in this range are not credible; they are most probably overly optimistic. Furthermore, the *ex ante* studies have most probably underestimated the costs of integrating the constituent firms. Problems of conflicting corporate cultures, managerial control loss, and loss of key personnel are more likely to arise in mergers of this size. Likewise, mergers of this size are more likely to be stimulated by empire-building. Because efficiency gains from size are neutral for firms in this range while merger-induced integration costs have probably been underestimated, mergers of firms in this size range will probably fail to achieve the predicted efficiency gains.[71] As a result, these mergers will more probably than not fail standard social benefits tests; that is, they will increase the costs of providing electricity to the combined service territories. Clearly, the FERC and state commissions will weigh these efficiency effects with a variety of other factors. However, the statistical costs analysis suggests that, based solely upon efficiency grounds, there is no compelling reason to permit the merger *unless* very careful and very detailed production cost simulation models corroborate the *ex ante* predictions of merger savings.[72]

Finally, if one of the merger candidates and the merged entity fall to the right of the horizontal portion of the estimated cost curves (beyond point B in Figure 2), the merger should be discouraged on efficiency grounds,[73] absent very persuasive evidence to the contrary. A reasonable estimate of point B is 50,000-60,000 GWH of sales. The reason for discouraging these mergers on efficiency grounds is that all of the problems identified for firms on the horizontal portion of the cost curve become more severe beyond point B. Favorable *ex ante* efficiency studies are almost always not credible beyond point B. These mergers are usually characterized by a large utility acquiring a smaller one. Problems of conflicting cor-

71. If the pattern of success and failure is similar to the broad cross-section of industries examined in the literature *supra* note 24, these mergers will fail more often than not.

72. Put differently, regulators should adopt a rebuttable presumption of merger-induced inefficiencies for merger applicants in this size range, irregardless of the effect of the merger on competition. Of course, both factors must be weighed in the final determination.

73. *See* Hartman, *supra* notes 24 and 38. It is likely that mergers of utilities of this size should be discouraged on other grounds as well. For example, it is much more likely that such mergers will tend to harm competition, although that determination must be made independently. Incidentally, the SCE/SDG&E merger fell in this size range.

porate cultures and loss of key personnel from the smaller firm can be quite typical in these cases. The empire-building motive is frequently operative in these cases. Any proposed advantage of these mergers can probably be better effectuated through contract rather than merger.

The evidence regarding scope effects suggests that efficiency gains in electric operations will be more likely when the customer mixes of the merging firms are more diverse. However, expanding the mix of energy sources (combining gas and electricity utilities) through merger should be discouraged. Scope efficiencies across fuels may exist for very small firms and may therefore work in the same direction as scale effects. However, even this interpretation of the evidence must be taken as suggestive only. Indeed, the evidence is such that where combination firms are merging, serious consideration should be given to the divestiture of the gas operations from the electricity operations.

The single study that addresses density economies suggests that mergers will be efficiency neutral if their sole effect is to increase the customer base (density) within the existing service territory and/or increase the size of the service territory. Customer density will increase with merger only if the service territories of the merging firms intersect. This is possible if fringe area competition exists. However, there is little evidence of such fringe area competition.[74] Furthermore, if such competition did exist, there are apparently no efficiency gains (or losses) that result from eliminating the competition through merger. Because these conclusions are based upon a single study, it would be useful to test whether one can replicate the results with other data bases.

B. *Conclusions for Merger Policy in the Restructured World*

The discussion in Section II indicates that significant efficiencies will not be gained by consolidating generation facilities (Gencos) in the restructured world. Minimum efficient scale has continued to decline, a fact confirmed by both engineering and statistical cost analyses. Mergers of Gencos will therefore seldom produce operational efficiencies,[75] and any *ex ante* prediction of merger-induced efficiencies will not be credible except perhaps for the smallest Gencos. Because such predicted efficiencies would normally be weighed with (or against) any predicted anticompetitive effects,[76] the fact that merger-induced efficiency gains are negligible should

74. *See* JOSKOW & SCHMALENSEE, supra note 6, ch. 2.

75. If predicted merger-induced operational efficiencies are real, it is most likely they are due to existing inefficiencies that can be eliminated without merger.

76. Section 7 of the Clayton Act, 15 U.S.C. § 18 (1994), prohibits mergers whose effects are substantially likely to lessen competition in the relevant antitrust markets. However, the DOJ and FTC may allow for the rebuttal of a presumption of diminished competition with a finding of merger-induced efficiency gains (among other things). The FERC similarly examines a merger's impact upon competition as one of its six criteria of evaluation and weighs it with the merger-induced efficiencies (among other things).

Parenthetically, it has been argued that application of the Section 7 standard to most historical utility mergers would not have altered the FERC's recommendations. *See, e.g., Interview with Richard Gilbert*, INSIDE FERC, Dec. 11, 1995, at 9.

stimulate a more single minded scrutiny of the effects of the merger on competition.[77]

The measures of MES estimated in Section III are for vertically integrated firms, and the accompanying discussion indicates that any efficiencies that remain to be exploited through merger will arise from vertical coordination. In a restructured world, these efficiencies will need to be exploited over a transmission system, the independent "functionally unbundled" operation of which will be regulated.[78] These efficiencies will need to be exploited by coordination and/or consolidation of aggregators of Gencos and aggregators of local distribution companies (LDCs)/wholesale customers/large retail customers.

The institutional and operational design of the transmission system will be, therefore, crucial to the functioning of electric power markets in general and the efficiencies to be gained from vertical coordination or consolidation. The more efficient the regional transmission system, the more dispersed and diverse will be the Gencos that can sell power into the regional market and the more diverse and dispersed will be the customers demanding that power and/or capacity. This greater dispersion and diversity will increase the potential for efficient vertical coordination and will limit market power of any single participant by increasing the number of geographically dispersed competitors.[79]

A fundamental component of the restructured transmission system will be the operating arrangements of the independent system operator (ISO). Two polar extremes have been introduced into the policy debate—a system of pure Mandatory Pooling and a system of pure Bilateral Trans-

77. The concern for the effects of Genco merger on competition should be heightened by the experience in the United Kingdom. For example, David Newbury, *supra* note 21, examines the structure, conduct and performance of the English bulk electricity market since restructuring. He points out that fossil generating facilities were consolidated, for the most part, into *only two* generating companies, PowerGen and National Power, and that these two Gencos dominate supply. Based upon structural grounds, he concludes that "the two fossil generators would be able to sustain a non-collusive equilibrium in which prices were well above operating costs. *See* Newbury, *supra* note 21, at 46. It is therefore not surprising that over the period since restructuring, he finds that open access increases production efficiency but that none of the efficiencies are passed onto consumers. He states that "the sharp increase in the gross profit per kWh of the successor companies [the merged companies] . . . [are] more than offsetting the considerable fall in labor costs resulting from the massive increase in labor productivity, and leading to *higher* prices despite the fall in fuel costs." Newbury, *supra* note 21, at 59.

Newbury, *supra* note 21, and Green & Newbury, *supra* note 21, further suggesting that a structure based on five Gencos rather than two would be workably competitive. *See also* Hartman & Tabors, *supra* note 21.

78. I do not explore all the varied proposals for open access here. Under all proposed alternatives, functional unbundling will be implemented across generation, transmission and distribution. This functional unbundling may involve corporate divestiture of assets across all three levels; however, complete divestiture is not required. Arms-length transactions are required, however, they may be effectuated. Most importantly, the independent system operator (ISO) should have no identifiable financial interest in the sources of generation or in wholesale or retail distribution. For more detail, see Hartman & Tabors, *supra* note 21.

79. By increasing the efficiency of the regional transmission system, I mean reducing transmission constraints and losses. Both will contribute to increasing the size of the antitrust market defined by the standard criterion of a 5% price rise for a hypothetical monopolist.

actions. Briefly, under a pure Mandatory Pooling System, *all* generators would nominate, sell and dispatch their power to the ISO, which would act as a regulated monopsonist. Acting as a regulated monopolist, the ISO would turn around and sell power to all consumers, including industrial customers and LDCs. Alternatively, under a system of pure Bilateral Transactions, the ISO simply operates the grid and implements, through non-discriminatory access, power transactions negotiated independently by other parties.[80]

The operating arrangements of the transmission system will determine how the exploitation of vertical scale and scope economies will be accomplished. Under pure Mandatory Pooling, the coordination economies will be exploited by the single pooling agent, the ISO. Under pure Bilateral Transactions, these economies will be exploited by any set of transactors *and* a variety of aggregators. In either case, given the estimates of Section III, increased scale and scope economies will be possible until the size of the grid reaches approximately 20,000 GWH of sales. Furthermore, there is some evidence that grid-wide scale and scope economies may be exhausted at substantially smaller grid sizes.[81]

What are the implications for merger policy? Under a system that approximates pure Mandatory Pooling, all vertical efficiencies will fall under the jurisdiction of the single regulated ISO. In this case, the ISO as aggregator should be allowed to become as large as possible, in order to most effectively exploit the available scale and scope economies,[82] and it should be structured with the financial incentives to exploit these economies. Because LDCs will remain regulated and there will be little wholesale wheeling,[83] there will be no real efficiency reasons to allow LDCs to merge with Gencos.[84] Finally, the statistical cost analysis suggests that

80. In reality, most proposed operating arrangements are hybrids of these two basic arrangements, and unfortunately many of the hybrid arrangements are called "Mandatory Pooling" or "Bilateral Transactions," which only confuses comparative discussions.

Hartman & Tabors, *supra* note 21, have scrupulously defined and explored these two operating arrangements as "straw-person" polar extremes, in order to avoid the confusion that arises with attributing the characteristics of a hybrid system to one of the two *basic* operating arrangements. For the discussion here, I continue to use these straw-person definitions. Hence, readers should not assume that by Mandatory Pooling I am thinking specifically of the Fessler Plan, PROPOSAL II, *supra* note 21, or the U.K. plan. Likewise, I am not thinking specifically of the Knight Plan, PROPOSAL I (ALTERNATIVE), *supra* note 21, or the Norway Plan, *supra* note 21, when I refer to Bilateral Transactions.

81. Recall that Hartman, *supra* note 41, finds that utilities that are commonly-owned through a power pool and centrally dispatched reveal MES of 12,000 GWH of sales. Furthermore, both estimates may be too large since they are based upon cost data from a time period when X-inefficiency and cost-based regulation were in effect. It is likely that increased competition will reduce costs and MES further.

82. It is possible that the ISO may be smaller than system MES for small isolated regional grids. However, given the increased interconnectedness of the national grid, this becomes increasingly unlikely.

83. Remember, under my definition of pure Mandatory Pooling, wholesale and retail wheeling are not permitted.

84. Given that the ISO and the LDCs will continue to be regulated, one might argue that merger standards dealing with competitiveness may need to be less rigorous. However, the experience of the

there are no efficiencies to be gained by allowing the ISO to integrate with gas transmission/supply in the relevant regions, due to potentially decreased interfuel competition.

Under a system that approximates pure Bilateral Transactions, all vertical efficiencies will be exploited by competitive (unregulated) aggregators.[85] The statistical cost analysis suggests that there will be real scale and scope economies with the vertical merger of demand and supply aggregators until the merged entity reaches 12,000-20,000 GWH of energy sold. If such mergers do not harm competition they should be allowed. For grids (Regional Transmission Areas — RTAs) that are both antitrust markets and sufficiently large, competition among multiple aggregators of MES will stimulate productive efficiency and allocative efficiency.[86]

A more distinct tension between efficiency and competitiveness will arise with smaller RTAs. For grids that are both antitrust markets and smaller than MES, a single aggregator of supply and demand would be most efficient on operational grounds, everything else equal. Indeed, a single aggregator will be most efficient for any grid less than twice MES.[87] However, the statistical cost analysis also suggests that competition may be more important in lowering costs than are scale and scope economies. The fact that economies are technologically possible by a merger that increases scale and scope toward MES may be irrelevant if loss of competition results.[88] If the RTA is not sufficiently large to support a workably competitive number of aggregators, it is most likely that the efficiency gains predicted *ex ante* may be real but will be lost to the consumers without competition. A logical compromise for such smaller RTAs would be some lower bound on the number of competitors allowed in the market or some upper bound limitation on the market share allowed for any single vertically integrated aggregator.[89]

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restructured industry in the U.K. suggests that competitiveness standards (both horizontal and vertical) should be aggressively enforced under a system that looks like pure Mandatory Pooling, as defined in the text.

85. For expositional simplicity, I have explored conclusions for the two *basic* arrangements only. Under a hybrid system (such as that proposed in PROPOSAL I, *supra* note 21), the conclusions must be appropriately modified to the specific facts of the hybrid.

86. Extrapolating from Newbury, *supra* note 21, and Greene & Newbury, *supra* note 21, a rough rule of thumb would be at least five vertically integrated aggregators.

87. It is unlikely that there will be many grids that are antitrust markets and are this small.

88. Of course, these conclusions are drawn from statistical analyses of regulated utilities. There is no evidence that an unregulated monopolist would exploit returns to scale and scope to the same extent as a regulated one. However, the limited evidence for the U.K. suggests that even if an unregulated monopoly were more efficient than a regulated one, everything else equal, those efficiencies would be captured entirely by the monopolist.

89. Precedents for this approach are common. *See, e.g.*, Cable Communications Policy Act of 1984, Pub. L. No. 98-549, 98 Stat. 2779 (codified as amended at 47 U.S.C. § 521); and the Cable Television Consumer Protection and Competition Act of 1992, Pub. L. No. 102-385, 106 Stat. 1460 (codified as amended at 47 U.S.C. § 533). Further precedents are found in the recently proposed (yet still to be enacted) revisions of the telecommunications bill.