THE ECONOMIC EFFECTS OF FORCED GEOGRAPHIC INTEGRATION OF ELECTRIC UTILITY HOLDING COMPANIES

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The purpose of this study is to determine the effects of application of Section 11 (b) (1) of the Public Utility Holding Company Act of 1935 on costs of electric subsidiaries of affected holding companies. Since the geographic integration required by this section of the Act has now been largely completed, enough data are available to make a valid judgment possible.

The method followed is to make an exhaustive case study of all such holding companies and their subsidiaries. In order for this to be meaningful, it is first necessary to determine just what affects electric utilities' costs. Technical studies indicate that production costs are determined primarily by the size of interconnected and coordinated plant because of: 1) reduced fuel and labor costs per kilowatt-hour of output as turbine-generator size increases, and 2) reduced capital costs, due both to a decline in costs per kilowatt of capacity as turbine-generator size increases and a reduction in necessary (reserve) capacity as plant size increases. Firm (management and capital) costs appear to be influenced primarily by the size of the operating company. Holding company size appears to influence these costs, if at all, only in the (Federal Power Commission) account "administrative and general expense."

The case studies then follow.

A technique is devised to measure changes in administrative and general expenses of companies required to be divested by holding companies. The percentage this account is of gross electric operating revenue is calculated for every divested subsidiary for those years for which data are available, generally 1938-1950. These percentages are averaged for the years prior to separation, and the years following. The percentage change between these two averages is then found. This figure is compared with the comparable one for all electric utilities in the United States. While of little significance for any one company, loss of firm economies would be indicated by a general relative increase in this index for all divested subsidiaries, as compared with all companies. The data indicate that this did not happen. Of sixty-one divested companies which became independent, thirty-one show declines of more than the national average, eight show declines equal to the national average, and twenty-two show declines of less than the national average. In addition, the four divested companies for which data are available which were acquired by independents all show declines greater than the national average.

Thus, since the case studies show that only holding company size has been affected by the Act, losses of firm economies are not apparent. Increases in plant costs have

not resulted, since in only two cases were interconnected properties ordered separated from common control, and this did not affect operating relationships. Decreases in plant costs have resulted through isolated operating properties of holding companies being acquired by adjacent operating companies. The conclusion is that application of Section 11 (b) (1) has not increased costs of electric subsidiaries.

PREFACE

Ever since the enactment of the Public Utility Holding Company Act of 1935, there has been a continuing controversy on the effects of certain of the Act's provisions on the costs of electric utility operating companies. It appears that sufficient time has passed and enough data are now available to make it possible to determine what the effects actually have been. This thesis is the result of an attempt to do that.

The writer's interest in this general area was first aroused by Dean Carl Krieder of Goshen College. After World War II, Professor I. L. Sharfman's seminar in social control at the University of Michigan stimulated further development of the study. The suggestions and helpful criticisms of Professor Shorey Peterson resulted in the study reaching its present form. Professors Daniel Suits and Kenneth Boulding aided greatly in developing the analysis of firm costs. Professor Merwin Waterman's extensive knowledge of this area was placed at the disposal of the writer. The management of the Detroit Edison Company, particularly Mr. Howard P. Seelye, Manager of Engineering, gave great assistance by furnishing technical data and answering numerous technical questions.

All maps contained herein (with the exception of the first) are reproduced through the courtesy of the Securities and Exchange Commission.

TABLE OF CONTENTS

	Page
LIST OF TABLES	v
LIST OF MAPS	vii
LIST OF FIGURES	viii
Chapter	
I. THE PUBLIC UTILITY HOLDING COMPANY ACT OF 1935	1
Introduction	
Reasons for Passage of the Act	
Proposals for Legislation	
Integration Provisions of the Act	
II. THE EFFECTS OF SIZE ON COSTS OF ELECTRIC UTILITIES	19
Plant Size	
Firm Size	
III. EFFECTS OF DIVESTITURE ON COSTS--CASES OF CLAIMED ECONOMY LOSSES	40
Associated Gas and Electric Corporation	
Cities Service Company	
Electric Bond and Share Company	
American Gas and Electric Company	
American Power and Light Company, Electric Power and Light Company, National Power and Light Company	
Engineers Public Service Company	
Middle West Corporation	
North American Company	
IV. EFFECTS OF DIVESTITURE ON COSTS (CONTINUED)--CASES WHERE ECONOMY LOSSES WERE NOT CLAIMED	199
American Water Works and Electric Company	
Columbia Gas and Electric Company	
Commonwealth and Southern Corporation	

Chapter Page

IV. (Continued)

Community Power and Light Company
Ogden Corporation
Republic Service Corporation
Standard Gas and Electric Company
United Gas Improvement Company
United Light and Power Company
United Public Utilities Corporation

V. CONCLUSION 296

APPENDIX 313

BIBLIOGRAPHY 318

LIST OF TABLES

Table		Page
1.	Per Cent of Estimated Losses of Economies to Operating Revenue	52
2.	Divested Subsidiaries of Associated Gas and Electric Corporation	65
3.	Public Service Company of Colorado	95
4.	Tucson Gas, Electric Light and Power Company	96
5.	Divested Subsidiaries of Cities Service	97
6.	Divested Subsidiaries of American Gas and Electric Company: Atlantic City Electric Company, and Scranton Electric Company	120
7.	Retained Subsidiaries of American Gas and Electric Company	122
8.	Acquired Subsidiary of American Gas and Electric Company	123
9.	Divested Subsidiaries of Electric Bond and Share Subsidiaries	141
10.	Middle South Utilities	143
11.	Divested Subsidiaries of Engineers Public Service Company	154
12.	Economy Interchange of Energy in Middle West's Southwestern Group for one Month (in Thousands of kwh)	170
13.	Divested Subsidiaries of the Middle West Corporation	176
14.	Divested Subsidiaries of the North American Company	197
15.	Divested Subsidiaries of Columbia Gas and Electric Company	210

Table | Page

16. Divested Subsidiaries of the Commonwealth and Southern Corporation 232

17. Divested Subsidiaries of Community Power and Light Company 238

18. Divested Subsidiaries of the Ogden Corporation . 244

19. Divested Subsidiaries of Standard Gas and Electric Company 259

20. Divested Subsidiaries of United Gas Improvement Company 270

21. Divested Subsidiaries of United Light and Railways Company 287

22. Dakota Public Service and Montana-Dakota Utilities 294

23. Effect of Divestiture on Administrative and General Expense 306

24. All Class A and B Privately Owned Electric Utilities in the United States 317

LIST OF MAPS

	Page
Fields of Operations of Principal Power Groups, Located by Counties, 1932	4
Associated Gas and Electric Company System	42
General Public Utilities Corporation, Pennsylvania-New Jersey	55
Cities Service Power & Light Company System	68
Federal Light and Traction Company, Power Plants and Transmission Lines, with Proposed Interconnecting Transmission Lines, October 31, 1943	82
American Gas and Electric Company System	102
Electric Bond and Share Company System	127
Engineers Public Service Company System	145
The Middle West Corporation System	157
The North American Company System	179
Columbia Gas & Electric Corporation	203
The Commonwealth & Southern Corporation System	212
Ogden Corporation	240
Standard Gas and Electric Company System	253
The United Gas Improvement Company System	261
The United Light and Power Company System	272
Electric Service Area Map of Iowa and Surrounding Territory as of December 31, 1942	275
United Public Utilities Corporation	290

LIST OF FIGURES

Figure		Page
1.	Trend in Turbine-Generator, Boiler and Building Costs as Unit Size Increase	21
2.	Turbine Gross Heat Rate Trend with Steam Conditions Corresponding to Unit Size	23
3.	Fuel, Operating and Maintenance Cost Trend as Unit Size Increases	25

CHAPTER I

THE PUBLIC UTILITY HOLDING COMPANY ACT OF 1935

Introduction

The purpose of this study is to determine the effects of application of Section 11 (b) (1) of the Public Utility Holding Company Act on costs of electric subsidiaries of affected holding companies. This Act was passed by Congress in 1935 to correct what it considered to be abuses in the utility field. The Securities and Exchange Commission was given authority to regulate practically all matters concerning these systems, but the Act went further than regulation. Section 11 (b) (1)--generally referred to as the "death sentence"--required a utility holding company to limit operations of its subsidiaries to a single integrated system, thus requiring divestiture of many operating companies.[1]

Application was considerably delayed; at first because of legal questions, and later by the War. However, compliance is now substantially complete, and it appears that a valid judgment of the effects of this section can be reached.

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[1] There were possible exceptions to this. See below, p. 16.

The question of what the effects have been is more than an academic one. Critics of Section 11 (b) (1) have contended that it would result in increased costs and hence higher utility rates. One critic has gone so far as to say:

> The physical integration requirements contained in Section 11 (b) (1) was the strategic core of the adm. [sic] program to cure the patient of his ills by killing him.[1]

On the other hand, proponents of physical integration have taken exactly the opposite view:

> The remedy was suited to the patient..... Unified, technically related systems replaced systems of scattered, disconnected properties; economical organizations replaced conglomerate financial arrangements that served the interests of financiers.[2]

These statements illustrate the controversy over results which has gone on since the Act was passed.

This chapter contains a study of the events which led to the passage of the Act, the regulatory proposals made prior to its passage and relevant provisions of the Act. Chapter II is an investigation of the factors which determine costs of electric companies. Chapters III and IV contain case studies of all electric holding company systems which have been affected by the integration provisions of the Act. The final chapter draws general conclusions from these data.

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[1] Herbert F. Klingman, "Physical Integration of Public Utility Holding Companies since 1935" (Unpublished Ph.D. dissertation, Madison, 1949), p. 57.

[2] Emery Troxell, Economics of Public Utilities (New York, 1947), p. 172.

Reasons for Passage of the Act

Growth of holding companies in the utilities field had been a recent development. They were of little importance as late as World War I,[1] but by 1930, ten holding company systems controlled the production of about 75 per cent of the electrical power developed in the United States.[2] The map on the following page shows the extent of holding company systems in 1932.[3]

The reasons for this growth were in part technical. Due to improvements in generation and transmission of electric energy, it became economic to interconnect larger and larger areas and to operate them as a unit because of the resulting reduction in capital outlays and operating costs.[4] This was recognized at least as early as 1911,[5] and the advocacy of large systems, in order to reduce costs, became widespread

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[1] Jones estimates that the trend started in 1917. Herschel F. Jones, "Integration of Electric Utilities in the U. S." (Unpublished Ph.D. dissertation, Madison, 1942), p. 24.

[2] James C. Bonbright and Gardiner C. Means, The Holding Company (New York, 1932), pp. 91 ff.; Federal Trade Commission, Utility Corporations, 70 C., I s., Sen. doc. 92, Part 72-A, pp. 37 ff.

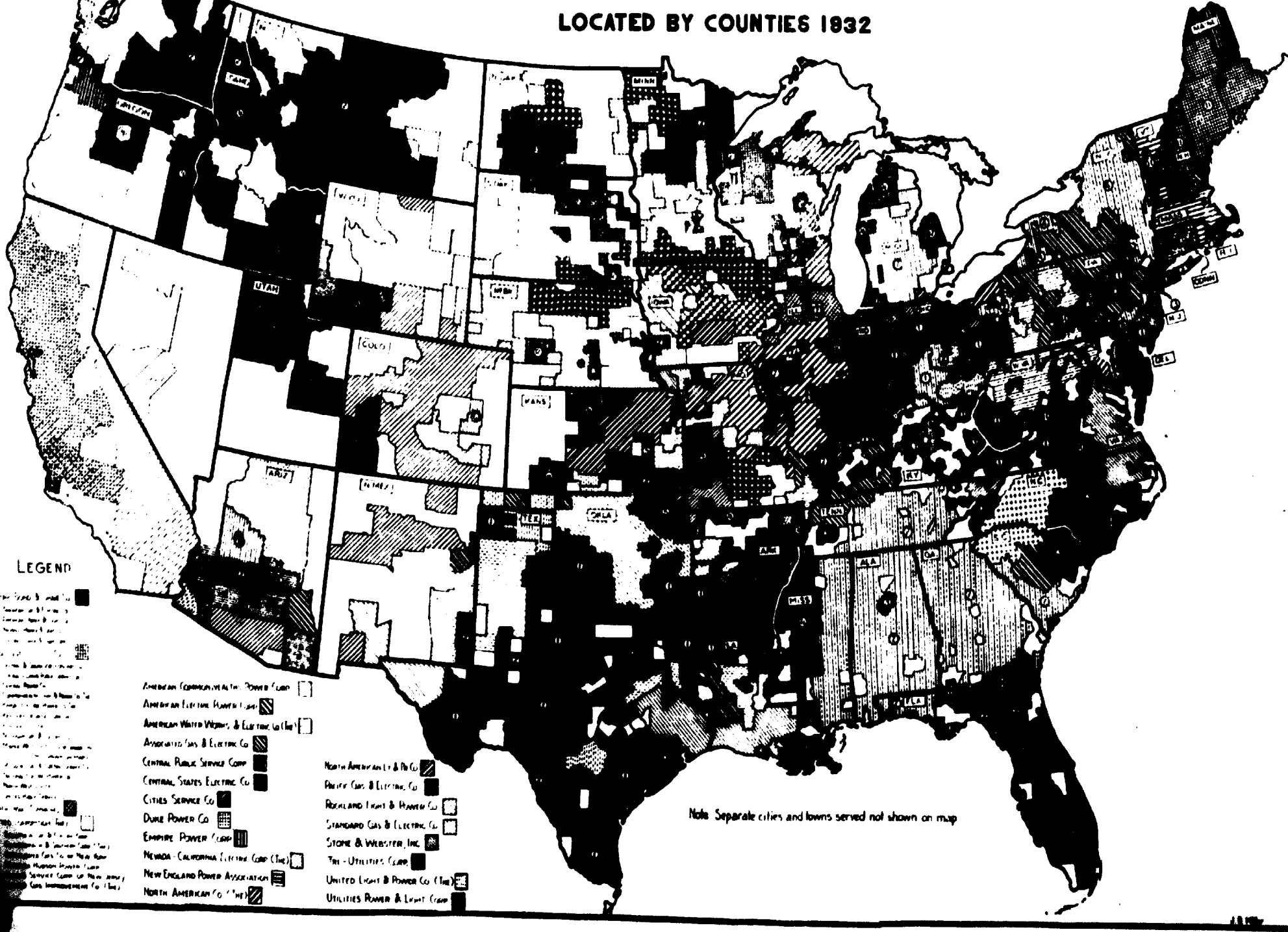
[3] Source: Federal Trade Commission, Utility Corporations, facing p. 56.

[4] See chap. ii for a discussion of these points.

[5] William Jackson, "Advantages of Unified Electric Systems Covering Large Territories," Transactions (New York: American Institute of Electrical Engineering), Vol. 30, Part 1 (1911), pp. 131 ff.

MAP IV. FIELDS OF OPERATIONS OF PRINCIPAL POWER GROUPS

LOCATED BY COUNTIES 1932



during the early 1920's.[1] These economies might be attained, at least in part, in various ways: smaller companies could be merged into one larger operating company; independents could interconnect and operate more or less as a unit through contractual arrangements (called power pools); the holding company device could be used.

The first method could not always be used because some states historically have required utilities to be domestic corporations. Also, bond indentures or charter provisions of operating companies, or actions of minority security holders might prevent merger. There is widespread interconnection between independents in this country, but it has not generally resulted in completely coordinated operation, since the bulk of these interconnections have been for emergencies and/or the wholesaling of energy.[2] Thus the benefits obtained by this method have been limited. The holding company device could solve these problems and make it possible to reduce costs. However, the map on page 4 shows that holding companies were not formed with these economies exclusively in mind, since, as a general rule, they did not confine themselves to a single operating area. Section 11 (b) (1) of the Act itself indicates this.

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[1] For a discussion of this point, see Jones, op. cit., pp. 16-23, and chap. iii.

[2] See chap. ii.

Other reasons for the growth of holding companies are to be found in the area of firm economies. It is possible that both capital and management costs can be reduced through operation of larger systems. A large utility system should have greater financial strength than a small local operating company, and a technical staff can be employed by a holding company to supply engineering, accounting, legal, financial and other assistance to its subsidiaries which, as independents, only the larger operating companies can afford.[1]

Just as in the case of production economies, firm economies could be obtained in other ways; for example, through independent service companies, but the growth of holding companies may be explained, in part, by firm economies.

That holding companies can make possible a reduction in costs, at least for the smaller operating subsidiaries, cannot be doubted, but the motive for doing it is not apparent. In the regulated utility field, reductions in costs should, in general, result in reductions in rates, since the primary function of regulation in these inherently monopolistic fields is to protect the consumer--that is, to allow only "normal" or "fair" or "necessary" business profits. However, if regulatory commissions are not vigilant, these gains will

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[1] See Federal Trade Commission, Utility Corporations, pp. 118-130; Bonbright and Means, op. cit., pp. 92-93; 20th Century Fund, Electric Power and Public Policy (New York, 1948), pp. 34, 344. These economies will be discussed in chap. ii.

accrue entirely to the system rather than to the consumer. In addition, since costs can in general be passed on to the consumer without fear of competitive underselling, there are numerous other possibilities for "insiders" to profit. Services or products may be sold to subsidiaries at high prices; poorly secured or low-interest-bearing upstream loans (from subsidiary to parent) can be arranged, and so can downstream loans (necessary or unnecessary) at high rates; insiders can hold well-paying positions in the system. Investment bankers might be interested in controlling holding companies because of the large amount of new security issues to be floated.

Property valuation write-ups, if they can be gotten into the rate base, will increase the dollar return. And, of course, the mere fact that fixed-income securities are in capital structures of the subsidiary operating companies means a multiplication of profit rates to the holding companies. In order to obtain this financial leverage, systems may force unduly large amounts of debt on subsidiaries. Pressure may be put on operating companies to continue to pay dividends, even if they come out of capital. Rate reductions may be discouraged.

While all these are possibilities, the fact that utilities have been regulated raises the question of whether they would be permitted. It appears that even with effective state regulation, holding companies have been beyond the reach



of such regulation.[1] Thus, although commissions might have authority to disallow unnecessary or excessive costs incurred by operating companies, the question of whether service charges, for example, are in fact excessive cannot be determined unless the holding company itself can be investigated. Furthermore, commissions have not been able to prevent such costs from being incurred. Consequently, failure of rates to cover costs would impair the capital of the utility, thus injuring its ability to provide service. Laxity on the part of the commissions could allow utilities to write up their rate bases, and overcapitalization of holding companies, over which the states have had no control, would tend to prevent rate reductions by subsidiaries.[2]

Whether because of lack of jurisdiction or poor regulation, there can be no doubt that the above practices occurred during the twenties. Criticisms of holding companies in this field became so widespread that the Senate, in 1928, ordered the Federal Trade Commission to make a full-scale investigation of the problem.[3] This investigation, perhaps the most thorough ever made of any American industry, extended over nine years.[4] It disclosed that at least some of the above

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[1] Bonbright and Means, op. cit., chap. 7.

[2] Ibid., pp. 163-174.

[3] S. Res. 83, 70th Cong., 1st Sess. (15 February 1928).

[4] Federal Trade Commission, Utility Corporations. The results of the investigation were published in 84 parts. Parts 21 through 82 are factual reports of cases of malpractices of holding companies. These are summarized in Part 72-A.

malpractices were indulged in by practically every utility holding company at one time or another during the twenties (although they appeared to be more prevalent in some systems than in others, as might be expected).

This investigation has been criticized (rightly, in some cases) on the grounds that: abuses inherent in any large business were condemned, abuses ten to thirty years old were listed as examples, one practice listed as an abuse was not, the useful functions provided by the holding companies were ignored.[1] But the long list of abuses uncovered by the Federal Trade Commission can hardly be explained by saying, as one writer has done, that the persistent demand for electrification of this country in the shortest possible time resulted in errors which a "more deliberate expansion policy might have prevented. The resultant mistakes were the result of haste."[2]

Other investigations were being made during this same period. In 1930, investigations made by public bodies in the states of Massachusetts and New York concluded that there was need for legislation to obtain some control over utility

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[1] See Arthur S. Dewing, Financial Policies of Corporations (2 vols.; 4th ed.; New York, 1942), pp. 1073 ff.; F. A. Finlayson, The Public Utility Holding Company under Federal Regulation ("University of Chicago Studies in Business Administration," Vol. 16, No. 3 [Chicago, 1946]), pp. 8 ff.

[2] Ernest R. Abrams, "Ten Years of the Public Utility Act of 1935," Public Utilities Fortnightly, 36 (1945), 616.

holding companies,[1] although neither state accomplished much in the way of new regulatory legislation.[2] Bonbright and Means' work, The Holding Company was published in 1932. The authors concluded from their investigation that "by means of the holding company, public utility operators have succeeded in drawing many of the teeth from the laws subjecting utilities properties to control by public service commissions."[3]

Public criticism became widespread following 1929. While probably only about one-third of utility holding companies went into receivership or bankruptcy,[4] the spectacular collapse of the systems of Insull, Foshay, Hopkinson, and others, which were evidently interpreted by both consumers and investors as evidences of reckless exploitation, seemed to make this field a public scapegoat. The collapses occurred even though private electric revenues in 1933 were only 11 per cent below the best known previous year.[5]

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[1] Commonwealth of Massachusetts, Report of the Special Committee on Control and Conduct of Public Utilities (Boston, 1930); New York State Commission on the Revisions of the Public Service Commissions Law, Reports and Hearings (Albany, 1930).

[2] Bonbright and Means, op. cit., pp. 217-220.

[3] Ibid., p. 339. This is usually considered to be the definitive work in this field.

[4] Klingman, op. cit., pp. 55-57.

[5] Louis M. Hacker and Benjamin B. Kendrick, The United States Since 1865 (New York, 1940), p. 721, quoting from The Economist, October 3, 1936.

This public clamor, in large part from those investors hurt by the holding company collapses, and the damage done to operating subsidiaries of bankrupt holding companies' systems, brought about an increase in many state commissions' regulatory powers,[1] but there was widespread demand for Federal action. The Democratic platform in 1932 contained a plank advocating the elimination of "unnecessary" holding company structures in the power field.[2] Following the elections, Federal legislation in this field became almost inevitable, but the question as to what form it should take resulted in a considerable amount of study.

Proposals for Legislation

A National Power Policy Committee, composed of the heads of all interested Federal departments and agencies, was set up to recommend legislation.[3] Its report recommended: elimination of all holding companies which did not serve a demonstrably useful and necessary purpose; restriction of all holding companies to the business of operating and owning securities of public utility property; creation of a commission to study existing systems with the purpose of simplifying them

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[1] Troxel, op. cit., pp. 72-73.

[2] Hacker and Kendrick, op. cit., p. 689.

[3] Among its members were Harold Ickes, William O. Douglas, and Robert Healy.

by eliminating unnecessary corporate complexities and operating companies which did not fit into an economic and geographical whole.[1]

An investigation made by Dr. Walter Splawn for the House of Representatives recommended that utility holding companies be eliminated, with the exception of those for temporary use for consolidation purposes, and the use of a first layer holding company in order to tie together, in harmony with state laws, operating companies in a limited region which might be divided by a state line or lines.[2]

The Federal Trade Commission had also made legislative recommendations on the basis of its investigation.[3] While the implication of the Federal Trade Commission seems to have been that the best and simplest solution would be to outlaw all holding companies, it recommended that one layer only of holding companies be allowed. "The necessary regulation would then be made easier, with only one party on each side of any transaction. The possible economies could still be achieved, and the possible diseconomies, while not made inherently impossible, would at least be amenable to discovery."

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[1] National Power Policy Committee, Report with Respect to the Treatment of Holding Companies, H.R., 74th Cong., 1st Sess., Doc. 137, March 12, 1935.

[2] Report on Power and Gas Holding and Operating Companies, 73d Cong., 2d Sess., H.R. 827, Part 2.

[3] Utility Corporations, Part 73-A, pp. 59-73.

It is evident that there was agreement within the Administration that regulation was not enough. Holding companies were to be eliminated in order that utility regulation could be effective. The only desirable exception was in the case of those which operated an integrated system, which could not be kept together as a unit without the use of a holding company.[1]

The Senate was evidently impressed by this point. The original Senate bill (S. 2796) required all utility holding companies to be eliminated within five years unless they could prove their necessity for efficient operation of a

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[1] President Roosevelt expressed it in these terms when he transmitted to Congress the report of the National Power Policy Committee: "The disappearance .... of those utility holding companies which cannot justify themselves as necessary for the functioning of utility operating companies is an objective which Congressional leaders I have consulted deem essential to a realistic and far-sighted treatment of the evils of public utility holding companies. For practical reasons we should offer a chance for survival of those holding companies which can prove to the Securities and Exchange Commission that their existence is necessary for the achievement of the public ends, which private utility companies are supposed to serve..... But where a holding company does not perform a demonstrably useful and necessary function in the operating industry, and is used simply as a means of financial control, it is idle to talk of the continuation of holding companies on the assumption that regulation can protect the public against them. Regulation has small chance of ultimate success against the kind of concentrated wealth and economic power which holding companies have shown the ability to acquire in the utility field. No governmental effort can be expected to carry out effective, continuous and intricate regulation of the kind of private empires within the Nation which the holding company device has proven capable of creating.

"Except where it is absolutely necessary to the continued functioning of a geographically integrated utility system, the utility holding company with its present powers must go." (pp. 1-5).

geographically and economically integrated system. In this case, one holding company layer would be permitted, if state laws did not prevent.

The House was evidently more impressed with the management and capital economies claimed to be obtainable through the use of holding companies. Although the regulatory aspects were substantially the same as in the Senate bill, the House version, as finally passed (H.R. 5423), shifted the burden of proof as far as eliminating holding companies was concerned. It required proof that a holding company system was detrimental before the scatteration of operating companies could be eliminated, and the same was true regarding new acquisitions by existing holding companies. The Senate refused the House's version, and the deadlock on attempts to compromise the wording was broken only after Administration pressure on the House.[1] Even though the compromise measure was closer to the original Senate version than to that of the House, it passed the Senate by only one vote. This was not because of the Senate's objection to the objectives of the compromise integration section, but because that body felt it to be too lenient.[2]

This final compromise version was evidently an attempt

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[1] See the letter written by President Roosevelt to Speaker of the House Rayburn: Franklin D. Roosevelt, Public Papers, ed. Rosenman, Vol. 4, pp. 328-329.

[2] See Jones, op. cit., chap. 7.

to reconcile these two opposing views by attempting to prevent undue loss of economies to subsidiaries of holding companies, while at the same time breaking down systems to a size amenable to regulation. It is clear that the intent of Congress was not to rationalize the electric power industry into operating systems of optimum size.[1]

Integration Provisions of the Act

The Public Utility Holding Company Act of 1935[2] gave the Securities and Exchange Commission power to regulate registered holding companies and their subsidiaries in regard to security transactions, acquisitions of securities and assets, the payment of dividends, solicitation of proxies, intrasystem loans and other intracompany transactions, service sales and construction contracts, and accounting practices. Section 11 (b) (1) required that:

> (b) It shall be the duty of the Commission, as soon as practicable after January 1, 1938:
> (1) To require by order, after notice and opportunity for hearing, that each registered holding company, and each subsidiary company thereof, shall take such action as the Commission shall find necessary to limit the operations of the holding-company system of which such company is a part to a single integrated public-utility system, and to such other

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[1] Ibid., p. 34.

[2] Public Act No. 333, 74th Cong., 1st Sess., Title I. Title II amended the Federal Water Power Act, and added a new Part II to that Act, which gave the Federal Power Commission certain regulatory powers over electric companies engaged in interstate transmission of energy.

businesses as are reasonably incidental, or economically necessary or appropriate to the operations of such integrated public-utility system: Provided, however, That the Commission shall permit a registered holding company to continue to control one or more additional integrated public-utility systems, if, after notice and opportunity for hearing, it finds that-

(A) Each of such additional systems cannot be operated as an independent system without the loss of substantial economies which can be secured by the retention of control by such holding company of such system;

(B) All of such additional systems are located in one State, or in adjoining States, or in a contiguous foreign country; and

(C) The continued combination of such systems under the control of such holding company is not so large (considering the state of the art and the area or region affected) as to impair the advantages of localized management, efficient operation, or the effectiveness of regulation.[1]

The Act defined an integrated electric utility system as follows (Section 2 (a) (29) (A)):

(29)"Integrated public-utility system" means-
(A) As applied to electric utility companies, a system consisting of one or more units of generating plants and/or transmission lines and/or distributing facilities, whose utility assets, whether owned by one or more electric utility companies, are physically interconnected or capable of physical interconnection and which under

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[1] Section 11 (b) (2) deals with the quite different problems of corporate structures and voting powers. Therein, systems are limited to no more than two layers of holding companies (the "great-grandfather" clause) and unnecessary complications and inequitable distribution of voting power must be eliminated.

To implement the requirements of Section 11 (b) (1), the Commission was given the power to control the acquisition of utilities systems under its jurisdiction. Approval can not be given "unless the Commission finds that such acquisition will serve the public interest by tending towards the economical and efficient development of an integrated public utility system." (Section 10 (c) (2)).

> normal conditions may be economically operated as a single interconnected and coordinated system confined in its operations to a single area or region, in one or more States, not so large as to impair (considering the state of the art and the area or region affected) the advantages of localized management, efficient operation, and the effectiveness of regulation.

Action to meet the requirements of Section 11 (b) (1) might be initiated either by a voluntary plan of the system under Section 11 (e) or by compulsory Commission order under Section 11 (d). Of course, in either case the requirements to be met are the same, and the Commission determines if they have been met. The most common procedure has been some combination of these.

The "ABC" provisions of Section 11 (b) (1) were the result of the compromise between the Senate and House. However, this compromise tended to obscure Congressional intent. An integrated system is defined as one that is capable of being economically operated as a unit, but clause (A) requires that only an integrated system may be retained as an additional system, and then only if it cannot be operated as an independent system without the loss of "substantial" economies. It may be that the definition of an integrated system refers to operating (plant) economies, while clause (A) refers to management (or other firm) economies, but this is not clear. Furthermore, the question of how large "substantial economies" are is left open.

Clause (B) is open to two interpretations; the "single area" interpretation, that both the principal and the additional

system (or systems) must be in the same state or states, or adjoining states, and the "two-area" interpretation, that the additional system or systems need not be adjacent to the principal system.

The Commission's interpretations of these provisions will be brought out in the case studies in Chapters III and IV. However, for the purpose of this study, the important thing is not the interpretation of the Act, but the economic effects of application of this section of it.

CHAPTER II

THE EFFECTS OF SIZE ON COSTS OF ELECTRIC UTILITIES

In order to determine what the effects of Commission decisions in specific cases have been, it is first necessary to see how size affects electric utilities' costs, since the integration requirements directly affect the size of holding company systems. In general, the size of two different units--the plant and the firm--are relevant. These will be taken up in turn.[1]

Plant Size

Plant is defined as the physical producing unit. In the electric industry, energy source and energy user must be physically connected and therefore electric plant is considered to be the combination of generation, transmission, and distribution facilities. It follows that interconnecting adjacent operating units will result in increasing the size of plant.

The larger the load, the larger the generating units may be. As size of generating units is increased, other

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[1] Much of the data herein was obtained from operating utility sources which prefer not to be cited.

things being equal, the lower unit costs will be, because both unit investment cost and unit operating expense decline. This is shown graphically on the following pages. Figure 1 shows the costs of the three main items in a steam generating station--building, boiler and turbine-generators.[1]

There is no "standard" turbine-generator set, but the 3600 rpm. single-shaft turbine-generator is available over the widest range of sizes, and it is used to facilitate cost comparisons.[2] One boiler per generator is assumed,[3] and building includes, in addition to that necessary to house turbine-generator and boiler, a prorated share of remaining power plant building costs.

The discontinuity occurring at 90 mw. is due to three things: First, a reheat cycle is added, which means that used steam (which has lost pressure and temperature in turning

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[1] These three items ordinarily constitute about 50 to 60 per cent of the total cost of a station. Other items are: site and preparation; docks or railroad tracks; fuel handling; cooling water supply; auxiliary equipment such as condensers, fans, pumps, controls, instruments; generator transformers with associated bus work and circuit breakers; switching station for outgoing lines. It is evident that much of these costs are independent of station capacity or are non-recurring within some limits, and hence total investment per kilowatt may decline even more sharply than Figure 1 would indicate.

[2] Above 90 megowatts, both 1800 rpm. and compound units (comprising separate high and low pressure units) are often used.

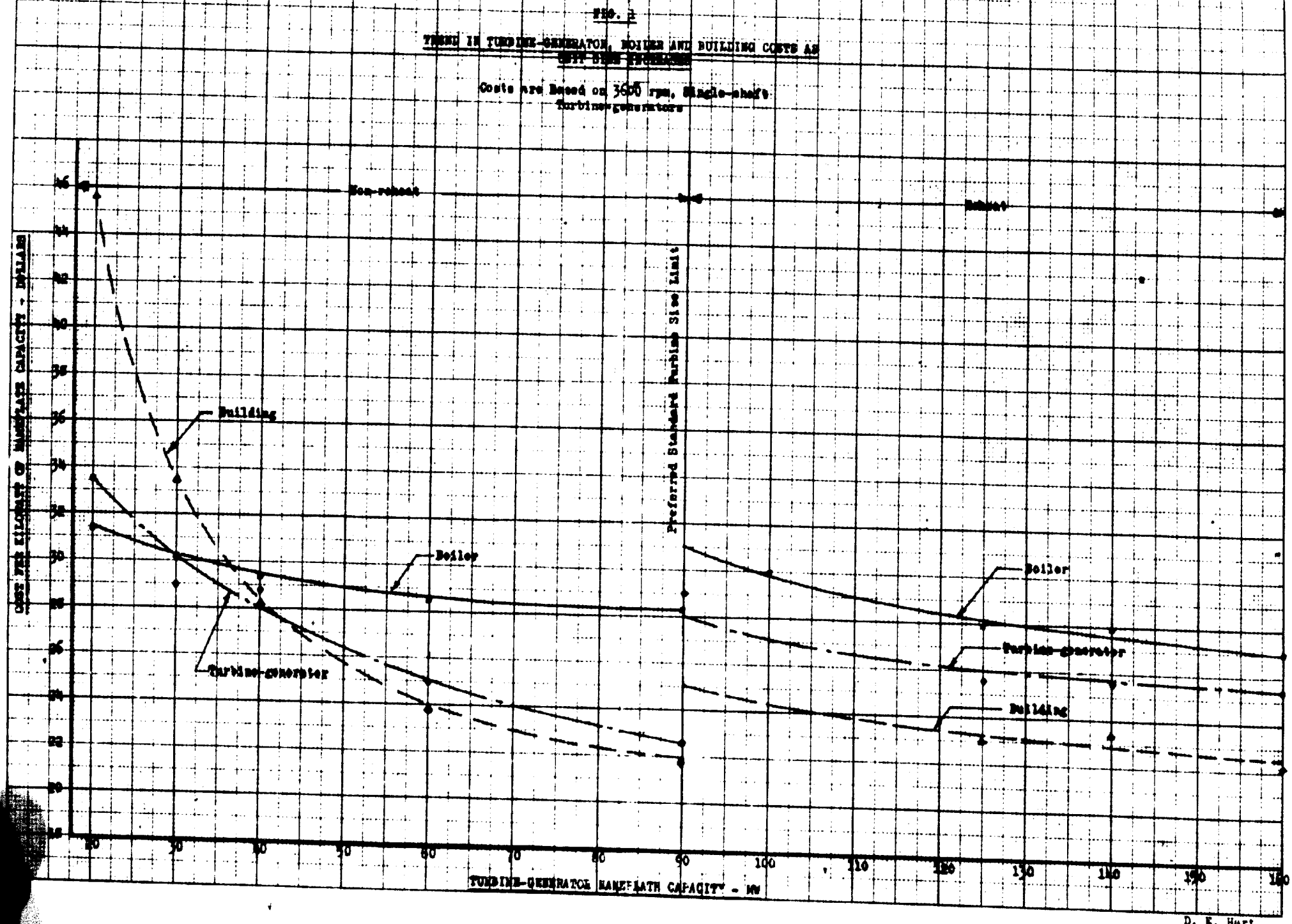
[3] Often, multiple boiler sets are used with one turbo-generator of large capacity because of more frequent maintenance work necessary on boilers, and other technical considerations.

D. Rosscheff

Fig. 2

TRENDS IN TURBINE-GENERATOR, BOILER AND BUILDING COSTS AS
UNIT SIZE INCREASES

Costs are Based on 3600 rpm, Single-shaft
Turbine-generators



D. E. Hurt
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the turbine) is returned to the boiler and reheated to approximately its original temperature. This is done to reduce the heat-rate (see Figure 2), but it increases the cost of both turbine-generator and boiler. Second, the preferred standard units (to about 90 mw.) have the cost advantages of production manufacture whereas the larger units are in general specifically designed. This increases their cost and may also result in less compactness and an attendant increase in site area, which increases building costs. Third, the data above 90 mw. size were derived from the planning and construction of a large steam generating station currently being completed, while data for the smaller sizes were obtained from an earlier study. Hence, there is probably some price-level differential. The downward trend in investment cost as unit size increases is clear.[1]

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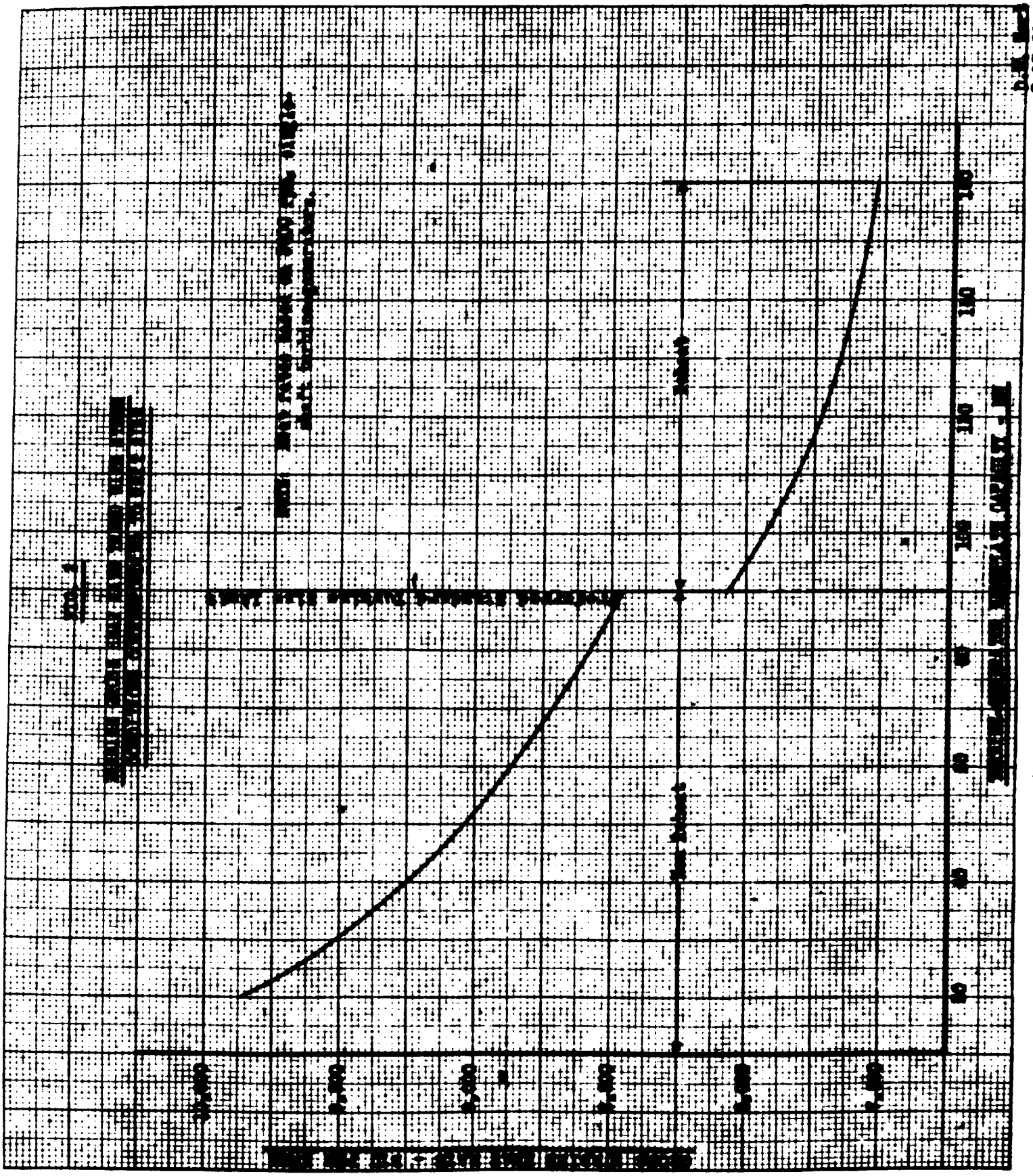
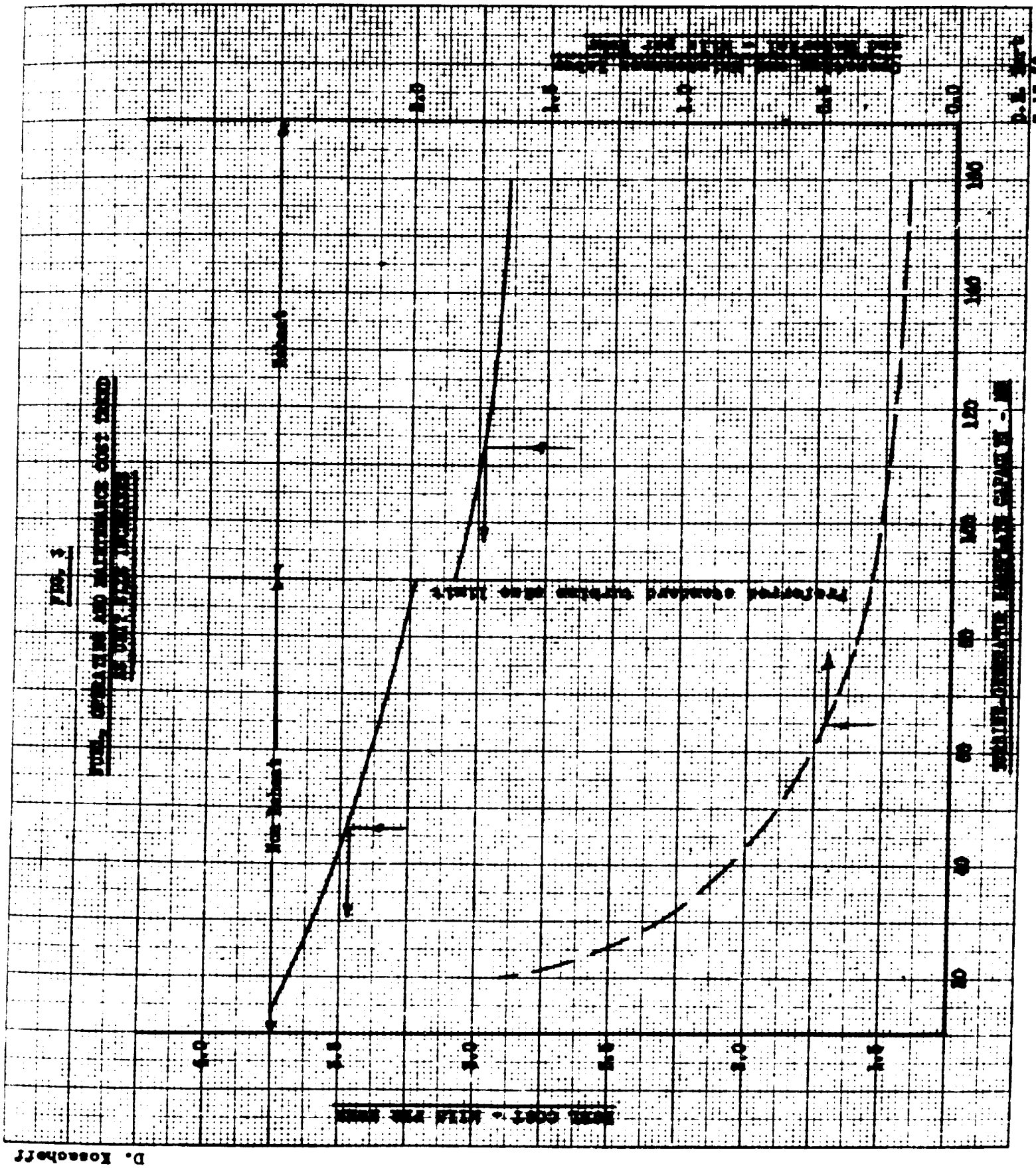
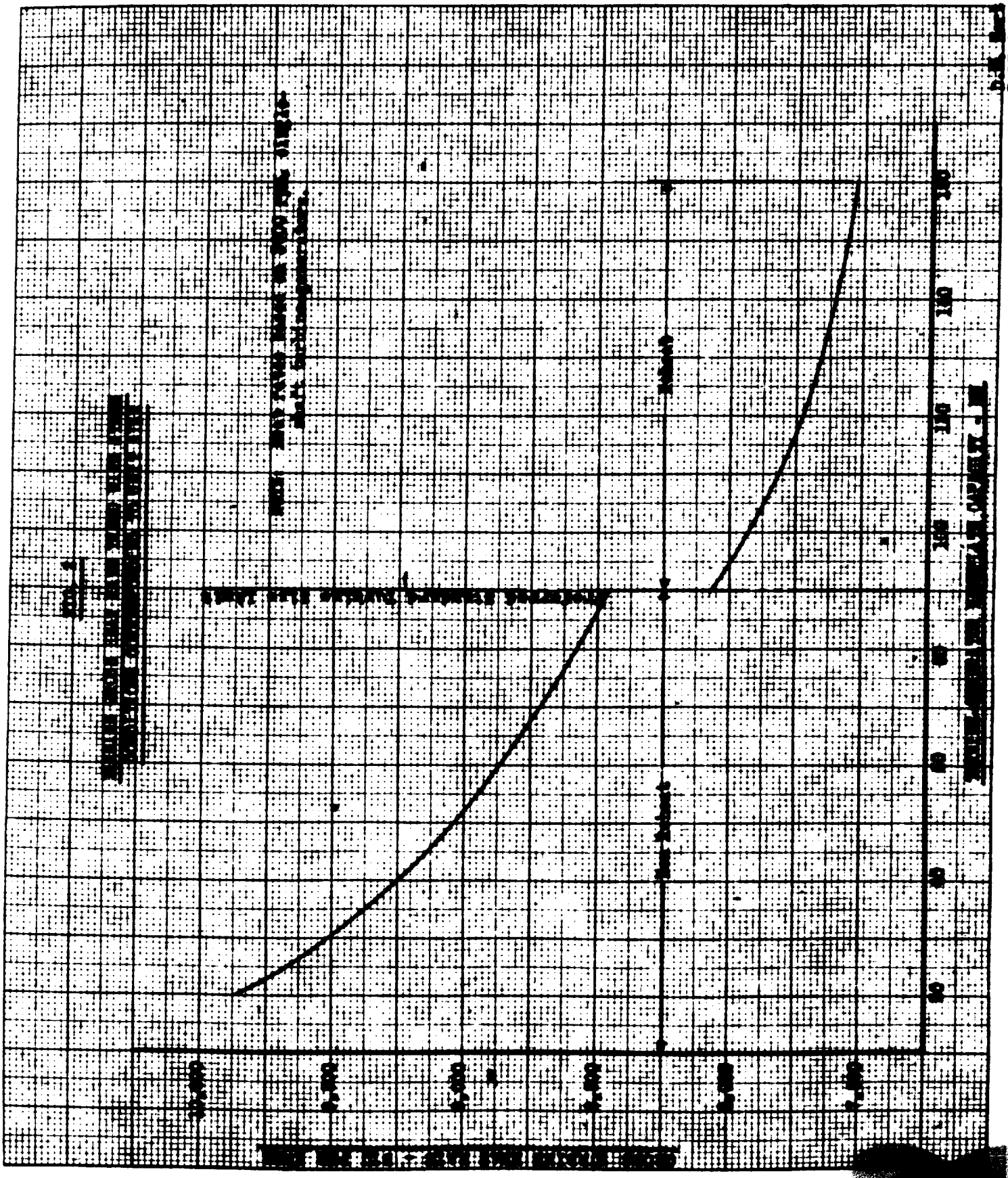
[1] J. B. McClure and A. G. Mellor, in a recent study, show a somewhat steeper trend in turbine-generator sets, and also show 3600 rpm. single shaft sets over the entire range to 160 mw. The difference seems to be that they assume constant steam pressure and temperature over the entire range, whereas in Figure 1, throttle steam conditions vary with the size of unit corresponding to the preferred standard ratings. "The Effect of Unit Size on Steam-Electric Generating Station Design," Electrical Engineering, Vol. 71, No. 2 (February, 1952), pp. 174-179. See p. 175.

John B. Lansing reaches the same conclusion on the basis of somewhat less comparable, but more widely available, data. "An Investigation of Economies of Large Size in Steam Stations," Land Economics, 27 (May, 1951), 108-122.

A recent paper on reheat turbine-generator sets shows a cost trend comparable to that shown in Figure 1 for units larger than 90 mw. Martin Frisch, "Steam-Generating Equipment for Resuperheating Cycles," American Society of Mechanical Engineers, Transactions, Vol. 71, No. 6, pp. 707-717.







The decline in fuel costs (the largest single production cost) as turbine-generator unit size increases is shown in Figures 2 and 3. Figure 2 shows the heat rate, which is the amount of fuel, in B.T.U's., necessary to generate one kwh. of electricity.[1] Figure 3 shows this as fuel cost in mills/kwh.[2] The discontinuity at 90 mw. is of course due to re-heat.

The operating and maintenance labor and materials cost also shown in Figure 3 is based on actual operating records. It includes not only plant maintenance personnel but also maintenance performed by the mobile maintenance crews. As the data show, the number of personnel is almost independent of unit size.[3]

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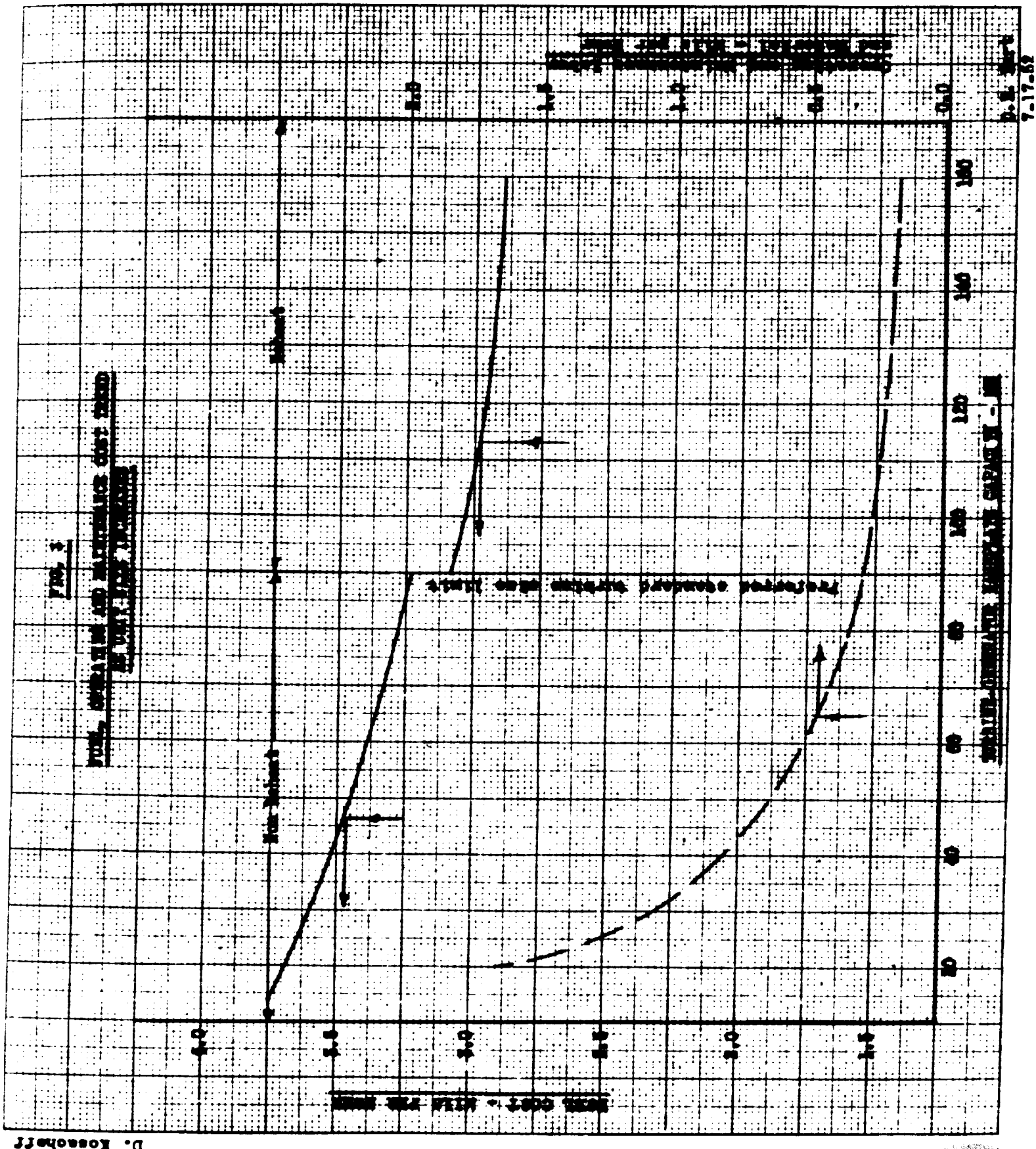
[1] For non-reheat units, steam temperature and pressure and feedwater heater cycle consistent with the size of unit are used (preferred standard conditions). For units over 90 mw., the assumptions are constant: throttle steam pressure and temperature of 1800 p.s.i.g. and 1000 F. with reheat to 1000 F., and a feedwater heater cycle employing seven heaters with a final feedwater temperature of 500 F.

[2] The assumptions made in this conversion were: a coal cost of 30.4 cents per million B.T.U., boiler efficiency of 88 per cent, auxiliary power requirements of 5 1/2 per cent and an annual plant factor of 70 per cent. Some plant factor, which is the ratio of actual output to capacity, must be assumed because any given size unit may have the familiar U-shaped average variable (fuel) short-run cost curve; at least it declines over a considerable range as plant factor is increased. Seventy per cent was felt to be a reasonable assumption for modern units. See Lansing, op. cit., pp. 114-115; Federal Power Commission, Electric Utility Cost Units and Ratios (Washington, 1938), p. 37.

[3] Personnel for a four-unit station is estimated to vary from about 150 to 180 men as unit size increases from 40 mw. to 160 mw., respectively.



D. Kossakoff

Thus, the larger the amount of electricity generated, the lower production costs may be. But capacity to meet peak demand is not enough; reserve capacity must be available at peak load because of the possibility of breakdown, or outage, of operating units.[1] It can be demonstrated by the use of probability mathematics that the amount of reserve capacity required for any given degree of assurance of continuity of service is in inverse relation to the number of generating units in a plant (interconnected system).[2] For example, if it is assumed that the average frequency of individual turbine-generator set outage is once in 2 years, its average duration is 1 week for repairs (based on spare boiler capacity), the average plant factor is 75 per cent, and the greatest average frequency with which an outage in excess of reserve can be endured is once in 30 years, a system containing 20 generators requires a 20 per cent reserve (in terms of system load), one with 40 generators requires about a 12 per cent reserve, and

[1] As a matter of fact, yearly peak load occurs only once--typically at about 5 p.m. on a day in mid-December. Thus, excess capacity exists the rest of the year, with summer ordinarily being the period of smallest load. However, scheduled routine maintenance ordinarily removes much of this excess capacity from possible use as reserve. Hence, reserve capacity over and above peak load will be necessary during a considerable part of the year. In so far as this is not so, the probability of needing extra capacity is reduced.

[2] For the mathematics involved, see, for example, Howard P. Seelye, "Outage Expectancy as a Basis for Generative Reserve," American Institute of Electrical Engineering, Transactions, 66 (1947), 1483-1488; "A Convenient Method for Determining Generation Reserve," ibid., Vol. 68 (1949), Technical Paper 49-278.

one with 60 generators requires about a 9 per cent reserve.[1] Thus, when two of the largest electric utilities, which had a combined total of nearly 50 generating units, became interconnected in order to provide each other with emergency stand-by, it was concluded that each could reduce its necessary reserve from about 15 per cent of capacity to about 10 per cent of capacity. At current prices, this would reduce the required plant investment on the order of $25,000,000, the only off-set to which is the interconnection cost.

Similar savings for other reasons can accrue by extending plant size. Operating companies may have different peak-load times. If such plants are interconnected, necessary peak-load capacity will be reduced. Also, interconnection will allow bringing units into use on the basis of marginal cost.[2] This is especially true if one company has appreciable amounts of unused hydro capacity during low load periods, since this may be used to displace steam power, at a marginal cost of zero.[3]

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[1] Howard P. Seelye, "What Reserves Should Be Provided in a Modern Power System," Proceedings of the Mid-West Power Conference, 12 (1950), 176-182.

[2] This is widely done in electric production, where the concept is called "incremental" or "incremental production" cost. See Lansing, op. cit., p. 116, and M. J. Steinberg and T. H. Smith, Economy Loading of Power Plants and Electric Systems (New York, 1943).

[3] This would ordinarily mean that the hydro capacity is of the run-of-river type; that is, water is not stored. Although less data are available, it appears that both

Therefore, it appears that the only economic reason why this country does not have a single electric plant is that interconnection costs may more than offset the production savings involved between any two systems or areas.[1]

Transmission lines are not inexpensive. In 1938, the average cost of building the cheapest type, a 11 kv. wood pole single circuit line, was $1,520 per line mile, while the most expensive type built that year, a 220 kv. steel tower double circuit, was $29,534 per line mile.[2]

It is evident that transmission costs are a function of distance and capacity. No doubt it is cheaper, per unit carried, to build high capacity, long lines, and it is probably cheaper per unit to maintain them. Since these are

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investment and production (variable) costs of hydro electric generating capacity decline in the same manner as steam capacity. Investment cost is higher, and operating cost lower than for steam. See Federal Power Commission, Electric Utility Costs Units and Ratios, pp. 11, 39.

[1] Interconnection costs include not only the cost of building transmission lines and necessary auxiliary equipment, but also line losses. The further electricity is transmitted, the more of it is lost. The longest direct transmission of electricity today is said to be between Boulder Dam and Los Angeles, a distance of 270 miles, and this is the highest voltage line presently in use--287 kv. By displacement of energy between generators, it of course may be indirectly transported further.

[2] Federal Power Commission, Electric Utility Costs Units and Ratios, p. 14. This figure does not include land costs, since there is clearly no relationship between the two. However, for the purpose of comparison, the average land cost per line mile of steel tower double circuit line was over $8,000.

determined by type of market served and technical considerations, it does not appear that transmission costs are a function of plant size, except in so far as they limit economic plant size.

Distribution costs also do not appear to be a function of plant size.[1] Both investment and operating costs attributable to distribution are in direct relation to the number of meters per mile of line.[2]

Accounting and collecting expenses are properly a part of electric distribution costs. Such data as are available (1938) show a cost per customer which declines and then increases as the number of customers served increases. For companies which served less than 5,000 customers the average annual cost per customer was $3.73. For companies with more than 500,000 customers, the comparable figure was $3.51. The lowest per-customer cost, $3.045, was for companies with between 30,000-100,000 customers.[3]

However, number of customers is not an accurate measure of plant size, since the proportion of household, commercial and industrial customers varies between companies of the same

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[1] Distribution is defined as the conveying of energy from the step-down transformers, at the end of transmission lines, to users via low-voltage lines.

[2] Source: Federal Power Commission, Electric Utility Costs Units and Ratios, pp. 21, 49.

[3] Ibid., pp. 52-53.

size, and company and plant size are not necessarily equal. In addition, it should be noted that there has been extensive mechanization of the billing process in large companies (e.g., the Detroit Edison Company) in order to reduce these costs.

Thus, the conclusion that it is economic to increase plant size until the reduction in generation cost is just offset by the increasing cost of interconnections, appears correct.

Minimizing plant costs is not merely a matter of physical interconnection. To achieve minimum costs, reserve capacity must be pooled, the planning and building of new capacity must be done on a plant-wide basis without regard for different corporate entities which may be involved, and output must be on the basis of lowest (marginal) cost units available.

There is a considerable amount of interconnection of electric utilities in this country, but the largest part of it appears to be on a unilateral contract basis--that is, the wholesaling of energy.[1] Probably some large portion of these contracts provide to some extent for emergency power interchange, but the extent of this is not known.

Power pool contracts by which separate legal entities,

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[1] See Joel D. Justin and William G. Mervine, Power Supply Economics (New York, 1934), p. 211, and Jones, op. cit., p. 120.

through the use of common dispatching, utilize lowest marginal cost generators without regard to ownership, may exist between subsidiaries of holding companies or non-affiliates. Comparatively little is known about the extent or content of these contracts, since the only ones generally available are those filed with the Federal Power Commission by member companies under its jurisdiction, but it seems generally believed that they usually do not provide for pooling capacity.[1] However, a number of pools between affiliates do provide for this.[2] The writer has access to one agreement between two otherwise independent electric companies which calls for coordination of the companies' power supply programs and sharing of system reserves "to the maximum extent [each company] deems consistent with the safe and proper operation of its system and the furnishing of economical, dependable and satisfactory service to its customers....." The contract calls for consideration of specific agreements in order to (1) supply power to each other so as to allow staggered construction schedules (since turbine-generators are of discreet sizes, this minimizes investment for the two systems), (2) supply reserve capability (this resulted in the decrease of reserve noted above at

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[1] Jones, op. cit., pp. 50, 120 ff.; Justin and Mervine, op. cit., pp. 211 ff.

[2] See case studies below, chaps. iii and iv.

page 27), (3) minimize generating costs.

Since the contents of such agreements are not generally available, their extent is not known. In any event, testimony of the president of the Niagara Hudson Power Corporation indicates that complete integration and coordination of production, and hence lowest cost, can best be achieved by a single corporate entity.[1]

It follows from this discussion that application of Section 11 (b) (1) can increase plant costs only if size of plant is decreased--that is, if interconnected operating companies are separated. And even then it cannot be assumed that losses will occur, since operating relationships may not change. Each such instance must be analyzed to determine the effects.

Firm Size

Firm is defined as the owning and controlling unit. Those costs connected with firm size are management and capital costs. While it is possible that some management costs which properly should be considered here are lumped into items already considered as plant costs, the Federal Power Commission's account "Administrative and general expense" contains the bulk of the relevant items.[2] It is

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[1] See below, n. 2, p. 38.

[2] Included are executive and other office salaries and expenses, management and supervision expenses, and legal expenses. The complete contents of the account are listed in the Appendix.

therefore considered to be the measure of management costs.

In 1938, this account, as a per cent of electric operating revenues, showed a consistent decline as size of operating company increased.[1] For the smallest companies reporting to the Federal Power Commission, those with revenues of between 1/4 and 1/2 million dollars, the average percentage was 8.1; while for companies with revenues of over 25 million dollars, the average percentage was 5.4.

Similar figures are available for 1939.[2] The results are generally the same as above. For operating companies with revenues of between 1/4 and 1/2 million dollars, the average percentage was 8.4; for those companies with revenues of over 20 million dollars (data for over 25 million dollars are not available), the average percentage was 6.3. However, the average percentage for those companies with less than 1/4 million dollars of revenues is available in this particular study, and it is 8.1 per cent--less than for the next two larger classes. However, the downward trend as company size increases is undoubted.

Size of operating company does not necessarily measure firm size. A subsidiary operating company is but a part of a

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[1] Federal Power Commission, Electric Utility Cost Units and Ratios, pp. 56-57.

[2] Merwin H. Waterman, Economic Implications of Public Utility Holding Company Operations, Michigan Business Studies, Vol. 9, No. 5 (Ann Arbor, 1941), p. 78. Source of the data was Federal Power Commission Reports.

larger firm--the holding company. Therefore, other comparisons are necessary, and Professor Waterman made them in this same study. Classifying operating companies on the basis of independents and subsidiaries, he found that the average percentage of general and administrative costs to electric revenues was higher for the former than for the latter--8.6 as compared with 7.3.[1]

Comparing independents and subsidiaries by size (in terms of revenues) of operating companies did not modify his conclusions. Unfortunately these data are shown only in graph form, but both independents and subsidiaries show a trend of declining percentage from the smallest to the largest size classifications, and the subsidiaries show a consistently lower percentage in each of the size groups than the independents averaging perhaps one percentage point less in each group.[2]

Waterman's study does not indicate that this trend holds when average percentages are compared on the basis of size (in terms of revenues) of holding company systems. While the smallest holding company systems, those with revenues under $2,000,000, show the highest average, 9.6 per cent, the next highest average, 8.5 per cent, is for the

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[1] Ibid., p. 27.

[2] Ibid., p. 81. It should be noted that the data are for 1939--four years after passage of the Act. Although integration had not yet been started, regulation had.

second largest systems, those with revenues of 120 million dollars to 160 million dollars. The largest systems, those with revenues exceeding 160 million dollars, have the third highest average--7.6 per cent. The lowest average, 6.3 per cent, is shown by the median size groups, those having revenues of 20 to 40 million dollars.[1]

Data on capital costs are less satisfactory. Waterman found it impossible to compare, over a period of roughly comparable market conditions, capital costs on the basis of either operating company size or holding company size. However, by using Securities and Exchange Commission data on cost of floatation of bonds and preferred stock of all types of corporations, on the basis of size, and the "confirmed opinion" that the bond market tends to accept lower yields from larger utility issuers, he concluded that there is an inverse correlation between issuer (operating company) size

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[1] Ibid., p. 85. The study notes that the samples may not be large enough to give statistical significance. Although the smallest size group contains 8 holding company systems, data were available for only 6 subsidiaries of those systems, and hence the average for this group is not very meaningful. There are only 2 systems in the largest size group, Cities Service Company and the North American Company. The average for Cities Service subsidiaries was 9.4 per cent, while for North American's it was 5.3 per cent. This difference may be due to difference in efficiency of holding company management or average size of subsidiaries. (Actually, North American's subsidiaries were considerably larger than Cities Service's.) The number of systems in each of the other classifications varied from 3 to 9. However, this does not change the negative conclusion drawn from the available data.

and capital costs.[1]

Sufficient data were available to compare capital costs as between subsidiaries and independents for the years 1938-1939. For mortgage bond money, there was no significant difference between the two groups over the period on the basis of either average net cost to issuer or average yield to investor.[2] Nor was any significant difference found in the cost of preferred stock money as between the two groups.[3]

Therefore, it appears that firm costs are associated primarily with size of operating company. Only if this is reduced by application of the integration requirements of the Act is there much possibility of increase in firm costs. The possibility of increasing firm costs through a reduction in holding company size may be anticipated, if at all, only in the area of administrative and general expenses.[4]

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[1] Ibid., pp. 90-92, 98. The "confirmed opinion" was based on the decreased risk due to diversified load of larger companies and increased liquidity of larger issues (which tend to reflect a larger size of issuer).

[2] Ibid., pp. 33-38.

[3] Ibid., pp. 38-40.

[4] This is substantially Waterman's conclusion on the subject. He states (at p. 108): "Tests of managerial economy tend to show similar and parallel increases in efficiency measured by costs of management with increasing company size. .... There is no evidence in the sample of the utility industry here considered which casts aspersions on the reasonable expected increasing economies of size measured in the management phases of utility operation. While there is much less to be said, if anything, for economies in management accompanying increasing size of the holding company system, on the other hand, there is certainly no evidence of detrimental increases

The holding company structure itself gives rise to costs. Some data are available to determine their magnitude. The Niagara Hudson Power Corporation, a holding company controlling three large subsidiaries in the state of New York, was simplifying its corporate structure to meet the requirements of Section 11 (b) (2). In so doing, it was decided to merge the system into one operating company and thus eliminate the need for the holding company. Since the subsidiaries all were located in the same state, this could be accomplished. In hearings before the New York Public Service Commission, whose permission was required, it was estimated that annual savings from consolidation would eventually amount to approximately one million dollars, or about .75 per cent of system gross operating revenues.[1]

The savings were expected to accrue from three sources. First, a reduction in the number of reports required for public authorities, such as regulatory commissions and tax bureaus, and the elimination of the many intercompany contracts and

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in costs; it appears that no true relationship exists on this score."

It should be said that Waterman's study was an attempt to determine whether holding companies subsidiaries had higher costs than independents. The conclusion was that they did not.

[1] Petition of Buffalo Niagara Electric Corporation et al., Case 12733, May 5, 1948. Revenue figures taken from Securities and Exchange Commission Holding Company Act Release 9270, appendices B and D.

arrangements which required conferences and much paper work.[1] Second, an increase in production efficiency and economy, which could be obtained only by a single corporation because of the greater flexibility thus made possible, as compared with intercompany contracts.[2] Third, a reduction in financing costs because of the more advantageous use of available funds.[3] The system was so certain of this estimate that it offered to reduce rates by the same amount at the time the state Commission's approval was obtained. This was done in January, 1949.[4]

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[1] "Hundreds of these transactions from month to month often result in complications requiring much time of officers and staff, and cost money." Ibid., p. 34.

[2] The president of the system stated: "even though you have a unified management in a system of this kind you do not necessarily get the same degree of coordination and utilization of these possible facilities as you would have in one corporate entity." Ibid., p. 35.

The statement was made even though planning, construction and operation had been on a system basis since 1930. There had been system forecasting, load supervision and dispatching.

[3] "Efficiency and low costs may result from the ability to use funds advantageously. For example, it was pointed out that it will probably be necessary for New York Power to make smaller expenditures than Buffalo Niagara and that New York Power will accrue over $3,000,000 of depreciation funds annually, all of which it will not need to use immediately. With separate corporations this money would not so promptly be available to other parts of the system, such as Buffalo Niagara, as in a unit system. However in one corporation, all depreciation funds would be available to all parts of the system for proper corporate purposes. With good management a consolidated corporation might through such utilization of all its available funds, defer or possibly avoid altogether borrowing money that three separate corporations might otherwise have to borrow." Ibid., p. 35.

[4] Holding Company Act Release 9270, p. 14, n. 14.

Comparable cost estimates are available for one other holding company system, that of Middle South Utilities.[1] There, the estimated cost of operating a new holding company not then in existence amounted to $763,000, or slightly less than 1 per cent of gross operating revenues of the companies which were to become subsidiaries. Thus any direct increase in firm costs attributable to separation from a holding company system will be offset, to some extent, by the elimination of this particular cost.

It therefore appears that attention should be centered on the administrative and general expense account of divested subsidiaries in order to determine whether firm costs have been increased as a result of separation. In the case studies in the next two chapters, changes in this account are measured for divested firms, and the results are compared with changes for all electric utilities in the United States for the same periods. It did not seem useful to use absolute changes in this account, since such a measure would not eliminate the effects of physical output and price level changes. It might seem that a solution would be to calculate administrative and general expense per kilowatt-hour of output. However, this would not eliminate the problem of inflation, and in addition would introduce another possible bias, since some utilities purchase energy from others, and there is no available way of

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[1] See below, p. 131.

determining whether interchanges between subsidiaries and independents would cancel each other. To overcome these objections, the account is compared with gross electric operating revenue.

The method used is as follows. For every subsidiary, administrative and general expense (less the pension subaccount[1]) is calculated as a percentage of electric revenue for every year for which data are available--generally, 1938-1950. In order to find the effect of divestiture on cost, these percentages are averaged for the years the utility was a subsidiary of a holding company, and also for the years after separation. The percentage change between these two averages is then calculated. Since, in the typical case, scale of output has changed, it is necessary to compare this figure with the comparable percentage change for all utilities as between the same two periods.[2] This final comparison shows whether or not administrative and general expenses of a subsidiary increased after separation relative to what happened to this account for all utilities.

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[1] The pension account is omitted from administrative and general expense in order to eliminate another bias. See Appendix.

[2] This was determined by summing the administrative and general expense account for all companies contained in the U. S. Federal Power Commission's Statistics of Electric Utilities of the United States (Washington, 1938- (annual)) and dividing this total by total gross electric operating revenues for that year. This was done for each of the thirteen years. The remaining calculations were done as above. See Appendix for these data.

Even though the averaging tends to eliminate non-recurring changes in any company's account over the period, the measure is probably not very significant in any one case due to the possibility of different timing of rate adjustments by the several regulatory agencies. However, if it is true that separation increases these costs, data for divested subsidiaries will show a relative increase compared with all companies. If the data do not show a general relative increase, it can be presumed that separation did not increase these firm costs.

It might seem that it is not significant to compare administrative and general expenses with electric revenues, since revenues will change in the same direction as expenses. This is not a valid criticism here, however, since this particular cost is such a small percentage of electric revenue. To illustrate: if the administrative and general expense account is 5 per cent of revenue (a typical figure), a doubling of this particular cost due to, say, separation, will result in the account becoming more than 9.5 per cent of revenue, even if the dollar volume of revenue is increased by the amount of this cost increase.

However, the fact that subsidiaries data are included in the "all companies" total tends to blur a concerted change in the former, since this will cause a (smaller) change, although in the same direction, in the latter. The effect is to reduce somewhat the sharpness of the comparison.

CHAPTER III

EFFECTS OF DIVESTITURE ON COSTS--CASES OF CLAIMED ECONOMY LOSSES

The purpose of this, and the following chapter, is to determine what the effects of Commission divestiture orders, arising from the Act's geographic integration requirements (Sec. 11 (b) (1)), have been on the costs of affected electric utilities. Each system which has been involved in Section 11 (b) (1) proceedings is studied separately. This chapter contains cases in which the systems involved have claimed that the Commission orders would result in the loss of economies to some or all of their electric subsidiaries. The next chapter contains those cases in which no loss of economies to subsidiaries was claimed. The cases within each group are listed alphabetically, purely for convenience.

Section 10 (c) (2) of the Act permits systems, upon obtaining Commission approval, to acquire non-affiliated operating utilities, if the results will be an economic, integrated system. Therefore, such cases have been included in the study of the various systems, since they too enter into the question of the effects of forced integration.

Since the complete record of testimony is not available,

data has been obtained primarily from Holding Company Act Releases of the Securities and Exchange Commission, which contain the orders of the Commission and the reasoning behind them, together with a certain amount of testimony. Citation is made to the Releases and not to the Decisions and Reports of the Commission for two reasons: (1) not all of the Releases are reprinted therein; (2) Decisions and Reports are not yet available for 1946 and following years.

Associated Gas and Electric Corporation (Now General Public Utilities Corporation), A Subsidiary of Associated Gas and Electric Company

This group was one of the latecomers into the utility holding company field. By 1929 it was a billion dollar corporation (in terms of control).[1] Its subsequent history was at least as spectacular, with its principal promoter jailed for fraud and the system itself going into bankruptcy.

Section 11 (b) (1) hearings were instituted in 1941. As of then, the system controlled 175 subsidiaries, of which 68 were gas or electric operating companies, located in 25 states and the Philippine Islands. The consolidated book assets were slightly more than 1 billion dollars at the end of 1940. No breakdown is obtainable on the amount of electric plant. During 1940, total operating revenue amounted to 142 million dollars, and electric operating revenue to more than

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[1] Bonbright and Means, op. cit., p. 118.

EXHIBIT B(1)

ASSOCIATED GAS AND ELECTRIC COMPANY SYSTEM

ELECTRIC UTILITY SUBSIDIARIES AND AREAS SERVED
AS AT DECEMBER 31, 1940

NO.	COMPANY	STATE
1	ARIZONA GENERAL UTILITIES CO.	ARIZ.
2	ARKANSAS GENERAL UTILITIES CO.	ARK.
3	ASSOCIATED MARYLAND ELECTRIC POWER CORP.	MD.
4	BRADFORD ELECTRIC CO.	PA.
5	BROOKVILLE ELECTRIC CO.	IND.
6	CARIBOU WATER, LIGHT & POWER CO.	ME.
7	EASTERN SHORE PUBLIC SERVICE CO.	DEL.
	DELMARVA POWER CO., THE	MD.
	EASTERN SHORE PUBLIC SERVICE CO. OF MD., THE	MD.
	EASTERN SHORE PUBLIC SERVICE CO. OF VA.	VA.
	MARYLAND LIGHT & POWER CO., THE	MD.
8	EDISON LIGHT & POWER CO.	PA.
9	FLORIDA POWER CORP.	FLA.
10	FLORIDA PUBLIC SERVICE CO.	FLA.
11	GENERAL UTILITIES CO., THE	OHIO
12	GEORGIA POWER & LIGHT CO.	GA.
13	GREENWICH ELECTRIC LIGHT & POWER CO.	PA.
14	GRANVILLE ELECTRIC CO.	VT.
15	KENTUCKY-TENNESSEE LIGHT & POWER CO.	TENN., KY.,
16	KEYSTONE PUBLIC SERVICE CO.	PA.
17	LEXINGTON WATER POWER CO.	S.C.
18	LITCHFIELD ELECTRIC LIGHT & POWER CO., THE	CONN
19	LOGAN LIGHT, HEAT & POWER CO.	PA.
20	LOUISIANA PUBLIC UTILITIES CO., INC.	LA.
21	MARYLAND PUBLIC SERVICE CO., THE	MD.*
22	METROPOLITAN EDISON CO.	PA.
23	MISSOURI GENERAL UTILITIES CO.	MO.
24	MISSOURI SOUTHERN PUBLIC SERVICE CO.	MO.
25	NEW MATAMORAS ELECTRIC CO., THE	OHIO
26	NEW JERSEY POWER & LIGHT CO.	N.J.
27	NEW YORK STATE ELECTRIC & GAS CORP.	N.Y.
28	NORTHERN PENNSYLVANIA POWER CO.	PA.
	PENELEC ELECTRIC LIGHT & POWER CO., THE	N.Y.
29	OHIO-MIDLAND LIGHT & POWER CO., THE	OHIO
30	OHIO NORTHERN PUBLIC SERVICE CO., THE	OHIO
31	OHIO RIVER POWER CO.	IND.
32	PANHANDLE PUBLIC SERVICE CO.	OKLA.
33	PATCHOGUE ELECTRIC LIGHT CO., THE	N.Y.
34	PENNSYLVANIA EDISON CO.	PA.
35	PENNSYLVANIA ELECTRIC CO.	PA.
	CLARION RIVER POWER CO.	PA.
	ERIE LIGHTING CO.	PA.
36	ROCHESTER GAS & ELECTRIC CORP.	N.Y.
37	SOLAR ELECTRIC CO.	PA.
38	SOUTH CAROLINA ELECTRIC & GAS CO.	S.C.
39	STATEN ISLAND EDISON CORP.	N.Y.
40	TEXAS GENERAL UTILITIES CO.	TEXAS
41	TIDE WATER POWER CO.	N.C.
42	VIRGINIA PUBLIC SERVICE CO.	W. VA. VA.,*
	HARPERS FERRY PAPER CO., THE	W. VA.
43	WEST VIRGINIA LT., HEAT & POWER CO.	W. VA.
44	WESTERN RESERVE POWER & LIGHT CO.	OHIO
	NEW LISBON POWER CO., THE	OHIO
45	YOUGHIOGHENY HYDRO-ELECTRIC CORP.	MD.

*PRIOR TO DECEMBER 31, 1940 MARYLAND PUBLIC SERVICE CO. (21) SOLD ITS PROPERTIES OUTSIDE THE SYSTEM AND WAS THEREUPON DISSOLVED AND VIRGINIA PUBLIC SERVICE CO. (42) ORGANIZED A VIRGINIA SUBSIDIARY, VIRGINIA PUBLIC SERVICE GENERATING CO. (OCTOBER 17, 1940).

114 million dollars.[1]

On August 13, 1942, the trustees proposed a voluntary plan of compliance with the Act. It contemplated elimination of the top holding company; a proposal to carve four of what the trustees considered to be separate integrated electric utility systems from the operating companies and to dispose of them by "distribution to security holders or otherwise"; and the disposal of all other properties. The four groups alleged to meet the standards of the Act as integrated systems were: (1) the New York-Northern Pennsylvania group; (2) the Eastern Pennsylvania-New Jersey group; (3) the Western Pennsylvania group; and (4) the Florida-Georgia group.

The Commission did not face the issue of whether these four systems met the requirements of the Act until after the whole system had emerged from bankruptcy, but did order the divestment of the other properties, since there was no claim or proof that any were retainable under the "ABC" provisions. Thus 31 operating companies in 17 states were required to be divested.[2] The bulk of these companies were quite small. Most of the small ones were sold to municipalities, cooperatives, TVA, or individuals.[3] However,

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[1] Holding Company Act Release 2983.

[2] Holding Company Act Release 3729.

[3] Moody's Manual of Public Utilities (New York, 1941-1951).

Associated Maryland Electric Power Company was sold to the Potomac Edison Company, Granville Electric Company was obtained by Central Vermont Public Service Company, Litchfield Electric Company was acquired by Connecticut Light and Power Company, and West Virginia Light, Heat and Power Company was sold to Monongahela Power Company. Of the larger companies, Virginia Public Service Company was sold to Virginia Electric and Power Company,[1] the stock of South Carolina Electric and Gas Company was distributed as a partial liquidating dividend in 1946,[2] the system's holdings in the Florida and Georgia companies and Tidewater Power Company were lost upon their recapitalizations,[3] and Eastern Shore Public Service Company was traded to the United Gas Improvement Company for Erie County Electric Company.[4]

The details of this acquisition are as follows: Erie County served the city of Erie, Pennsylvania, and adjoining townships along with Pennsylvania Electric Company, a subsidiary of Associated Gas and Electric, and the service

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[1] At the time of the sale, Virginia Electric was a subsidiary of Engineers Public Service Company. See below, p. 152.

[2] Holding Company Act Release 6915.

[3] Holding Company Act Release 6124.

[4] Holding Company Act Release 4505. See p. 265 below, for United Gas Improvement Company's acquisition of Eastern Shore.

area of the former was virtually surrounded by the latter. Erie County served the larger proportion of residential customers, while Pennsylvania Electric supplied most of the industrial users in the city. The two companies were interconnected, and there had been interchange of small amounts of energy. It appeared that Erie County, in the near future, would require additional boiler capacity. At the time of the Commission decision, Pennsylvania Electric was installing new generating capacity at its Erie plant. Pennsylvania Electric's acquisition of Erie County would mean that the latter would not need to install new boilers. It was anticipated that all of the two companies' needs would be generated at Pennsylvania Electric's plant, with Erie County's plant relegated to stand-by. There had been, of course, a considerable duplication of transmission and distribution facilities by the two companies. The acquisition would result eventually in the elimination of this.

For these reasons, the Commission approved the acquisition. Erie County was later merged into Pennsylvania Electric.

On January 1, 1946, General Public Utilities Corporation emerged as the surviving company in the joint reorganization in bankruptcy of Associated Gas and Electric Company and Associated Gas and Electric Corporation.[1]

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[1] Holding Company Act Releases 4985 and 6915.

On January 3, 1949, the Company advised its stockholders that it had reviewed the situation, "in order to determine, in the light of the impact of the Act, which groups of properties would best serve the interests of stockholders, bearing in mind the nature of dispositions required and the financial problems confronting" the system.[1] The decision was to dispose of the New York properties and retain under unified holding company control the Pennsylvania and New Jersey properties. This decision was probably based on the findings of the Public Utilities Division of the Commission that the combined New York-New Jersey-Pennsylvania properties were not retainable as a group. The Division did, in fact, make this recommendation later to the Commission.

For whatever reason, the Company determined to dispose of Rochester Gas and Electric Corporation and New York State Electric and Gas Corporation, by issuing subscription warrants for the common stock of these two companies to the stockholders of General Public Utilities.

In deciding on the proposed divestment of New York State,[2] the Commission concluded that both it and Rochester were of sufficient "size and scope" to operate economically and efficiently as independents. There were, and are, no

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[1] Holding Company Act Release 8924.

[2] Ibid.

significant operating relations between the two.[1] The Commission felt that "on the basis of the record, there appears to be no question," that under Section 11 (b) (1), New York State was not retainable with any system property except Northern Pennsylvania Power Company, and possibly Rochester. The Commission saw no problem with respect to separating New York State from the main group and from Rochester (and the same was said of Rochester), but it had doubts about separating New York State from Northern Pennsylvania. The latter's property area was contiguous with New York State alone of all the companies in the system, and Northern Pennsylvania, tied to New York State's transmission lines at seven points along the New York-Pennsylvania border, was interconnected with that company alone in the system.

At the end of 1948, the fixed electric property at original cost of New York State was about 130 million dollars, compared with 12 million dollars for Northern Pennsylvania. In the same year, electric operating revenue for the former company was more than 38 million dollars, while for the latter company it was less than 4 1/2 million dollars. Northern Pennsylvania served about 36,000 customers while New York State had more than ten times as many. The two companies

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[1] At one time, General Public Utilities apparently contemplated that it might attempt to interconnect them so as to create a basis for their joint control and operation. Evidently this was found to be uneconomic, since it has not been started to date.

had been under common control since 1926, and since that date New York State had been supplying the bulk of the other's energy requirements. In 1948, for example, New York State supplied 150,663,000 kwh. of energy out of a total of 159,616,000 kwh. used by Northern Pennsylvania, which did not generate all of the rest, but purchased some from other sources. The power is interchanged by an agreement which does not expire until 1955 at the earliest. The contract requires delivery of firm power by New York State to supply Northern Pennsylvania requirements in its service area at least until that time.

In addition, New York State did the meter supervision and routine billing of customer accounts for Northern Pennsylvania, which hired, on a part-time basis, New York State's power sales promotion engineer and safety director. In 1948, the aggregate payments for these services were $35,767, or about .75 per cent of Northern Pennsylvania's gross electric operating revenue.

Some services were also rendered to Northern Pennsylvania by another company in the system--Metropolitan Edison--which did general accounting, internal auditing, tax problems, forcasting of cash receipts and expenditures, treasury and secretarial work, and some legal work connected with land titles and bond indentures. In 1948, Northern Pennsylvania paid $43,751 for these services, almost 1 per cent of its gross electric operating revenues.

On the basis of the above information, the Commission

concluded it would have "no difficulty" in determining that both were retainable under common control under Section 11 (b) (1). But since General Public Utilities had asked to separate them, the question was whether this would be inconsistent with the Act. In view of what was to be said later, testimony on this point is interesting. The president of Northern Pennsylvania testified that his company could feasibly be operated as an independent entity. If the power supply from New York State were not available after 1955, he said that his company would be "in a position to construct its own generating facilities." The financial vice-president of General Public Utilities testified concerning this point that Northern Pennsylvania could finance its future capital needs and that it could function as an independent entity. The main support for these contentions was that the common stock equity in Northern Pennsylvania amounted to more than 44 per cent of the total capital, with the balance in first mortgage bonds, thus putting the company in a (presumably) strong financial position.

The Commission decided not to overrule the judgment of the management. The decision to let New York State be divested was based on the testimony that Northern Pennsylvania could stand by itself. It was pointed out in the decision that although Northern Pennsylvania had not been ordered separated from General Public Utilities' system--because, it was said, of the "incompleteness of the record"--this was not

to be construed to mean that Northern Pennsylvania was retainable. The implication was that it would take a great deal of persuasion to allow it to be retained. New York State was disposed of by the distribution of stock subscription warrants to the stockholders of General Public Utilities in 1949.[1] Similarly, in the same year, the same method was used in disposing of the Rochester property.[2] As noted above, there was no question concerning separation of Rochester from the system. The retention of Staten Island Electric Company, the remaining New York property in the system, was never considered. It was sold to Consolidated Edison Company of New York in 1950.[3]

The question of whether the remaining companies in the General Public Utilities system met the standards of Section 11 (b) (1) was finally decided on December 28, 1951.[4] It was the view of the Division of Public Utilities that the Pennsylvania-New Jersey system was an integrated public utility system within the meaning of the Act, but that Northern Pennsylvania could not be retained with it, and hence must be divested.

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[1] Moody's Manual, 1951.

[2] Holding Company Act Release 9296, and Moody's Manual, 1951.

[3] Moody's Manual, 1951.

[4] Holding Company Act Release 10982.

General Public Utilities, upon completion of the statement of the Division, stated that it would not oppose such an order. However, the Commission had to determine whether the Division's views would meet the standards of Section 11 (b) (1). The question of whether Northern Pennsylvania was retainable, either as a part of the main system or as an additional system, will be considered first.

The Commission determined that Northern Pennsylvania (and its subsidiary[1]) was not part of the main system. It is still not interconnected with any other system company and General Public Utilities conceded that, at the time of the hearings, it was not economically capable of being interconnected. Preliminary surveys were made concerning three possible ties, each about 90 miles in length. They indicated that it would not be worthwhile even to make a detailed survey. Therefore, the question was one of meeting the "ABC" requirements.

In order to show loss of "substantial" economies, General Public Utilities presented a severance study as evidence. Northern Pennsylvania's income statement for the fiscal

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[1] Waverly Electric Light and Power Company is a wholly owned subsidiary serving as a distributor of electricity in and around the town of Waverly, New York, just across the state line from Northern Pennsylvania's service area. It is probably a separate legal entity because it is in another state. It is completely integrated with Northern Pennsylvania, is of negligible size, and hereafter will be considered as a part of Northern Pennsylvania.

year of 1949 was adjusted to show what it would have been, had the company been independent. The result was an estimated increase in costs of $57,890, 1.44 per cent of gross electric operating revenue.[1] It was stated that this increase in costs was due to the "estimated increase in operating expenses, depreciation[!] and miscellaneous taxes." How the figure was arrived at is not set forth in the Release.

The Commission did not question the figures, but stated they were not large enough to meet the requirements of clause (A):

> The .... table clearly indicates that when measured by yardsticks established in administrative precedents in which claims to alleged losses of substantial economies were rejected, the instant proceeding presents, in all respects, an a fortiori case. Accordingly, General Public Utilities' claims here must likewise be rejected.

The essentials of the table mentioned are reproduced below:

TABLE 1

PER CENT OF ESTIMATED LOSSES OF ECONOMIES TO OPERATING REVENUE

Engineers Public Service Company	Engineers Public Service Company	North American Company	Philadelphia Company	General Public Utilities
Gas properties of Gulf States Utilities Co. 1940	Gas properties of Virginia Electric & Power Co. 1940	Gas properties of St. Louis County Gas Co. 1942	Gas group 1946	Electric properties of Northern Pennsylvania
6.58%	3.38%	5.85%	3.00%	1.44%

[1] The Commission excluded Federal income tax differences due to loss of consolidation of tax statements. As had been made clear in other decisions, it felt that this point should not be considered, since tax laws might change, and also because these savings could be obtained by completely unrelated companies filing consolidated returns.

This is the first instance of the Commission basing a decision on precedents alone.

Another alleged loss of firm economies was based on the testimony of an "expert witness" who believed that the cost of obtaining equity capital would be more than 15 per cent higher for an independent Northern Pennsylvania than for General Public Utilities. This conclusion was reached by comparing capital costs of a number of independent utilities, which the expert believed to be comparable with Northern Pennsylvania, with the cost to General Public Utilities of obtaining capital.

The Commission thought that some of the companies picked by the expert were not comparable with Northern Pennsylvania, and, of course, the testimony in the previous decision did not seem to indicate the above result.

The Commission went on to point out that even if the estimate were correct, no data were given as to how much annual equity financing, if any, was anticipated. Therefore, it could not tell whether or not this would add to the claimed loss of economies to such an extent as to be significant.

The Commission concluded that, "no new evidence has been submitted which affects the former conclusion as to the ability of Northern Pennsylvania Power Company to operate as a separate entity." General Public Utilities was ordered to dispose of Northern Pennsylvania.[1]

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[1] This has not as yet been done.

Having disposed of this question, the problem was whether the remaining Pennsylvania and New Jersey properties were an integrated system (or systems). The map on the next page shows their service areas, which contain an estimated 2,700,000 population. As of December 31, 1950, their gross electric plant at original cost was 384 million dollars, and during that year the electric operating revenue was about 101 million dollars. Practically all their capacity consisted of steam plants, which had an effective capability of over 1 million kw. in 1951.

Prior to July 2, 1950, there was no interconnection between Pennsylvania Electric and other companies in the system, although the service areas are contiguous for a short distance. Pennsylvania Electric itself was completely interconnected, with a central load dispatcher at Johnstown. The other properties were all interconnected, with a central load dispatcher at Reading, although their combined service area is broken into three separate parts by foreign companies. In each of the two areas, the dispatcher brought new units into generation as needed, on the basis of the lowest (remaining) marginal cost.[1]

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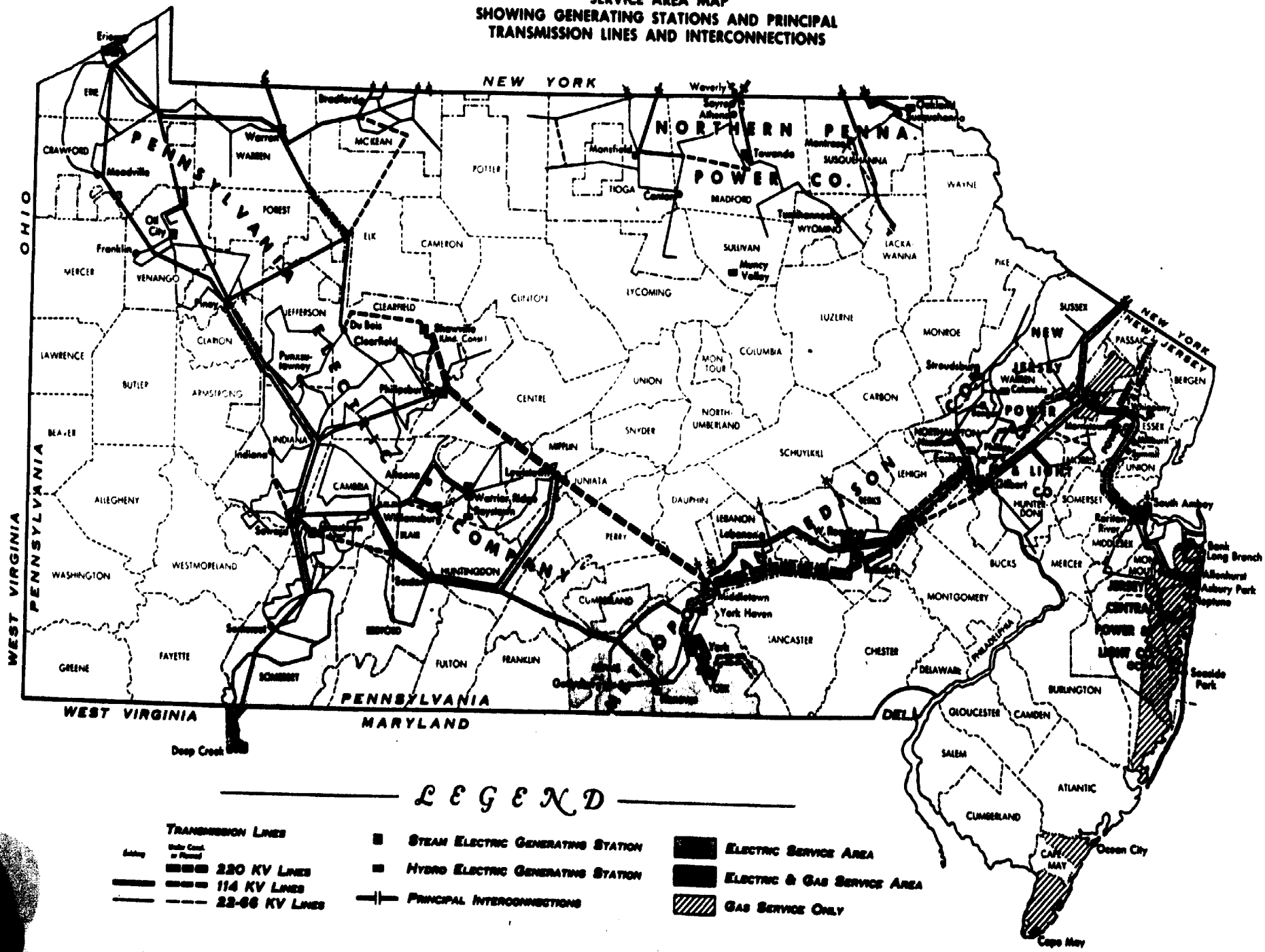
[1] The Eastern group was part of a power pool, together with Public Service Electric and Gas Company (with which that part of General Public Utilities was interconnected at two points) and, through Public Service, with Philadelphia Electric Company and Pennsylvania Power and Light Company. Known as the Pennsylvania-New Jersey Interconnection, the pool had an intercompany dispatcher who advised on the marginal costs of unused units so that the lowest operating cost unit

GENERAL PUBLIC UTILITIES CORPORATION

PENNSYLVANIA - NEW JERSEY

SERVICE AREA MAP
SHOWING GENERATING STATIONS AND PRINCIPAL TRANSMISSION LINES AND INTERCONNECTIONS


NEW YORK
OHIO
WEST VIRGINIA
PENNSYLVANIA
MARYLAND
NORTHERN PENNA. POWER CO.
METROPOLITAN EDISON COMPANY
JERSEY CENTRAL POWER & LIGHT CO.
PENNSYLVANIA ELECTRIC COMPANY
NEW JERSEY POWER & LIGHT CO.
Erie
Meadville
Oil City
Franklin
Warren
Bradford
McKean
Potter
Tioga
Mansfield
Towanda
Montrose
Susquehanna
Wayne
Pike
Wyoming
Lackawanna
Sullivan
Lycoming
Clinton
Luzerne
Monroe
Sussex
Passaic
Bergen
Mercer
Venango
Forest
Elk
Cameron
Clearfield
Du Bois
Jefferson
Clarion
Lawrence
Butler
Armstrong
Indiana
Cambria
Allegheny
Washington
Westmoreland
Fayette
Greene
Somerset
Bedford
Fulton
Franklin
Cumberland
Perry
Juniata
Mifflin
Centre
Union
Snyder
Northumberland
Columbia
Montour
Schuylkill
Carbon
Lehigh
Berks
Dauphin
Lebanon
Lancaster
York
Adams
Chester
Delaware
Montgomery
Bucks
Somerset
Hunterdon
Warren
Mercer
Middlesex
Monmouth
Burlington
Camden
Gloucester
Salem
Cumberland
Atlantic
Cape May
Ocean City
Seaside Park
Long Branch
Asbury Park
Neptune
Deep Creek
Conemaugh
Keystone
Shawville
Warrior Ridge
Portland
Saltsburg
Homer City
Seward
Blairsville
Indiana
Altoona
Lewistown
Williamsport
Middletown
York Haven
Harrisburg
Allentown
Bethlehem
Easton
Phillipsburg
Stroudsburg
Scranton
Wilkes-Barre
Hazleton
Nanticoke
Sunbury
Milton
Muncy
Towanda
Montrose
Binghamton
Oneonta
Waverly
Sayre
Athens
Elmira
Corning
Hornell
Olean
Jamestown
Meadville
Titusville
Oil City
Franklin
Kinzua
Warren
Bradford
Du Bois
Clearfield
Philipsburg
Punxsutawney
Kittanning
Indiana
Ebensburg
Johnstown
Altoona
Lewistown
Williamsport

On July 2, 1950, the two areas were interconnected by a 29-mile long, 114 kv. line, capable of carrying only 60 thousand kw., due to restrictions in connecting lines. Each area can therefore depend on that amount only of reserve capacity from the other area in case of outage, and only that amount of economy energy can be interchanged between areas. Within this limit, central load dispatching has been done. The estimated net savings[1] are $150,000 per year.

Estimates of energy demand increases made by General Public Utilities after the outbreak of the Korean conflict indicated the need for substantial new generating capacity in the system. General Public Utilities maintained that construction plans which would further integrate the two areas would bring larger economies than could be obtained by the two areas as separate systems for three reasons: fuel costs, construction and generation costs per kwh. of new capacity, and maintenance and direct labor costs.

Due to nearness to mines, coal is about 40 per cent cheaper in the western than the eastern area. Thus, General Public Utilities' plan to build all new capacity (two 125,000 kw. generators) in one plant at Shawville, in Pennsylvania

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available in the interconnection would be placed in operation as the load increased. Savings were split equally between the system supplying and that receiving energy.

[1] Net of annual capital costs and repair of the interconnection.

Electric's territory, with a 220 kv. line connecting the eastern area, would mean a fuel bill lower by an estimated $1,130,000 per year (taking into account line losses) than it would be with one generator of the same size in each territory.

The system also argued that allowing the two areas to remain under common control would mean larger generators, with attendant lower costs per generated kwh. of fuel and lower construction costs per kw. of capacity. If the two areas were to be separated, General Public Utilities claimed that it would be necessary to install 66,000 kw. generators for Pennsylvania Electric and 75,000 kw. generators for the eastern group. Assuming the installation of four 66,000 kw. generators at one station instead of two 125,000 kw. units,[1] the estimated increased construction cost was $33.00 per kw., or a total of $8,250,000. If two 66,000 generators in each of two stations were assumed, the estimated increased construction cost was $42.00 per kw., or a total of $10,500,000. On the system's assumption of a 12 per cent rate for annual depreciation and capital cost, the first example of the use of smaller generators would increase costs an estimated $990,000 annually, and the second, $1,260,000 annually.

As pointed out in Chapter II, the fuel savings arise from the fact that a larger generator, other things being equal,

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[1] This, of course, would not be done.

will have a better heat rate; that is, more kwh. of energy obtained per pound of coal burned. It was stated that 66,000 kw. generators would have a heat rate of 10,810 btu. per kwh. of net generation, while 125,000 kw. units would have one of 9,638. The estimated savings in fuel costs in Pennsylvania Electric territory, for two 125,000 kw. units, compared with an equivalent amount of generating capacity of 66,000 kw. units, would be $430,000 annually. Dollar savings would, of course, be higher in the eastern area because of higher coal costs.

Labor and maintenance costs were estimated at $685,000 per year less in a two-125,000 kw. unit plant, as compared with two two-66,000 kw. unit plants. How this figure was arrived at is not stated.

Offsetting any savings would be the increased cost for the transmission line. General Public Utilities assigned only the cost of the 53 miles of line to be built between Lewistown to Middletown. The cost of this segment was estimated at $3,300,000. On the assumption that a 15 per cent rate was appropriate to cover operation, maintenance, depreciation and capital costs--and the Commission did not question this figure--the annual cost would be $495,000.

A glance at the map will show that the above segment of transmission line is only about one-third of the total line proposed to be built. General Public Utilities argued that the rest of the line would have to be built in any event.

Pennsylvania Electric would need the line from Shawville to Lewistown for the purpose of "getting power out of a Shawville plant of 250,000 kw. or more capacity," and the addition of a third 75,000 kw. unit at the Reading plant would require Metropolitan Edison to build a new connection with Middletown and east to the 220 kv. line of the Interconnection. The Commission did not question this conclusion.

The Commission felt that the economies to be realized from using larger generators was overstated, because it felt that units as small as 66,000 kw. would not be used by either area, if independent. The savings attributed to maintenance and direct labor seemed to be ignored in the decision. Basing its conclusion entirely on savings in coal costs over increases in cost due to interconnection, the Commission held that the properties met the requirements of Section 2 (a) (29) (A)--that is, that they constituted an integrated system--and therefore General Public Utilities' system met the requirements of Section 11 (b) (1).

Analysis

There could have been no loss of plant economies due to Commission divestiture orders, since, with the exception of the Florida-Georgia group of companies, none of those ordered divested were interconnected with any other company in the system, and this group remained intact.[1]

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[1] In the process of reorganization, Florida Public Service Company was merged into Florida Power Corporation, and Georgia Power and Light Company became a wholly owned subsidiary of Florida Power. Holding Company Act Release 5950.

Since the Commission did not order the separation of Northern Pennsylvania and New York State, any losses of plant economies resulting from such separation can hardly have been caused by the Commission's orders. It was willing to allow Northern Pennsylvania to be retained by New York State, and approved separation only upon General Public Utilities' insistence. The reasons for General Public Utilities' decision to separate the two are not clear, but the decision itself does not make sense, economically. Technically, Northern Pennsylvania is simply part of the distribution system of New York State, and the discussion of plant economies in Chapter II demonstrates how uneconomic it would be for the small Pennsylvania company to attempt to operate independently. The Commission's approval, on the grounds that it should not overrule management's judgment in this instance, seems weak. That is precisely what the Act empowers the Commission to do. It should be noted that the Commission got out from under this decision by ordering General Public Utilities to dispose of Northern Pennsylvania. The result would seem to be that Northern Pennsylvania either will be acquired by New York State (the only logical buyer) or will remain technically independent, but will be operated (as now) actually as a division of New York State. In any event, there can be no operating losses until expiration of the power contract between the two companies in 1955.

The trading of properties between Associated Gas and

Electric and United Gas Improvement Company has undoubtedly resulted in plant economies to the operating companies involved. This is especially true of the merger of the companies operating in Erie, Pennsylvania, because of the elimination of duplicate facilities.

Increased plant economies should also accrue to those former subsidiaries acquired by other systems, both public and private.

As far as losses of firm economies to Northern Pennsylvania are concerned, the Commission evidently thought that the severance study made by General Public Utilities was essentially correct; at least, it did not question it. Instead, other cases, all with estimated losses more than twice as great (in terms of percentages of gross revenues), were cited in which the Commission did not find the requirements of clause (A), concerning loss of "substantial" economies, to be met.[1] On this basis, it concluded that an increase of 1.44 per cent of gross electric operating revenues did not meet the requirements of clause (A). Concerning this point, it should be noted first of all that had Northern Pennsylvania been retained with New York State (or if New York State acquired Northern Pennsylvania), there should have been no

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[1] Why the Commission cited only cases involving the separation of gas properties from electric companies is not known. As this chapter will show, there have been a number of cases where electric properties were ordered separated even though percentage losses were estimated to be about as high.

increase in "operating expenses." New York State would have continued to supply services to Northern Pennsylvania, and, since the former company is roughly the same size as Metropolitan Edison, it should have been able to provide the services rendered by that company to Northern Pennsylvania, at about the same cost. Since the record does not show that the holding company itself provided any services to Northern Pennsylvania, these are the only places where there could be increase in operating expenses.

Apart from this, it is far from clear that there would be as much loss as was claimed. It is inconceivable that "depreciation" increases when an operating utility becomes independent. This could be caused only by unusual accounting practices, to say the least.

The question of equity capital costs will be of little significance if New York State acquires Northern Pennsylvania; in any event, if the operating ties between the two companies are not severed, and hence Northern Pennsylvania does not have to build its own generating units, little, if any, new equity capital will be needed.

Except in the case of Northern Pennsylvania, there is nothing in the record to indicate loss of firm economies to the divested companies. However, this does not necessarily mean that there were none. Therefore, as is done for each system analyzed in this and the next chapter, a study is made of the account, "administrative and general expenses," for

each company for which data are available. Briefly, this account includes executive and general office employees' salaries and expenses, management and supervision expenses, legal and regulatory commission expenses, and other such items. The data for this and all other such tables in the next two chapters are from Statistics of Electric Utilities of the United States, published by the United States Federal Power Commission annually since 1938. As explained at the end of Chapter II, the procedure is to compare, as between all companies and divested companies, the average relationships of the administrative and general expense account to gross electric operating revenues for the periods before and after divestiture. This comparison shows the effects of divestiture on the firm costs of the affected company.

The figures for the divested subsidiaries of Associated Gas and Electric Corporation are as follows. The average for Florida Power Company before separation is 6.5 per cent and after separation 4.4 per cent, a decline of 32 per cent. For Georgia Power and Light Company, the averages are 7.9 per cent and 4.1 per cent, a decline of 48 per cent. Paul Smith's Electric Light and Power Company shows a decline of 25 per cent, the averages being 12.1 per cent and 9.1 per cent, respectively. Tide Water Power Company also shows a decline of 25 per cent, with an average of 7.3 per cent before separation and 5.5 per cent as an independent.

TABLE 2

DIVESTED SUBSIDIARIES OF ASSOCIATED GAS AND ELECTRIC CORPORATION
Administrative and General Expenses (Less the Pension Account) as a Percentage of Gross Electric Operating Revenue

Year	Florida Power Co. (Including Florida Public Service Co. Merged 31 Dec. 1943)	Georgia Power & Light Co.	Paul Smith's Electric Light & Power Co.	Tidewater Power Co.	South Carolina Electric & Gas Co.
1938	11.0	12.8	17.1	11.5	9.5
1939	7.9	12.6	13.4	9.6	6.7
1940	6.8	6.9	9.7	7.5	4.5
1941	5.2	5.9	10.4	6.1	3.2
1942	6.0	6.3	11.3	4.9	3.9
1943	4.5	5.5	10.9	4.2	4.7
1944	4.2	5.6	10.5[a]	4.5[a]	5.0
1945	4.6[a]	5.9[a]	9.1	5.0	4.5
1946	5.5	5.2	10.2	5.6	5.7[a]
1947	4.9	5.3	10.8	5.6	5.1
1948	3.8	3.8	8.1	5.3	5.1
1949	4.2	3.8	7.9	6.2	6.2
1950	3.8	2.5	8.4	5.3	5.1[b]

[a] Year divested.

[b] Acquired South Carolina Power 31 March 1950.

South Carolina Electric and Gas Company shows an increase of 2 per cent, the average as a subsidiary being 5.1 per cent, and as an independent, 5.2 per cent. Compared with averages of substantially all electric companies in the United States for averages of the same years (see Appendix), the first four companies show declines substantially greater than for the average of all companies, while South Carolina Electric and Gas Company shows a lesser decline than the national average. In so far as this measure is meaningful for one system, the data do not show losses of firm economies.

One last comment on the decision to allow the Pennsylvania-New Jersey properties to be retained as a unit by General Public Utilities seems called for. It is apparent from the above discussion that an independent Pennsylvania Electric Company would not, in fact, build so much new capacity at Shawville, and hence would not need so much (if any) new carrying capacity to Lewistown. Thus, at least part of the cost of this connection, which is at least as long as the Lewistown-Middletown segment (see map, p. 55), should be added to the $3,300,000 cost of that segment as an offset to savings from the interconnection. On the other hand, it does not seem that the Commission should have ignored the economies to be obtained from larger generating units. While the companies, as independents, might not build units as small as 66,000 kw. it is doubtful that units as large as 125,000 kw. would be built. As pointed out in Chapter II, the smaller the service

area, the smaller the generators are likely to be, in order to minimize necessary reserve. With a very large unit compared to the load, an uneconomic amount of reserve capacity would be required. This savings tends to offset the increase suggested above. The Commission no doubt made the right decision, but it did not consider all the relevant costs in reaching that decision.

Cities Service Company

All the electric properties of Cities Service Company[1] were held by a subsidiary holding company, Cities Service Power and Light Company, and hence it is the decisions concerning the latter which are studied here. In 1940, the electric subsidiaries of Cities Service Power and Light served communities with an aggregate population of over 2 million in 14 states.[2] The consolidated book value was over 400 million dollars at the end of that year.[3]

The first Section 11 (b) (1) decision concerning this system was handed down August 17, 1943.[4] As can be seen on the map of this system, in addition to scattered properties, there were three clusterings of properties: the Ohio group, the

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[1] With the single exception of Ozark Utilities Company.

[2] Holding Company Act Release 1954.

[3] Holding Company Act Release 4489.

[4] Ibid.

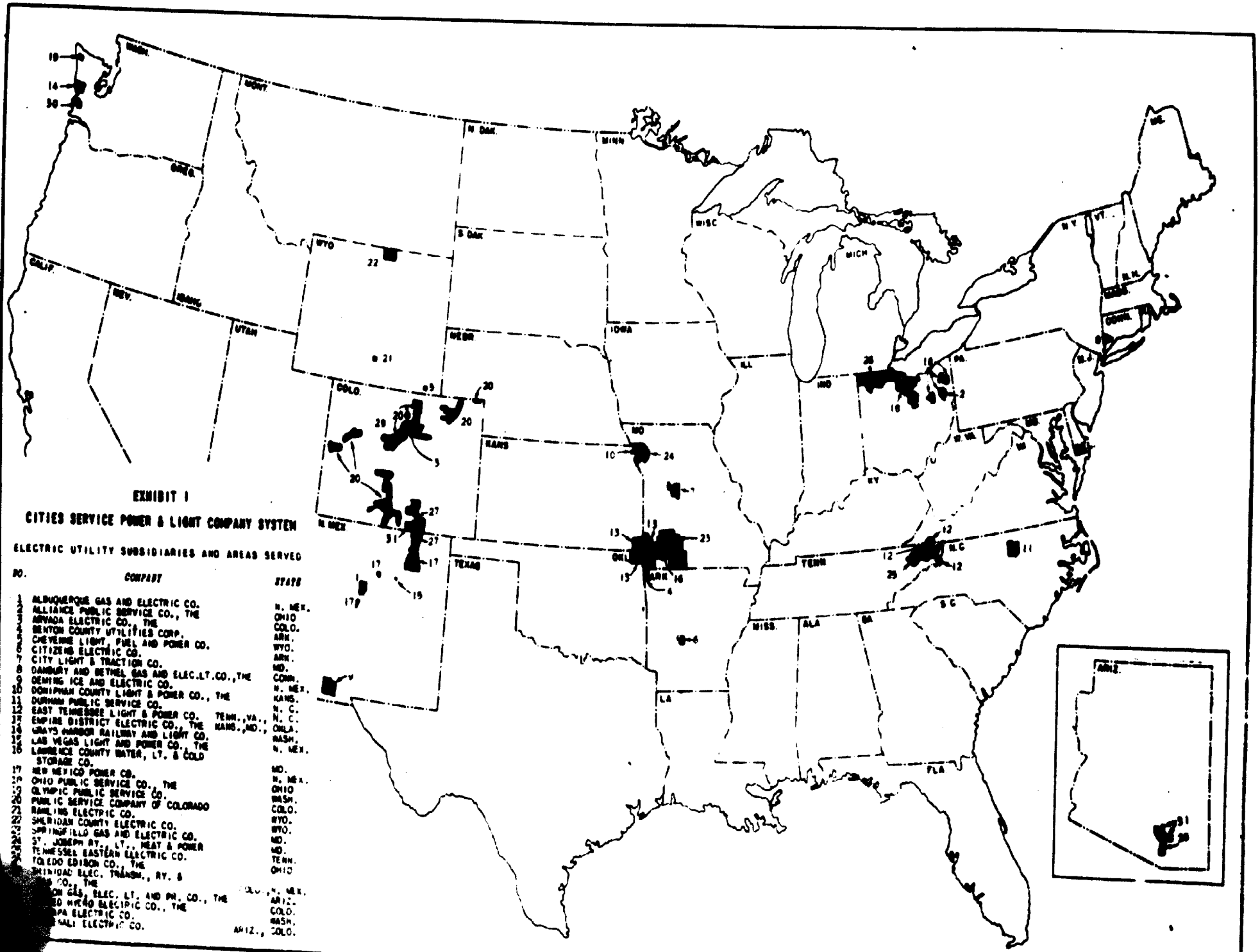

EXHIBIT I

CITIES SERVICE POWER & LIGHT COMPANY SYSTEM

ELECTRIC UTILITY SUBSIDIARIES AND AREAS SERVED

NO.	COMPANY	STATE
1	ALBUQUERQUE GAS AND ELECTRIC CO.	N. MEX.
2	ALLIANCE PUBLIC SERVICE CO., THE	OHIO
3	ARVADA ELECTRIC CO., THE	COLO.
4	BENTON COUNTY UTILITIES CORP.	ARK.
5	CHEYENNE LIGHT, FUEL AND POWER CO.	WYO.
6	CITIZENS ELECTRIC CO.	ARK.
7	CITY LIGHT & TRACTION CO.	MD.
8	DANBURY AND BETHEL GAS AND ELEC.LT.CO.,THE	CONN.
9	DEMING ICE AND ELECTRIC CO.	N. MEX.
10	DONIPHAN COUNTY LIGHT & POWER CO., THE	KANS.
11	DURHAM PUBLIC SERVICE CO.	N. C.
12	EAST TENNESSEE LIGHT & POWER CO.	TENN.,VA.,
13	EMPIRE DISTRICT ELECTRIC CO., THE	KANS.,MO.,
14	GRAYS HARBOR RAILWAY AND LIGHT CO.	OKLA.
15	LAS VEGAS LIGHT AND POWER CO., THE	WASH.
16	LAWRENCE COUNTY WATER, LT. & COLD STORAGE CO.	N. MEX.
17	NEW MEXICO POWER CO.	MO.
18	OHIO PUBLIC SERVICE CO., THE	N. MEX.
19	OLYMPIC PUBLIC SERVICE CO.	OHIO
20	PUBLIC SERVICE COMPANY OF COLORADO	WASH.
21	RAWLINS ELECTRIC CO.	COLO.
22	SHERIDAN COUNTY ELECTRIC CO.	WYO.
23	SPRINGFIELD GAS AND ELECTRIC CO.	WYO.
24	ST. JOSEPH RY., LT., HEAT & POWER	MO.
25	TENNESSEE EASTERN ELECTRIC CO.	MO.
26	TOLEDO EDISON CO., THE	TENN.
27	TRINIDAD ELEC. TRANSM., RY. & [illegible] CO., THE	OHIO
[illegible]	[illegible] GAS, ELEC. LT. AND PR. CO., THE	COLO., N. MEX.
[illegible]	[illegible] HYDRO ELECTRIC CO., THE	ARIZ.
[illegible]	[illegible]PA ELECTRIC CO.	COLO.
[illegible]	[illegible]ALI ELECTRIC CO.	WASH.
		ARIZ., COLO.

Rocky Mountain group, and what was called the mid-continent group.

The Company admitted the scattered properties were not retainable under the Act. It refused to indicate which of the three major groups it wished to retain as its major system. The Commission determined, in this instance, what properties it felt were a retainable system in each of the three areas.[1]

The Ohio properties consisted of three electric companies. At the end of 1939, the book value of their net property was 110 million dollars, with gross operating revenue for that year of 22 3/4 million dollars. As can be seen on the map, the companies served three non-contiguous areas, but they were all tied together with a 225-mile 132 kv. transmission line, which linked the two main generating plants in the system, one of which was in Toledo and the other east of Cleveland. On the basis of evidence presented, the Commission determined that, "there is interchange of energy and joint planning as to generation and transmission of energy and the use and erection of facilities." The Commission held that these electric properties were a single integrated public utility system within the meaning of Section 2 (a) (29) (A).

The mid-continent properties clustered in southwest

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[1] Only one of these could be retained by Cities Service as such. The integrated systems in the other two areas could, of course, be parts of holding company systems independent of Cities Service.

Missouri, extending into Kansas, Oklahoma, and Arkansas. In addition, there were two non-contiguous areas in Missouri, one about 100 miles north of the main body of properties, centering around Sedalia, and the other about 100 miles northwest of there, in St. Joseph and environs. In 1939 the total gross operating revenue of the companies was over 9 million dollars.[1] The net plant at the end of that year totaled nearly 45 million dollars.

The entire main area was interconnected and operated as a unit, with Joplin as the major energy source. The Sedalia property, while not adjacent to the main area, was interconnected by a company-owned transmission line, and the Joplin generating plant supplied about 95 per cent of its energy requirements. Its physical operation was coordinated with that of the main service area. The Commission held that these properties together met the requirements of the Act.

The Company claimed the St. Joseph properties[2] were also part of the above single system because they were capable of interconnection. It was stated that, because of load growth, new capacity would soon be needed in St. Joseph, and that it would be more economical to tie in to the Joplin

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[1] This includes revenue from gas, water and transport services as well as electricity. No separate data are available.

[2] St. Joseph Railway, Light, Heat and Power Company and Doniphan County Light and Power Company (Kansas).

generators than to build capacity in St. Joseph itself. It was also said that a line between St. Joseph and Sedalia would provide more economical power for Sedalia, which was currently at the end of the transmission line from Joplin.[1] No figures were given as to savings in production costs and costs of building the connection.

Even accepting this, the Commission did not find that St. Joseph was part of the main system. St. Joseph was much closer to non-system companies than to the main area, and the interconnecting transmission line would have to cross extensive foreign service areas.[2] The testimony indicated to the Commission that whether or not the connection would be made depended to a great extent on whether the properties remained under system control. It concluded that accident of ownership rather than regard for "actually contemplated benefits" was behind the proposal. The possibility had existed for many years, but the connection had not been made and no steps had been taken toward it. "This record contains estimates--made, apparently, to prove a point in litigation, and not in connection with a definite plan looking toward

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[1] Presumably, this was because of the spreading of fixed generator and transmission costs over more units, although variable generating costs might increase because of less efficient units being brought into use. The question of reserve capacity was not raised.

[2] This latter point is of course true of the Sedalia property also.

actual achievement," was the Commission's conclusion.

If not a part of the main system, could the property be kept as an additional system under the "ABC" provisions? If St. Joseph were to supply independently the services received from the Power and Light system service company, it was estimated that "administrative and general expenses" would increase $76,865 annually. What particular items accounted for this is not given, except that it included a 35 per cent increase in salary of the president and general manager. The Commission found it difficult to accept these particular increases or the reasons behind them.[1] Furthermore, since it was not then known how the service company would survive, if at all, the Commission found the estimate "meaningless." But even if the estimate of increased expenses were to be accepted, they amounted to only 2.67 per cent of the average gross operating revenue of the years 1939-1940, and it was said that this increase should be offset by the cost of maintaining a holding company system,[2] and "the hazard of having operating policies dominated by persons whose interest is not that of any particular company or service area, but the most profitable operation of a vast system."

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[1] For a more detailed discussion of this point, see below, pp. 87-88.

[2] The Commission said this cost was "significant, though sometimes difficult of isolation." See chap. ii for a discussion of the magnitude of this cost.

Economies lost to warrant retention under clause (A) must be "substantial." Taking into account the above factors, the Commission could not find "important operating economies" would be lost to St. Joseph by separation from the system. It was ordered divested.

The Rocky Mountain properties stretched from Sheridan, Wyoming, to Tucson, New Mexico, a distance of over 900 miles, with the major properties clustering in Colorado and north-central New Mexico. Substantial portions of the system were physically isolated, and in several instances where there was interconnection, it was through lines not owned or controlled by the system. These utility properties showed a total gross operating revenue in 1939 of about 23 million dollars, and at the end of that year had a combined net property per books of 98 1/2 million dollars.

Public Service Company of Colorado was by far the largest subsidiary in this area, contributing about two-thirds of the gross operating revenue figure and owning seven-tenths of the combined net property. Operationally, it was divided into two separate divisions: the northern division, running east and west in the northern part of the state; and the Salida-Alamosa division, extending south from Salida, Colorado, to the New Mexico border. While the service territories of the northern division were not contiguous, they were completely interconnected[1] and operated as a coordinated physical unit,

[1] Except for two very small distribution properties at

together with the Cheyenne Light, Fuel and Power Company. This latter property's service area was 30 miles at its nearest point to Public Service territory, and was connected to the system by a transmission line owned by the United States Bureau of Reclamation. However, arrangements with the Bureau called for power flow from Public Service to Cheyenne when the Bureau's hydro power flow could not meet the latter company's needs, and flow into Public Service when there was more than enough hydro power to serve Cheyenne. Thus, although not owned by the system, the line served as an important tie within it, making for the complete use of very low cost power whenever available.

The Salida-Alamosa division also was operated as a coordinated unit. It had its own hydro and steam generators and interconnected transmission and distribution lines, the same as the northern division. The two divisions were not interconnected and were operated separately.

The Commission found each division to be a single integrated electric utility system (including the Cheyenne property in the northern division). In order to find that they were both part of a single system, it had to be shown that they met the requirements of Section 2 (a) (29) (A)

Sedgewick and Ovid, Colorado, which were served entirely from non-affiliated sources. It was not shown that they could be economically operated as a part of the Public Service system, and hence they were ordered divested.

concerning capability of interconnection and operation as a coordinated whole. Concerning this point, it was testified that load growth forecasts indicated that by 1945 (two years later) Salida-Alamosa's load would equal its capacity without stand-by considerations. There were two feasible proposals on how to increase its energy supply: by interconnection with the northern divisions, and/or by interconnection with the Trinidad-New Mexico properties of the system. Actually, it was proposed to make both interconnections.

Trinidad had considerable excess capacity in its low cost fuel generating units as Walsenburg, since load had not grown in this company's territory as had been anticipated when the plant was built. Part of the benefit to be achieved by interconnection was expected to be the removal of the relatively high cost, inefficient plant at Alamosa from load carrying, and the relegation of it to stand-by in the system, but this would only be possible if the Trinidad interconnection were made, since Public Service did not have enough excess capacity to make this possible. Projected load flows made by the system as to what might be normally anticipated if the two connections were made, showed that Salida-Alamosa would rely mainly on Trinidad for energy. It was estimated that seven times as much power would be furnished by Trinidad as would be furnished by Public Service. The Walsenburg plant would provide power at a cost of $.002/kwh. compared to a cost of $.00262/kwh. from Public Service. Since Salida-Alamosa

was closer to the Trinidad lines than to those of the northern division, it would cost less to interconnect to the former than to the latter; the estimates were $80,600 and $215,600, respectively, excluding necessary incidental charges.

On the basis of this evidence, the Commission concluded that these interconnections would result in two relatively efficient properties, each being connected to a weaker property between them and contributing to the load of that property (Salida-Alamosa), but with no operating relationship between the end properties. While neither the economic feasibility, nor the system's intention of carrying out the above program was questioned, it was not found that it would integrate the three parts as required by Section 2 (a) (29) (A). The Commission felt that the proposals would not result in that kind of "unitary, coordinated operation between the properties at either end of the chain...." which would be necessary to meet the requirements of the Act. Centralized control of power flow was not contemplated and did not seem possible, even though communication between the Public Service and Trinidad dispatchers, with respect to sharing the Salida-Slamosa load, would take place.[1] Therefore, the Commission felt that the Salida-Alamosa division should be considered a part of the Trinidad-New Mexico-Las Vegas-Albuquerque properties,

[1] "It is not shown that the routing and central allocation of power, as between the properties of Public Service and Trinidad, will be possible or attempted."

and that there would be loss of economies in separating the two divisions:

> Although benefits are to be expected from the connection between the main body of Public Service properties and those of the Salida-Alamosa division, we do not believe that an interconnection would create such interdependence between .... [the two sets of properties] as to necessitate common control, nor do we believe that their separation from common control will materially affect the benefits to be achieved by interconnection. The value of the proposed interconnection has been strenuously urged. If the claims of the respondents are to be taken as valid, then .... [it] would commend itself as feasible, even if the two groups of properties were separated from common control.

However, the Commission stated that it did not have the power to order the inclusion of Salida-Alamosa with the Trinidad-New Mexico system.[1] Therefore, it was ordered that Salida-Alamosa might be retained as a part of the integrated system either of Public Service or of Trinidad. The system was to decide that question. However, the Public Service and Trinidad properties could not be part of the same integrated system.

Although legally two separate companies, the Trinidad property and the New Mexico Power Company were operated as a unit, with central load dispatching and energy interchange between the Walsenburg, Colorado, and Dawson, New Mexico, generating plants. They were found to be a single integrated system. The Las Vegas Light and Power Company lay 40 miles southwest of the terminus of the Trinidad-New Mexico line.

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[1] Economies could be obtained by including it with either group.

It was entirely self-contained physically, with its own small (1,760 kw.) generating plant serving about 2,000 customers. The Albuquerque Gas and Electric Company, serving four cities and adjacent rural areas, was an interconnected system starting about 50 miles southwest of Las Vegas and extending for about 90 miles. Each of the cities had a generating plant, but the Albuquerque plant had the major capacity to bear the group load.

Cities Service introduced evidence to show that it would be economically desirable to interconnect the three sets of properties, that is, Trinidad-New Mexico, Las Vegas, and Albuquerque. Such interconnection would require a 93-mile, 69 kv. transmission line from the southern end of the Trinidad-New Mexico property to the northern end of the Albuquerque group, via Las Vegas. The cost was estimated at $465,000, including extensive repair of existing lines to carry the higher voltage. Due to lower fuel costs at the Dawson plant than elsewhere in New Mexico properties, ".... savings in operation would be affected, yielding a return on the investment of $59,269 per annum."[1] Although there were apparently no plans to build this interconnection in the near future, the Commission felt that the "capability" requirements of Section 2 (a) (29) (A)

[1] Presumably, this means cost reductions in generation expenses per year offsetting by this amount the annual costs of the interconnection. Probably it does not include evaluation of deferring the cost of building new capacity at Las Vegas and Albuquerque.

were met, and hence held that the Trinidad-New Mexico, Las Vegas, and Albuquerque properties were all part of one integrated system. Of course, at the option of the system, the Salida-Alamosa division of Public Service might be added to this group. As noted above, the Commission felt this would be most desirable, in view of the evidence. With low-cost generators--Walsenburg and Dawson--in the center, serving higher generating-cost properties on either end, this would form what was called a natural operating loop.

The other four properties in the Rocky Mountain area were located in Sheridan and Rawlins, Wyoming, and in Tucson and Deming, New Mexico. None of the four was connected with any other property in the system. In all cases, intervening stretches of mountainous and sparsely settled country separated them from the main operating clusters. The Commission found no evidence, either in existing or proposed physical interconnection and methods of operation, or in the techniques of the industry, that there would ever be the kind of unitary, economic operation necessary to meet the requirements of the Act. Furthermore, the Commission felt that they could not meet the geographic requirements of Section 2 (a) (29) (A). Therefore, the only question was whether any of them might be retained as addition systems under the "ABC" standards with any of the main systems already discussed.

The Rawlins Electric Company was the smallest of the four properties, with gross operating revenue in 1939 of about

$138,000, and net plant per books, at the end of that year, of about $400,000. It was estimated that if the company were operated as an independent, the annual increase in general and administrative expense would be $7,600 annually, or 5 per cent of the average of gross operating revenue for the years 1939-1940. The increase was based on a 50 per cent increase in the president's salary and "substantial" increases in the salaries of management and operational personnel.[1]

As it always has, the Commission found it "difficult to accept" estimates of increases in management's wages due to independence. It said that the estimates were made "without apparent relation to other reported data, and are subject to substantial revision." Although small, the company was not shown to be incapable of independent operation, in the Commission's opinion. The property was ordered divested.

Similarly, it was felt that no adequate showing of the loss of substantial economies had been made with regard to the Sheridan property. It was claimed that separation would increase operating expenses by 7 per cent annually. The Commission said:

> We disagree; even accepting the basis of calculation, we arrive at a 5.4% increase, and some of its elements are questionable.

No information is available on how the figures were arrived

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[1] These are the only increases mentioned, but it is apparent that little else could be included in the $7,600 figure.

at. In addition to not meeting the "A" requirements, such combination would not meet the "C" requirements, in the Commission's opinion.

A decision on whether the Tucson and Demming properties were retainable as additional systems was postponed in this Release in order for additional evidence to be presented as to whether the possibility of connecting Tucson and Demming would so relate the two as to make them together a single system. This whole question was resolved on March 30, 1944.[1]

The first issue in this decision was whether the Tucson and Demming properties were parts of the Trinidad-New Mexico-Las Vegas-Albuquerque properties, already determined to be an integrated system. It was argued that they met the "capability" requirements of the Act on the basis of plans made by the United States Bureau of Reclamation. As may be seen on the map of this area, Tucson is about 200 miles west of Demming, which city is about the same distance from the (then) nearest system line, and 125 miles from the Elephant Butte hydro plant (owned by United States Bureau of Reclamation), with which it was interconnected and from which it got about 85 per cent of its energy.[2] The Bureau contemplated transmission lines between Tucson and Demming, and from Elephant Butte to Albuquerque, upon the completion of Davis

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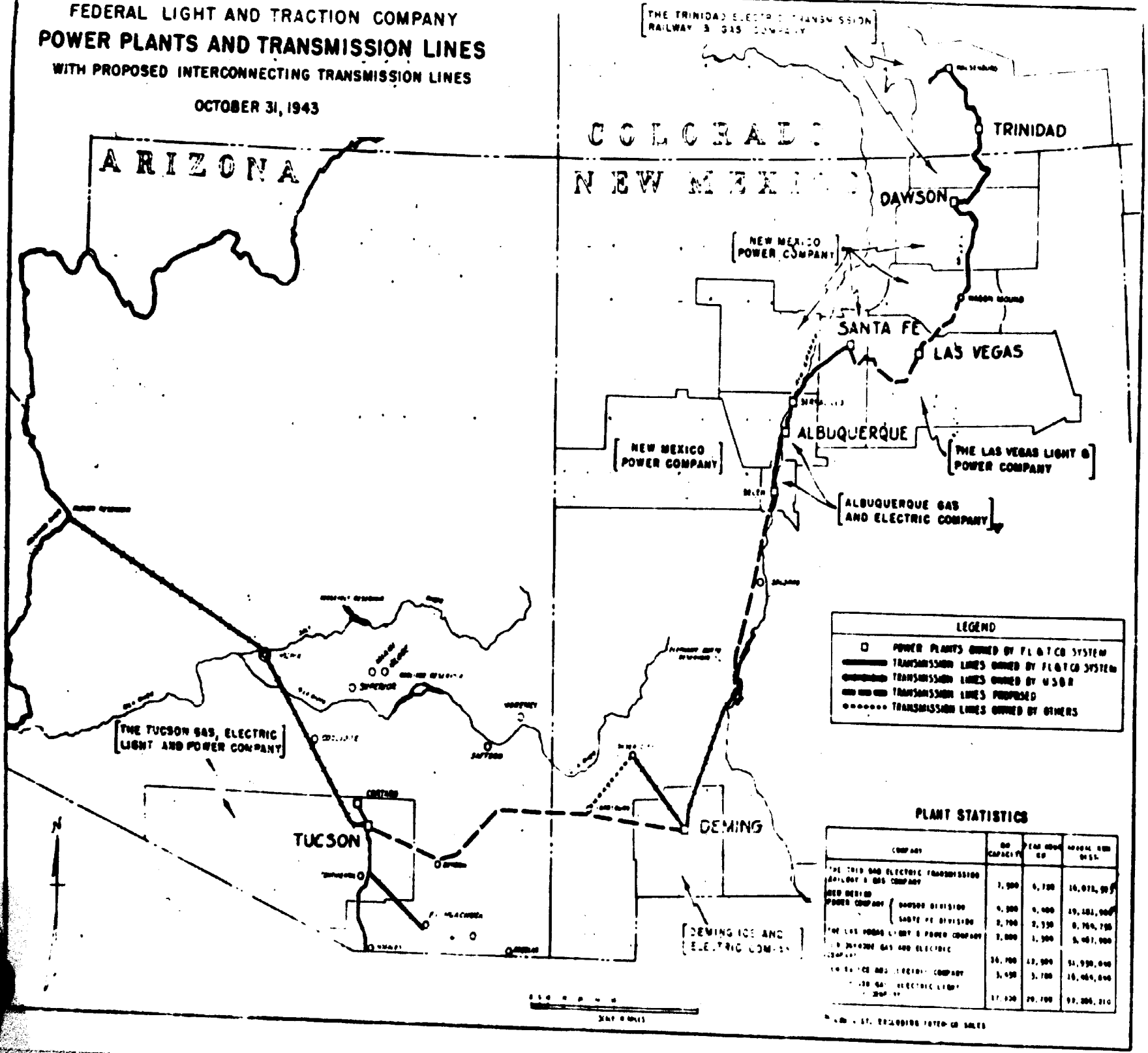
[1] Holding Company Act Release 4960.

[2] It obtained the rest from its own generator.


FEDERAL LIGHT AND TRACTION COMPANY
POWER PLANTS AND TRANSMISSION LINES
WITH PROPOSED INTERCONNECTING TRANSMISSION LINES
OCTOBER 31, 1943
ARIZONA
COLORADO
NEW MEXICO
TRINIDAD
DAWSON
NEW MEXICO POWER COMPANY
SANTA FE
LAS VEGAS
ALBUQUERQUE
NEW MEXICO POWER COMPANY
THE LAS VEGAS LIGHT & POWER COMPANY
ALBUQUERQUE GAS AND ELECTRIC COMPANY
THE TUCSON GAS, ELECTRIC LIGHT AND POWER COMPANY
TUCSON
DEMING
DEMING ICE AND ELECTRIC COMPANY
LEGEND
POWER PLANTS OWNED BY FL&TCO SYSTEM
TRANSMISSION LINES OWNED BY FL&TCO SYSTEM
TRANSMISSION LINES OWNED BY USBR
TRANSMISSION LINES PROPOSED
TRANSMISSION LINES OWNED BY OTHERS
PLANT STATISTICS

Dam, on the Colorado River, work on which had been stopped due to the war. The lines were to be built (presumably) to find markets for the hydro power to be generated as a sort of by-product of the water utilization project at Davis. The Commission pointed out that such interconnection would not mean that the properties would or could be operated as a unified group. Estimates showed that, out of a total of a 400,000 kw. load in the proposed system, 334,000 kw. of firm power were to be contracted for with the United States Bureau of Reclamation upon the completion of the project. Thus, there could be relatively little interchange between system generators and system markets. Furthermore, the Bureau's standard policy was to refuse to permit its lines to be used for wholly private interchange. In view of this, the relaying of power back and forth between load centers in order to obtain lowest cost generator use in the proposed system could hardly be contemplated as normal procedure, as the Act requires. The result would not be coordination of the properties; rather, there would be an additional source of outside power serving the properties.

There was some testimony to the effect that the system was contemplating building the interconnection itself. The Commission considered it difficult to envision such a program without taking into account the availability of United States Bureau of Reclamation surplus hydro power. If such power were available, system lines should be built only if the

benefits of owning the lines outweighted the benefits of having the Bureau build and own them. It did not appear to the Commission to be economical, "in the light of these factors," for the system to interconnect itself. Thus, the "capability" requirement was not considered met.

The remaining question was whether either Demming or Tucson might be retained as added systems under the "ABC" requirements. It was argued that both plant and firm economies would be lost if they were separated from the system. However, the Commission could not find evidence of loss of plant economies. The Bureau's proposals would not be affected by accident of ownership of facilities. Its policy is to deal with each purchase point as a separate customer, notwithstanding joint ownership of those points. The Commission, therefore, did not find that joint ownership had been shown relevant to obtaining the plant economies which would result from the proposed interconnection.

> We have noted that the feasibility of these interconnections depends upon the availability of United States Bureau of Reclamation surplus hydro power and that, should such power be available, system-owned lines would hardly be feasible in view of the proposals of the United States Bureau of Reclamation to construct these lines.

The Commission did not think that clause (A) pertained to economies which could be secured without the continued retention of control.

Concerning the loss of firm economies, it was estimated that had Tucson not been included in the consolidated tax return

of the system, its corporate income tax would have been about $120,000 more in 1942. It was also said that the company's administrative and general expenses would have been about $66,000 higher, because the cost of "supervisory personnel" would have to be increased an estimated $10,000 annually, along with cost increases due to hiring a local auditor, purchasing agent, budget and tax man, added clerks and stenographers, and the increased cost of purchasing, "etc." Evidence was also introduced to show that, in terms of ratios of administrative and general expenses to operating revenue, both Tucson and Demming were more efficiently operated than comparable independent electric companies. The purpose of this evidently was to show that, at least in this case, holding company control gave more efficient and cheaper management than did independent control. The Commission questioned the relevance of this data. It said that the argument should be made to Congress ".... which has already indicated its policy on the question of the over-all merits of holding companies."

As always, the Commission held corporate income tax savings not to be an economy within the meaning of the Act. While it did not question the wisdom of businessmen's attempts to minimize taxes, it felt that operating companies which showed in no other connection the necessity of joint control for efficient, economical operation, could not be retained simply to lower current tax obligations. Tax payments might be lowered, under the consolidated tax provisions of the law,

by companies jointly owned, but otherwise entirely unrelated. The Commission decided that the increase in administrative and general expenses was not "substantial" within the meaning of the Act. It should be noted that the $66,000 estimated increase amounted to about 2.4 per cent of 1943 gross operating revenues of Tucson. In addition, it was felt that the requirements of clause (C) were not met. Tucson was ordered divested.

The same was not true of Demming. Although no data were contained in the decision, the Commission said:

> Although we have considerable question about the accuracy and relevance of much of the evidence adduced to show that a separation of Demming from the remainder of the system properties would result in the loss of substantial economies, nevertheless considerable expenses may be incurred and considerable aid resulting from the present affiliation lost. This is the type of company whose retention together with stronger operation properties we believe to be within the meaning of the Act.

Demming was ordered retainable as an additional system to the already-determined integrated system of Trinidad-New Mexico-Las Vegas-Albuquerque.

In this connection, it is interesting to note the comparative sizes of the properties involved. In 1943 the net plant per books of the New Mexico-Las Vegas-Albuquerque properties was more than 13 million dollars, with gross operating revenue during that year of 4 million dollars. Comparable figures for Tucson were more than 7 million dollars and 3/4 million dollars, and for Demming, 2/3 million dollars and 1/3 million dollars.

Additional information concerning the alleged loss

of economies due to separation from the holding company system was contained in the Section 11 (b) (1) decision on the gas properties of Cities Service.[1] It was argued that at least the mid-continent electric system met the "ABC" standards for an additional system to the main gas system, which was located in the same general area.[2] Testimony was introduced to show that if the mid-continent electric companies operated independently of Cities Service control, and were thus deprived of the services of that system's service company, the necessary additions to their staffs to perform the same functions themselves would result in an increase in annual costs of $71,000. This figure was 1.6 per cent of the 1941 combined gross electric operating revenue of this group. To employ Stone and Webster (an independent service company) to do the same job would result in "additional charges of $155,178 to the Mid-Continent electric group, over the charges presently being paid [the system service company]." The Commission decided that even if the figures were correct, they would not represent a "substantial" loss, but even so, it questioned their validity. To show why, it used as an example Public Service Company of Colorado, although that company was no

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[1] Holding Company Act Release 5028, May 5, 1944.

[2] The Ohio properties could not meet the geographic requirements of clause "B," and at least some of the Rocky Mountain properties had been disposed of, although the latter, at least, were included by Cities Service in its attempt to show loss of firm economies.

longer in the system.[1]

It was estimated that, as an independent, Public Service would have to double the president's salary (from $20,000 to $40,000 per year) and hire an executive vice president at $25,000. The reasoning behind this can best be shown by quoting the testimony:

> What we have attempted to do is to put in a top executive who will not be apart from the company, but who is not going to be bothered with [operating] problems, and where he can think abstractly of the problems in front of the company. The new executive vice-president, on the other hand, will be the active general manager who would be in direct charge of the operations of the company. We feel that such an organization would be absolutely essential to rendering good service.

The Commission was not impressed. It doubted that the separation from the system's service company would change Public Service so much that it would be necessary to hire a new man at a salary of $25,000 to perform the managerial duties previously done by the president as part of his job, while the president himself, at double his previous salary, performed the duties described above. The estimate included also (in addition to expanded clerical help and increased salaries for many other officers), new positions of a chief engineer, two assistant chief engineers, a comptroller, an assistant purchasing agent, an assistant treasurer, and a staff assistant, all of which were wholly new positions. The Commission felt

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[1] Why the mid-continent properties themselves were not used is not clear.

that the record did not bear out the claim that these additions were necessary to supplant the service company's services. It noted that in "many" important functions, the actual work was done by the staff of the operating companies, with the service company doing only supervision. In engineering, for example, the service company's department was "very small" and was "purely and simply a consulting service on more important problems," in the words of a witness. In a similar manner, the service company's auditing and accounting staff merely certified the operating companies' work and acted as a consultant on difficult matters. Thus, no change was made in any previous decision, and no electric property was retainable with the main gas system.

Cities Service decided to stay in the oil business and to dispose of all of its gas and electric properties.[1] As far as the electric properties are concerned, all were disposed of as operating companies. No holding company systems at all were maintained.

All the stock of Public Service Company of Colorado (including the Salida-Alamosa division) and its subsidiary, Cheyenne, was sold to the public in 1943.[2] The properties of New Mexico, Las Vegas, Albuquerque, and Demming were combined into one company--Public Service Company of New Mexico--

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[1] Holding Company Act Release 5350.

[2] Holding Company Act Release 5075.

the stock of which was sold to the general public.[1] The Trinidad property was not united with this system, even though it was permissible to do so, and was disposed of separately (after acquiring the Dawson division of New Mexico Power Company) to investment banking interests in December, 1945.[2] The properties at Rawlins and Sheriden, Wyoming, were sold to individuals[3] and the stock of the Tucson company was sold to the general public.[4]

In the mid-continent area, the St. Joseph property was acquired by a registered holding company.[5] The Sedalia property was acquired by the Missouri Public Service Company, a non-affiliated electric utility. The rest of this group, it will be remembered, was geographically contiguous. It was disposed of in two parts: the Springfield Gas and Electric Company was sold to the city in which it operated, and the remaining properties (including the Ozark Utilities Company, the only electric property in the Cities Service system not a subsidiary of Power and Light) were merged into the Empire

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[1] Holding Company Act Releases 4960, 6887, 8067, and 8113.

[2] Holding Company Act Release 6332.

[3] Holding Company Act Releases 4820 and 6059, respectively.

[4] Holding Company Act Releases 6654 and 6683.

[5] The United Light and Railway Company, see below, p. 278 ff.

District Electric Company, the stock of which was then sold publicly.[1] The stock of Toledo Edison was sold publicly in 1950.[2] The stock of Ohio Public Service Company (into which the third company, Alliance Public Service Company, had been merged in 1943) was sold to a former affiliate of Commonwealth and Southern.[3] Of the scattered properties, all small, two have been sold to large operating companies, one each to the TVA and a Washington power district, and the rest to individuals.[4]

Analysis

There could not have been any actual losses of plant economies due to Commission orders in the Cities Service system, since no properties which were interconnected were required to be separated. The Sedalia and Springfield properties, which were interconnected with other companies in the mid-continent group, were in fact separated, but this was entirely a decision of the management.[5] In the case of the Springfield company, at least, it is probable that the old

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[1] Holding Company Act Release 5286.

[2] Moody's Manual, 1951.

[3] See below, pp. 225 ff.

[4] Moody's Manual, 1951.

[5] This was also true of the Ohio properties. For a discussion of plant economies here, see below, pp. 229 ff.

operating relationship has been maintained. The city of Springfield, which acquired this property, already had a municipally owned distribution system to which Cities Service's mid-continent properties have been selling energy for 37 years. About the same amount of energy interchange between these other companies and the now combined Springfield properties takes place as before.[1]

The Sedalia property (City Light and Traction) was purchased by, and merged into, an adjacent operating company. Although no information is available, it does not appear likely that plant economies were lost by this company due to its transfer. And the scattered properties which were acquired by adjacent systems, both public and private, probably have gained plant economies.

It is possible, however, that future plant economies were lost due to separation of companies which might have been economically interconnected, as the system had argued. Not a great deal can be said about this, but a few salient facts should be noted. St. Joseph clearly gained plant economies upon separation, since it became operationally an integrated part of the adjacent system which acquired it.[2]

The Rocky Mountain properties present more of a puzzle. If interconnection between the Salida-Alamosa division

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[1] Moody's Manual, 1951.

[2] See below, pp. 278 ff.

and Trinidad was so desirable, why were the two not kept together as part of the southern integrated system? If plant economies could be gotten by interconnecting the two, even though separately owned, why are they still not physically connected? As a matter of fact, a tie between Salida-Alamosa and the main division of Public Service of Colorado is only just being completed, and no new generating capacity has been built in the former's area.[1] Clearly, the system's load growth estimate was erroneous.

There are two possible reasons for separating Trinidad from what is now Public Service Company of New Mexico. The first is, by so doing, the latter company confined its operations to one state and so is not under the jurisdiction of any Federal regulatory body. The second is that Trinidad, even though it does have low generating costs, does not seem to have a profitable future. At the time of sale, it was testified that the reason the price was so low was because the property served a one-industry area--coal--and there were no growth prospects.[2] Furthermore, although it has been noted previously that Trinidad had large excess capacity, total capacity at the time of sale, including the Dawson, New Mexico, generating plant (which previously had not been legally part of Trinidad, but with which it was interconnected

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[1] Moody's Manual, 1951.

[2] Holding Company Act Release 6332.

and operated as a unit) was only 14,000 kw.

The proposed interconnection through Las Vegas to the other parts of Public Service of New Mexico has not been built. Data for 1951 do not appear to bear out the system's earlier assertions concerning possible plant economies.

The bulk of anticipated losses were in the area of firm economies; specifically, in the administrative and general expense account. It will be remembered that the system anticipated increases equal to 1.6 per cent of 1941 gross operating revenues in the administrative and general expense accounts of the mid-continent companies upon their separation from the system service companies. In rebutting this, the Commission used the estimates of necessary salary increases for Public Service of Colorado upon separation, and concluded that these estimates were incorrect. The only estimates stated in the decision were the increases in salaries of the president and executive vice-president, a total of $45,000 annually. As a matter of fact, the Commission was correct. The system's estimates in this particular case were wrong. The independent Public Service of Colorado did not increase executive's salaries by this amount.

It will be noted that, although the property became independent in early 1944, the salaries of general officers and executives were only $16,000 higher in 1950 than in 1943, compared with the estimate of necessary increases of $45,000.[1]

[1] This account is, of course, less than it was in 1938,

TABLE 3

PUBLIC SERVICE COMPANY OF COLORADO

Year	Salaries of General Officers and Executives	Management and Supervision Fees and Expenses
1938	$60,175.00	$117,333.00
1939	46,372.00	53,867.00
1940	41,718.00	30,687.00
1941	32,928.00	16,782.00
1942	33,236.00	16,000.00
1943	33,261.00	4,382.00
1944	44,892.00	1,669.00
1945	48,172.00	
1946	45,348.00	
1947	48,501.00	
1948	49,357.00	
1949	50,530.00	
1950	49,114.00	

It should be noted that business increased greatly from 1943 to 1950, both in real and money volume; the gross electric operating revenues for the 2 years were 14 million dollars and 22.4 million dollars, respectively, and that no service company was used after 1944.

Tucson is the only other company for which data are available on specific items which the system estimated would be increased upon separation.[1] A $66,000 increase, mainly in

[1] Rawlins is too small to be included in the Federal Power Commission data and St. Joseph was acquired by another holding company system. There were no specific increases mentioned for any of the other companies; only general increases in the administrative and general expense total account.

salaries, was the expectation.[1] In view of the type of supervisory service rendered by the system holding company, the anticipated $10,000 increase (part of the above total) in "supervisory personnel" very likely would not show as a part of direct production cost, but would be included in the administrative and general expense account. Therefore, the following table, which includes specific items in that account, should show the effect of separation.

TABLE 4

TUCSON GAS, ELECTRIC LIGHT AND POWER COMPANY

Year	1 Salaries of General Officers & Executives	2 Other General Office Salaries	3 Management & Supervision Fees & Expenses	4 Total of Columns 1, 2 & 3	5 Gross Electric Operating Revenue	6 Column 4 as a Per Cent of Column 5
1938	$32,952	$18,414	--	$51,366	$1,275,000	4.0
1939	38,030	24,252	--	62,282	1,360,000	4.6
1940	34,687	25,230	--	59,917	1,410,000	4.2
1941	38,210	29,030	--	67,240	1,500,000	4.5
1942	13,542	11,656	$17,904	43,102	1,710,000	2.5
1943	13,777	13,430	17,785	44,992	2,000,000	2.2
1944	13,959	12,977	18,224	45,160	2,040,000	2.2
1945	14,144	12,949	17,553	44,646	2,010,000	2,2
1946	19,247	15,245	7,097	41,589	2,160,000	1.9
1947	26,688	17,650	--	44,338	2,550,000	1.7
1948	33,375	21,747	--	55,122	3,090,000	1.8
1949	42,693	24,490	--	67,183	3,470,000	1.9
1950	44,361	24,553	--	68,914	3,760,000	1.8

[1] With the exception of increased cost of purchasing and with the possible exception of the "etc.," all the increases were in personnel.

It is not possible to separate the effects of independence and of the increased dollar volume of business, but ignoring this latter factor (which should not be done), the data does not show anything like the estimated increase after 1945, the last full year of holding company control.

Taking into account the increased volume of business compared to the increases in salaries, a reduction appears after separation, although this, of course, may be in spite of separation instead of because of it. In any event, the data do not show that the anticipated losses actually occurred.

Firm costs, specifically, administrative and general expenses as a percentage of gross operating revenues, were expected to increase upon separation for a number of the subsidiaries, including the above two. The following table gives this information for those companies for which it is available.

TABLE 5

DIVESTED SUBSIDIARIES OF CITIES SERVICE
Administrative and General Expenses
(Excluding the Pension Account)
as a Percentage of Gross Electric
Operating Revenue

Year	Public Service of Colorado	St. Joseph	Tucson	Trinidad	Empire[a]	Danbury
1938	6.6	8.1	7.9	8.1	8.0	9.2
1939	6.3	8.9	7.2	9.4	8.5	8.1
1940	6.3	8.3	6.9	9.5	7.5	7.6
1941	5.4	8.0	6.4	7.7	5.9	7.9

TABLE 5 (Continued)

Year	Public Service of Colorado	St. Joseph	Tucson	Trinidad	Empire[a]	Danbury
1942	6.2	7.6	6.1	7.5	7.3	7.7
1943	5.3[c]	6.7	5.0	6.8	7.1	7.6
1944	5.4	6.3	4.7	7.2	7.0[c]	7.4[c]
1945	5.8	5.4[c]	5.2	6.6[b,c]	7.5	5.7
1946	5.7	5.5	6.9[c]	8.0	7.5	6.1
1947	6.4	5.7	5.5	8.6	6.7	6.1
1948	6.5	5.5	5.6	9.8	6.8	4.7
1949	6.3	5.4	5.0	6.8	7.3	4.6
1950	5.0	6.1	5.4	7.8	6.9	4.4

[a] On September 1, 1944, Ozark Utilities, Benton County Utilities and Lawrence County Light were merged into an Empire. Prior to 1944, data are available for Ozark alone of the three, and that for the years 1940-1943 only.

[b] Acquired certain properties of New Mexico Power Company, 31 December 1945.

[c] Year divested.

Averages of these percentages for the years before, and after, separation are as follows: Public Service of Colorado 6.2 per cent and 6.0 percent, an average decline of 3 per cent; St. Joseph (acquired by the United Light and Power system in 1945, became independent in 1950) 7.7 per cent and 5.6 per cent, an average decline of 27 per cent; Tucson 6.2 per cent and 5.4 per cent, an average decline of 13 per cent; Trinidad (now Frontier Power Company) 7.9 per cent and 8.2 per cent, an average increase of 4 per cent; Danbury (acquired by the Derby Gas and Electric Corporation, an operating company)

8.0 per cent and 5.3 per cent, an average decline of 34 per cent. The figures for Empire are included for purposes of comparison, but the data for the years following 1944 are not strictly comparable with those before. The inclusion of Ozark into the Empire data from 1940-1943 raises the average for each of these years about .3 per cent. Ozark was too small in 1938-1939 for data to be available, and the same is true of the other two companies for all the years prior to 1944. Therefore, the average for those years prior to 1944 is probably higher than the 7.4 per cent that the available data show. The average for the period since 1944 is 7.1 per cent. Thus, the average decline for St. Joseph, Tucson, Danbury (and probably Empire) declined more than the national average for those years, while the averages for Public Service and Trinidad declined less. On the basis of just this system, the available data do not seem to show loss of firm economies.

It must be remembered that the percentage increases cited above were supposed to occur when the various operating companies became independent. Some of them did not in fact become independent, but became subsidiaries of other companies. The important thing, as far as this study is concerned, is whether losses actually did occur.

Electric Bond and Share Company

Electric Bond and Share Company was the largest of the utility holding companies. As of December 31, 1930, the

combined book assets of its system totaled nearly 3.9 billion dollars.[1] As of December 31, 1940, consolidated assets were still nearly 3.5 billion dollars.[2] The utilities controlled were predominately electric, and in 1940, 32 states were served by the subsidiaries (see maps). Their service areas included nearly a tenth of the population of the United States. They generated more than 13 per cent of the total power generated in the United States in that year, more than 19 trillion kwh., and they received more than 300 million dollars in revenues.

Electric Bond and Share Company was originally formed by General Electric in order to sell electrical generating equipment.[3] At the time hearings began, it controlled 5 sub-holding companies, which in turn controlled 243 direct and indirect subsidiaries. The 5 were: American Gas and Electric Company, American Power and Light Company, Electric Power and Light Company, National Power and Light Company, and American and Foreign Power Company, Incorporated. The latter company controlled only foreign utilities and hence does not enter this analysis. For reasons which will appear below, American Gas and Electric Company will be considered separate of the other three.

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[1] Bonbright and Means, op. cit., p. 105.

[2] Holding Company Act Release 2962.

[3] For the history of the company, see Bonbright and Means, op. cit., pp. 98 ff.

American Gas and Electric Company

This company was the only one of the sub-holding companies which had what might be termed an actual separate corporate existence prior to 1935. It had its own service company, and none of its subsidiaries ever used any of the contract services offered by Electric Bond and Share's service company. Financial services only were rendered by Electric Bond and Share, and these were not under contract.[1]

The Commission's Section 11 (b) (1) decision on this company was handed down on December 26, 1945.[2] The subsidiaries were actually operated as 3 separate systems, the so-called Central system, the northern Pennsylvania system, and the New Jersey system (see map). At the end of 1944, the gross utility plant of the three systems totaled more than 1/2 billion dollars, divided as follows: Central system, 443 million dollars; northeast Pennsylvania system, 28 million dollars; New Jersey system, 46 million dollars. For that year, gross operating revenues were, respectively: 102 million dollars, 7 million dollars, and 11 million dollars, a total of about 120 million dollars.

By 1930, the Central system was substantially complete from a geographic standpoint, and all generating stations and

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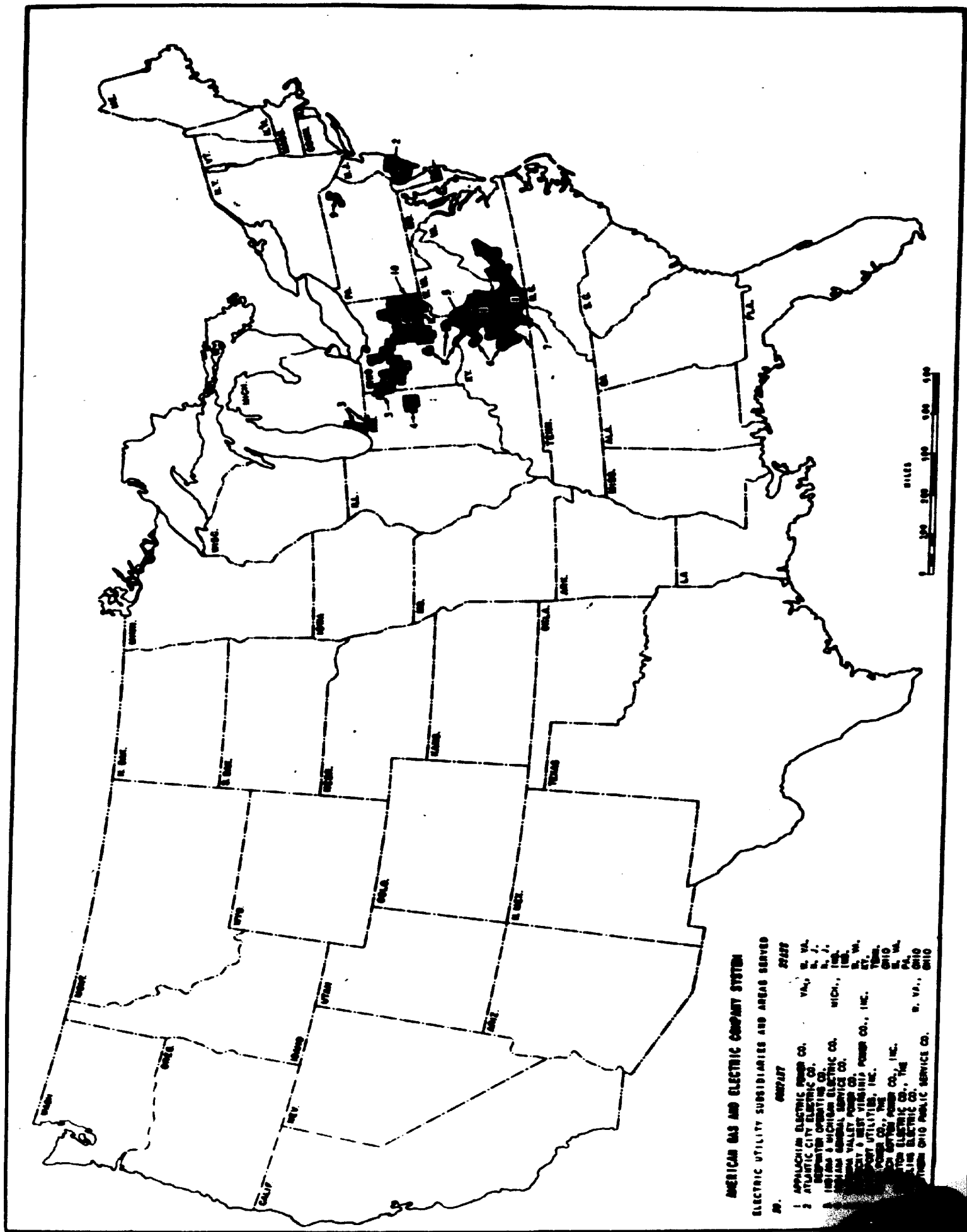
[1] "Power and Gas Holding and Operating Companies," United States Congress, Committee on Interstate and Foreign Commerce, 73rd Cong., 2nd Sess., H.R. 827, Part 3, p. 489, and Holding Company Act Release 2749.

[2] Holding Company Act Release 6333.


AMERICAN GAS AND ELECTRIC COMPANY SYSTEM
ELECTRIC UTILITY SUBSIDIARIES AND AREAS SERVED
NO.
COMPANY
STATE
1 APPALACHIAN ELECTRIC POWER CO. VA., W. VA.
2 ATLANTIC CITY ELECTRIC CO. N. J.
KENTUCKY OPERATING CO. KY.
INDIANA & MICHIGAN ELECTRIC CO. MICH., IND.
INDIANA GENERAL SERVICE CO. IND.
KANAWHA VALLEY POWER CO. W. VA.
KENTUCKY & WEST VIRGINIA POWER CO., INC. KY.
KINGSPORT UTILITIES, INC. TENN.
OHIO POWER CO., THE OHIO
OHIO VALLEY ELECTRIC CORP., INC. W. VA.
OHIO VALLEY ELECTRIC CO., THE PA.
WHEELING ELECTRIC CO. W. VA., OHIO
WINDSOR OHIO PUBLIC SERVICE CO. OHIO
MILES
100
200
300
400

important load centers were connected by 132 kv. lines, thus allowing interchange of power throughout the system. Since that time, interconnections have been extended and increased, resulting in a looping of the Ohio properties. Ties have been made with large non-affiliates, including TVA. However, the system supplied practically all of its own energy requirements, and in 1944 sold more than 10 per cent of its total generation to other electric utilities. With the exception of the Twin Branch plant, located near South Bend, Indiana, the principal generating stations were located in bituminous coal districts in southeastern Ohio and West Virginia. Total name plate capacity of steam plants in the system was about 1 1/2 million kw., and in addition, there was about 200,000 kw. of hydro capacity. Energy interchange within the system has been substantial. In 1944, more than 1/4 of the 9 billion kwh. generated in the system was obtained by a company other than the generating company. Capacity was clearly planned from the standpoint of the whole system, rather than by the individual operating companies. Although the record did not so state, it seems probable that the system service company did this planning for all capacity.

According to the Commission, the record indicated that

> system fuel costs and losses between point of generation and point of delivery to consumers are well below the national average, and plant thermal performance is substantially better than the national average.

This, of course, would indicate efficient management, at least in part.

The Commission hesitated in determining that such a large system met the size requirements of Section 2 (a) (29) (A), but in view of the fact that it was not overpoweringly large in any one state, and no state commission or other body opposed such determination, it was felt undesirable economically to break it up, since the high degree of coordination and economical operation "in part, appeared to be due to common control." It was stated that this appeared to approach the permissible size of permissible systems under the Act.

Just as in the case of the Southern system,[1] this meant that neither of the other two properties could be retained as additional systems, since the (C) standards could not be met, even though American Gas and Electric Company claimed losses of substantial economies under clause (A). It was said that these two companies would have to make substantial increases in personnel in order to do the work previously performed by the service company.[2] Such personnel for each company would include "a president [!], vice-president,

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[1] See below, p. 215.

[2] The service company performed the following services: administrative; finance and accounting; legal; statistical; filing, mail and telephone; stock, record, and dividend disoursements; commercial and new business; purchasing; insurance and retirement records; auditing; field auditing; field appraisals; engineering.

secretary, treasurer, controller, chief auditor, counsel, statistician, purchasing agent, two engineers, and additional clerical, stenographic and other office employees."

It was stated that this would cost each company substantially more than to have such services performed by the service company.

The Commission thought the estimates "unduly high," and pointed out that the cost of maintaining the holding company over the two subsidiaries, "while difficult of isolation, are undoubtedly substantial." Nor did the Commission think that the credit and investment standings of the two companies were such that capital costs would increase upon separation. Therefore, it could not make the required findings under either clause (A) or (C). The two properties were ordered divested.

The stocks of two companies were sold to the general public; the Pennsylvania company, Scranton Electric, was sold in May, 1946,[1] and the New Jersey property, Atlantic City Electric and its subsidiary, Deepwater Operating Company, was sold in March, 1949.[2]

With the large amount of cash on hand from the sale of the Scranton property, and with the expectation of more to come, American Gas and Electric became interested in

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[1] Holding Company Act Release 6565.

[2] Holding Company Act Releases 7335 and 8617.

acquiring properties which it might integrate economically with its Central system. It asked the Commission to approve its plan to bid on the common stock of Columbus and Southern Ohio Electric Company, a subsidiary of United Light and Railways Company, which was under Section 11 (b) (1) orders to divest Columbus and Southern Ohio. The following information is contained in the Section 10 (c) (2) decision on this plan.[1]

Columbus and Southern Ohio served two non-contiguous but interconnected areas in central and southern Ohio, one segment of which separated the Central system's service areas.[2] It was completely integrated, its two main generators, located in Columbus, servicing both areas. As of March 31, 1946, total book assets were about 73 million dollars, with 54 million dollars of this representing electric plant, and gross electric operating revenues for the 12 months ending on the same date were about 14 1/2 million dollars. Generating capacity was about 210,000 kw., and during the above period sales were about 2/3 billion kwh.

Savings claimed through coordination of facilities of the company with the central system were substantial. Savings in generating capacity, due to the elimination of the necessity for Columbus and Southern Ohio to maintain spinning

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[1] Holding Company Act Release 6639, May 17, 1946.

[2] See map of United Light and Power system below, p. 272.

reserves were estimated at 15,000 kw.[1] A further saving of 15,000 kw. of capacity was further "conservatively" estimated to accrue due to elimination of Columbus and Southern Ohio's need for stand-by reserve to provide for taking large generating units out of service for overhaul. Because of diversity of load peaks, it was estimated another 5,000 kw. of capacity could be saved.[2] Of course, these were future savings, eliminating the need for new capacity in these amounts as demand grew. The Commission conceded that the estimates seemed correct.

It was estimated that these capacity savings would amount to 5 million dollars, or 500 thousand dollars annually. In addition, annual savings to Columbus and Southern Ohio, as a subsidiary of American Gas and Electric, in construction and engineering and purchase of construction materials, were estimated at $7,875. Savings in administrative and general expenses were expected to total $197,865 annually.

Estimated savings in operating expenses were even larger. Annual savings in generation costs, resulting from the use of the Central system's lower cost units for base

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[1] Spinning reserves are generators running, but not under load. In general, some capacity is always "spinning" in order to take care of sudden increases in demand, in order that there be no interruption of service.

[2] These are examples of how economies may be obtained by integrating and coordinating separate systems, as was pointed out in chap. ii.

load, in place of the relatively high cost generation of Columbus and Southern Ohio's plants, would amount to $897,140. It was claimed that in the purchasing of fuel and materials annual savings in the amount of $129,524 would be realized. The Commission felt that not enough evidence had been presented to allow it to appraise thoroughly the savings in fuel costs, which American Gas and Electric insisted it could pass on to the company, but it was "willing to assume that some such savings might well occur." Energy losses would also diminish in the combined system, resulting in an annual saving of $70,611.

Capital savings would be offset by the costs of additional interconnection, which would total nearly 3 million dollars, or $298,000 as an annual capital offset. Total annual capital and operating savings would thus be $1,505,015. American Gas and Electric intended to spend about 6 million dollars to rehabilitate Columbus and Southern Ohio's system, mainly by looping the city of Columbus with transmission lines to strengthen and improve the quality of service.

It was also argued that the acquisition of the company by American Gas and Electric would benefit the whole Central system, since the service company could maintain its rate of work (Columbus and Southern Ohio approximated in size the two companies previously ordered divested).

In view of the statement in the Section 11 (b) (1) decision that the Central system approximated the maximum

allowable size under the Act, it is not surprising that the Commission did not approve this acquisition. It pointed out that it would increase the system's utility plant by 13 per cent, capacity by 12 per cent, sales (kwh.) by 8 per cent, and population served by 19 per cent. The combined system would serve 25 per cent of the population of the State of Ohio, instead of the 16 per cent then served by the Central system. The majority opinion held that such size could not meet the localized management and effectiveness of regulation provisions of the Act. In the vigorous dissenting opinion, Commissioner Caffrey noted in some detail the estimated savings,[1] and pointed out that the staff of the Commission had not been able to controvert the evidence or show that the estimates were not "conservative and reliable." He also stated that the Ohio State Commission had informed the Commission that it deemed the acquisition "advisable"; that the Commission itself would have continuing jurisdiction over the system; and that the acquisition would bring Columbus and Southern under the jurisdiction of the Federal Power Commission. He failed to see that the acquisition would so change the management as to fail to meet the "localized" requirement of the Act.[2] He noted also that the generating

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[1] This information was used above in the discussion.

[2] This point, while interesting, is, of course, not relevant here.

plants of Columbus and Southern Ohio were limited in their ability to expand economically, because of lack of available water for condensing purposes.

The majority opinion had some interesting things to say concerning the necessity of owning in order to coordinate facilities. The entire section is quoted below:

> In view of the emphasis which has been placed on the savings and increased efficiency which, it is asserted, would accompany the acquisition, it may not be inappropriate to note also the extent to which the physical benefits claimed to result from the acquisition may be achieved in other ways. While American Gas and Electric Company has insisted that all the coordinated operation and planning which is achievable under joint ownership cannot be achieved without it, American Gas and Electric Company has not claimed, and it cannot claim, that none of these benefits is achievable without joint ownership. The capacity of independently owned utilities to coordinate their operations and interchange power through mutual operation of power pools has been amply demonstrated in the history of utility operations in this country and was made obvious during the war. The history of American Gas and Electric Company itself dramatizes these possibilities. One of the most important plants of Ohio Power Company, at Windsor, contains generators separately owned by Ohio Power Company and Western Pennsylvania Company, non-affiliates. The generators are housed in a single building and are so operated that they can route power over the lines of either non-affiliate. The same type of situation exists in other locations in the Central system. During the war, Ohio Power Company and Columbus and Southern Ohio Electric Company, the very properties in issue, pooled their resources for common interchange.

However, the Commission has permitted American Gas and Electric to acquire three smaller properties to date under Section 10 (c) (2) proceedings. The first was the purchase of the common stock of Indiana Service Corporation from

Midland Utilities in December, 1946.[1] Midland (part of the old Insull empire) was under Section 11 (b) (2) order to solve certain voting and financial problems, and this sale was an "unusual" but acceptable way to help do this.

Indiana Service's territory centered around Fort Wayne, Indiana. It was flanked on the north, east and south by Indiana and Michigan Electric Company, a part of the Central system. Six high voltage lines, which linked parts of Indiana and Michigan, crossed Indiana Service's territory. It had one generating plant--at Fort Wayne, Indiana--which was 20 years old and very inefficient. Its generating costs (which exclude depreciation and fixed charges) were 9 mills/kwh. in 1944, compared to 3.15 mills/kwh. for the Twin Branch plant of Indiana and Michigan. The Company generated only about a quarter of its energy.requirements. It purchased almost all of the rest from Indiana and Michigan.[2] Its supply and distribution facilities were in large part already coordinated with those of the Central system. Indiana Service had no private source of reserve capacity, and depended for stand-by breakdown service on the Fort Wayne municipal system, with which it had a reciprocal agreement. It did not appear to be able

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[1] Holding Company Act Release 7054.

[2] Out of 252,500,000 kwh. purchased in 1945, 252,013,000 kwh. were bought from Indiana and Michigan. The remainder was purchased from Northern Indiana Public Service Company and Citizens Heat, Power and Light Company.

to increase its capacity because of lack of water supply. Any increased energy needs would therefore have to be purchased.

Although no specific evidence of economies was cited in the decision, the record convinced the Commission that further interconnection would result in ".... the development of improved and economical service for the entire area now served by the two companies." It would appear that the results of such interconnections would be prevention of outages in Indiana Service's territory by being tied to American Gas and Electric Company's stand-by capacity, and removal of the high cost plant from base-loading, and hence, lowering the cost of energy.

Apparently still concerned in justifying its previous decision, the Commission approved the acquisition on the grounds that Indiana Service was, to the extent of 75 per cent of its business, a distributor for the Central system, that it did not represent a major extension of operating territory, but rather a spur, or connecting link, and it did not materially enlarge the system. The system was enlarged by the following percentages: utility plant, 3 per cent; capacity, 2 per cent; population served, 6 1/2 per cent; sales (kwh.), 4 per cent (without adjustment for the duplication with American Gas and Electric Company).

About a year later, the Commission approved American Gas and Electric's bidding on the common stock of Citizens

Heat, Light and Power Company, the only electric property left to United Public Utilities Corporation, and a few months later approved the purchase.[1] The property was small, serving only 5,600 customers[2] in and around Winchester, Indiana, and it adjoined Indiana and Michigan Electric Company on the west. It purchased all its energy from Public Service Company of Indiana on a six months' notice contract.[3] A 132 kv. line of the Central system transversed a portion of Citizens' territory. American Gas and Electric proposed to interconnect and eventually to amalgamate the property with Indiana and Michigan.

The Commission determined that all energy requirements of Citizens could be economically met by Indiana and Michigan, and that the Central system would benefit from the increased load factor. "Furthermore, the coordination of operation and management of Citizens' properties with those of the American system is expected to produce additional economies accruing to the advantage of both." The Commission noted that Indiana and Michigan's rates were lower than those of Citizens, and they would be applied in Citizen's service area if that company

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[1] Holding Company Act Releases 7915 and 8453.

[2] This was 1/5 as many as Indiana Service Corporation had served.

[3] Public Service had the opportunity, but did not bid on this property.

were acquired. American Gas and Electric expected to offset this with lowered costs and additional sales. It was stated that Indiana and Michigan sold about 50 per cent more energy to residential users and 33 per cent more to rural customers, on the average, than did Citizens, and American Gas and Electric explained that the higher averages for Indiana and Michigan were due to lower rates.

The third property acquired by American Gas and Electric was Central Ohio Light and Power Company. This company had formerly been a subsidiary of Crescent Public Service Company, but its stock had been distributed to the owners of that company as a liquidating dividend under a Section 11 (e) (voluntary) plan.[1] The acquisition was approved on December 19, 1950.[2]

Central Ohio Light and Power served two separate areas, about 100 miles apart. One was around Findlay (western division), and the other centered around Wooster (eastern division). The eastern division had no generating capacity and purchased all its power from the Ohio Edison Company.

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[1] Crescent's other property had been Colorado Central Power Company, which served as a distributor in three suburbs of Denver. In Holding Company Act Release 5359, the two properties had been held not an integrated system or systems under clause (B). The company had elected to dissolve in order to meet the requirements, both of that section and Section 11 (b) (2). See Holding Company Act Release 6378.

[2] Holding Company Act Release 10294.

The western division had 55,000 kw. capacity, sufficient to meet its own needs and to sell power to the Dayton Power Company. Neither division was connected directly with American Gas and Electric, although both were in the "general service area" of American Gas and Electric's Ohio properties. The company was in most respects smaller than Indiana General Service Company. Also, American Gas and Electric had grown internally in the four years intervening between the two cases. Thus, the increases due to the acquisition were relatively small: gross plant would be increased by 2 per cent; capacity by 2.3 per cent; sales (kwh.) by 2 per cent; population served by 2 per cent.

American Gas and Electric's plan was to interconnect with the western division in order to "better [utilize] generating facilities," and to "reinforce service." One of the western division's three plants would be shut down entirely, another utilized on a stand-by basis only, and the third would be operated on a two-shift instead of a three-shift basis. Through central dispatching, to utilize lowest cost unused generators, it was estimated by American Gas and Electric that gross savings in the western division would be $515,000 in 1951, $614,000 in 1952, and $684,000 in 1953. The reason for the differences was not noted. The cost of interconnecting the division with the Central system totaled about $696,000 or, on the 10 per cent basis used previously by the system, about $70,000 annually.

American Gas and Electric intended to build a single-circuit wood pole 132 kv. line near Wooster, Ohio, whether this property was acquired or not, because of the overloading of other circuits. If the eastern division was acquired, the plan was to build a two-circuit steel pole line as far as Wooster (from Canton, a distance of 30 miles) in place of the other circuit, and build from Wooster on as before. The estimated addition cost to do this was $640,000, or, again on a 10 per cent basis, $64,000 annually.

American Gas and Electric stated that by 1953 it would be able to deliver power to Wooster for 1.5 mills/kwh. less than the (then) present contract price of Ohio Edison. However, this contract would expire in 1951, and at Ohio Edison's new offered rates, the saving would be about .75 mill/kwh., or $78,000 annually. Hence the total operating savings in 1953 would be about $628,000. In addition, American Gas and Electric stated that about 1/4 million dollars a year could be saved through complete coordination of operating staffs and personnel of the two companies.

The Commission said: "While the record is not conclusive as to these estimated economies, and they are less apparent in the eastern than in the western division, we are persuaded as to the effectuation of substantial economies under the proposed program." Emphasis was again placed on the relatively minor increase in size of American Gas and Electric by the acquisition. The Commission noted in the

decision that, while the requirements of Section 10 (c) (2) had been met, in its opinion, that this did not necessarily mean that this was the best possible solution. Ohio Edison had expressed an interest in acquiring the eastern division of Central Ohio Light and Power, and American Gas and Electric officials were willing, after acquiring the property to "undertake a further study of the integration prospects of its [American Gas and Electric's] Ohio properties with a view toward working out with the Ohio Edison Company or others, a sale or exchange of utility properties in that state." To date, there has been no apparent result from such talks.

Over 98 per cent of the stock of Central Ohio Light and Power was acquired by American Gas and Electric in early 1951, in exchange for its own stock.[1] Indiana Service Corporation was merged into Indiana and Michigan on August 31, 1948, and the holding company planned, at the time of acquisition to merge Citizens into the same subsidiary, although this has not been done to date.

Analysis

It is apparent that there could be no loss of plant economies to the subsidiaries of American Gas and Electric due to Section 11 (b) (1) orders, since the only properties ordered divested were not connected in any way with the

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[1] Moody's Manual, 1951.

retainable central system, nor were they capable of interconnection in any economic sense of the term.

It is just as apparent that plant economies were achieved by the acquisition of Citizens, Indiana Service, and Central Ohio Light and Power. In view of the evidence in these cases, and what has been said in Chapter II, savings would be of a large order of magnitude for these companies, and of a smaller order of magnitude for the system as a whole. In the only one of these cases where estimated operational savings were quantified, that of Central Ohio Light and Power, the estimated 1953 savings amounted to about 15 per cent of 1949 gross electric operating revenues. Due to changes in technology load growth, costs and rates, as well as the problem of getting data, it does not seem possible to check these figures. But the Public Utilities Division of the Commission did not dispute them, and there seems to be no reason to doubt their magnitude.

It seems unfortunate, economically, that American Gas and Electric was not allowed to acquire Columbus and Southern Ohio. Estimated savings there were about 10 per cent of gross electric operating revenues. While the Commission was correct in saying that ownership was not essential to obtaining all the economies and that at least some degree of coordination by independents can be achieved, such does not seem to have been the result in this case. A 120,000 kw. generating station was completed by Columbus and Southern Ohio

in 1949, and total capacity of the system in 1950 was 320,000 kw.[1] There is practically no interchange of power between Columbus and Southern Ohio and any other utility, either by purchase and sale or agreement.[2]

There is the possibility of loss of firm economies to the two divested companies, Atlantic City and Scranton. It will be remembered that substantial increases in personnel were anticipated for the two companies as independents. The available data do not appear to bear this out to any extent.

In the case of Atlantic City, it is impossible to tell what part of the salary increases in 1949 and 1950 were due to separation because of the acquisition of the two smaller utilities, but it will be noted that general officers and executives' salary total is lower in 1950 than in 1946. The average of administrative and general expenses as a percentage of gross electric operating revenue as a subsidiary (1938-1948) is 4.4 per cent; the average as an independent is 4.2 per cent, a decline of 5 per cent.

Scranton's "other office salaries" jumped after separation (in 1946), although the salaries of general officers and executives did not, or, at least, not until 1949, and the connection there to separation seems tenuous.

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[1] A 90,000 kw. station seems to have been taken out of service and another 80,000 kw. station built.

[2] The above information was abstracted from Statistics, 1946-1950.

TABLE 6

DIVESTED SUBSIDIARIES OF AMERICAN GAS AND ELECTRIC COMPANY, ATLANTIC CITY ELECTRIC COMPANY, AND SCRANTON ELECTRIC COMPANY

Year	Administrative and General Expenses (Excluding the Pension Account) as a Percentage of Gross Electric Operating Revenue		Salaries of General Officers & Executives		Other Office Salaries	
	Atlantic City	Scranton	Atlantic City	Scranton	Atlantic City	Scranton
1938	3.7	5.7	$33,222	$38,672	$ 79,655	$ 51,401
1939	4.6	7.1	39,475	36,610	115,743	63,326
1940	5.3	6.8	41,374	35,616	130,438	79,503
1941	5.6	5.4	30,749	34,661	118,777	101,963
1942	5.4	5.4	32,526	34,124	129,879	99,485
1943	4.3	5.1	31,416	21,959	130,560	110,343
1944	3.8	4.4	33,830	22,191	134,944	111,300
1945	3.6	4.2	45,543	23,676	143,941	118,809
1946	3.9	4.2	67,321	28,195	192,130	146,557
1947	3.9	4.5	55,968	27,672	217,721	175,674
1948	3.8	4.0	40,755	27,707	246,868	189,361
1949	4.2[a]	5.3	52,210[a]	36,083	253,523[a]	222,767
1950	4.2[b]	5.3	64,052[b]	54,737	291,286[b]	245,536

[a] Includes South Jersey Power and Light Company, acquired 30 June, 1949.

[b] Includes Deepwater Light and Power Company, acquired 23 July, 1950.

The adjusted average of general and administrative expense as a per cent of gross electric operating revenue does not seem to bear out the claim of loss of economies. The average for the years 1938-1945 is 5.5 per cent, while the average for 1947-1950 is 4.9 per cent, a decline of 11 per cent.

Comparing these declines with the average declines for all companies in the United States for the same periods[1] indicates that firm costs of Scranton declined slightly, relative to the national average, while Atlantic City's increased slightly more, relative to the national average.

Since the size of the system was changed so slightly by the separation of these companies, it seems reasonable to conclude that firm economies should not have been affected for American Gas and Electric's subsidiary. This seems especially true, due to the addition of the three companies already noted. The following table contains the relevant data for the "Central system" companies of American Gas and Electric Company:

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[1] See Appendix.

TABLE 7

RETAINED SUBSIDIARIES OF AMERICAN GAS AND ELECTRIC COMPANY
Administrative and General Expenses (Excluding the Pension Account) as a Percentage of Gross Electric Operating Revenue

Year	Indiana & Michigan Electric Company[a]	Kentucky & West Virginia Power Company	Ohio Power Company	Appalachian Electric Power Company
1938	4.6	4.7	3.6	4.1
1939	5.6	9.2	3.5	3.9
1940	5.5	8.4	3.3	3.9
1941	4.3	7.1	3.0	3.6
1942	3.8	5.1	3.3	3.6
1943	3.6	4.8	3.4	3.8
1944	3.1	4.0	3.2	3.8
1945	3.5	4.2	3.1	3.5
1946	3.9	4.9	3.4	3.9
1947	3.8	4.8	3.3	3.9
1948	3.4	4.2	3.1	3.4
1949	4.0	3.8	3.3	3.5
1950	3.7	3.6	3.3	3.1

[a] Data adjusted to include Indiana General Service Company (an American Gas and Electric Company subsidiary) merged February 6, 1945, and Indiana Service Corporation, merged August 31, 1948.

The averages as subsidiaries of Electric Bond and Share, and as "independents" (American Gas and Electric became legally independent of Electric Bond and Share in 1947) are as follows: Indiana and Michigan, 4.2 per cent and 3.7 per cent, a decline of 12 per cent; Kentucky and West Virginia, 5.8 per cent and 3.9 per cent, a decline of 33 per cent;

Ohio Power, 3.3 per cent and 3.2 per cent, a decline of 3 per cent; Appalachian Electric, 3.8 per cent and 3.3 per cent, a decline of 13 per cent. For the system as a whole, the decline was about 10 per cent. The decline is slightly greater than the national average for the same period, indicating little change, perhaps a slight gain, in firm economies.

Due to the recentness of acquisition and lack of data, it is not possible to determine the effects of acquisition by American Gas and Electric on two of the companies acquired by it as an independent holding company.[1] The effect on Citizens can be shown, however, since it was acquired in 1948, and it has not as yet been merged.

TABLE 8

ACQUIRED SUBSIDIARY OF AMERICAN GAS AND ELECTRIC COMPANY
Administrative and General Expenses (Excluding the Pension Account) as a Percentage of Gross Electric Operating Revenues for Citizens Heat Light and Power Company

1938	3.2
1939	3.4
1940	5.2
1941	3.3
1942	3.8
1943	4.2
1944	3.1
1945	3.7
1946	3.7
1947	2.9
1948	1.8
1949	1.3
1950	1.5

[1] All three of these companies had been subsidiaries of other holding company systems.

The averages of the figures before acquisition by American Gas and Electric (that is, while Citizens was still a subsidiary of United Public Utilities Corporation) is 3.7 per cent. For 1949 and 1950, the two full years of American Gas and Electric Company affiliation, the average is 1.4 per cent, a decline of 62 per cent. Gains, rather than losses, in firm economies seem to have resulted from the inter-holding company transfer of the property. It seems doubtful that losses should be anticipated for the other two acquisitions, although there is no quantitative way to demonstrate this.

It is interesting to note that, although the logic of operations seemed to indicate that these companies should be coordinated with American Gas and Electric Company (or some other system), this was not accomplished until those holding companies which controlled the properties were ordered by the Commission to divest them.

American Power and Light Company; Electric Power and Light Company; National Power and Light Company

These three sub-holding companies in the Electric Bond and Share system existed, prior to 1935, solely on the books of Electric Bond and Share. In November, 1935, after the passage of the Act, there was a general revision in organization. The service department of Electric Bond and Share was transferred to a newly-formed subsidiary, Ebasco Service, Incorporated, which was formed to carry on all the servicing

activities of the three above-named companies previously performed by Electric Bond and Share itself. Simultaneously, each of these sub-holding companies was given a complement of officers and employees of its own, and each was assigned a separate suite of offices in the Electric Bond and Share building. All of this leads to the conclusion that the three were intermediate steps in the holding company system with entirely different functions than American Gas and Electric, which actively managed what was, on the whole, a coordinated operating system. Partly because of this, the three are here considered as a group. In addition, no Section 11 (b) (1) action as such was ever taken against any of them, or Electric Bond and Share itself. Dissolution of these major portions of the system was due entirely to Section 11 (b) (2) orders. All three of these sub-holding companies were ordered dissolved under this section,[1] and the actual divestment of operating subsidiaries has been, by and large, a by-product of this process. However, in the process, two integrated systems were formed, and some interesting details on firm economies attributable to this holding company are in the record. It is these aspects of the proceedings which are of interest here.

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[1] National Power and Light Company, Holding Company Act Release 2962; American Power and Light Company and Electric Power and Light Company, Holding Company Act Release 3750.

The map of the electric subsidiaries of these three sub-holding companies shows three sections of the country in which different subsidiaries are in geographic proximity; the Northwest, the middle South (Arkansas, Louisiana and Mississippi) and Texas. Two of the Texas properties, Texas Power and Light Company and Texas Electric Service Company, were subsidiaries of American Power and Light, while the third, Dallas Power and Light Company, was a subsidiary of Electric Power and Light.[1]

In 1945, the Commission approved a Section 11 (e) plan for formation of a new sub-holding company, Texas Utilities, with these three companies as its operating system.[2] This was in part a Section 10 (c) (2) case, in that American Power and Light had to acquire from Electric Power and Light the stock of Dallas, although, of course, it required approval under Section 11 (b). The combined properties did not result in a particularly large system. Using 1945 data, the combined gross plant per books was about 150 million dollars, and combined gross operating revenue amounted to about 41 million dollars. Population served was estimated at about

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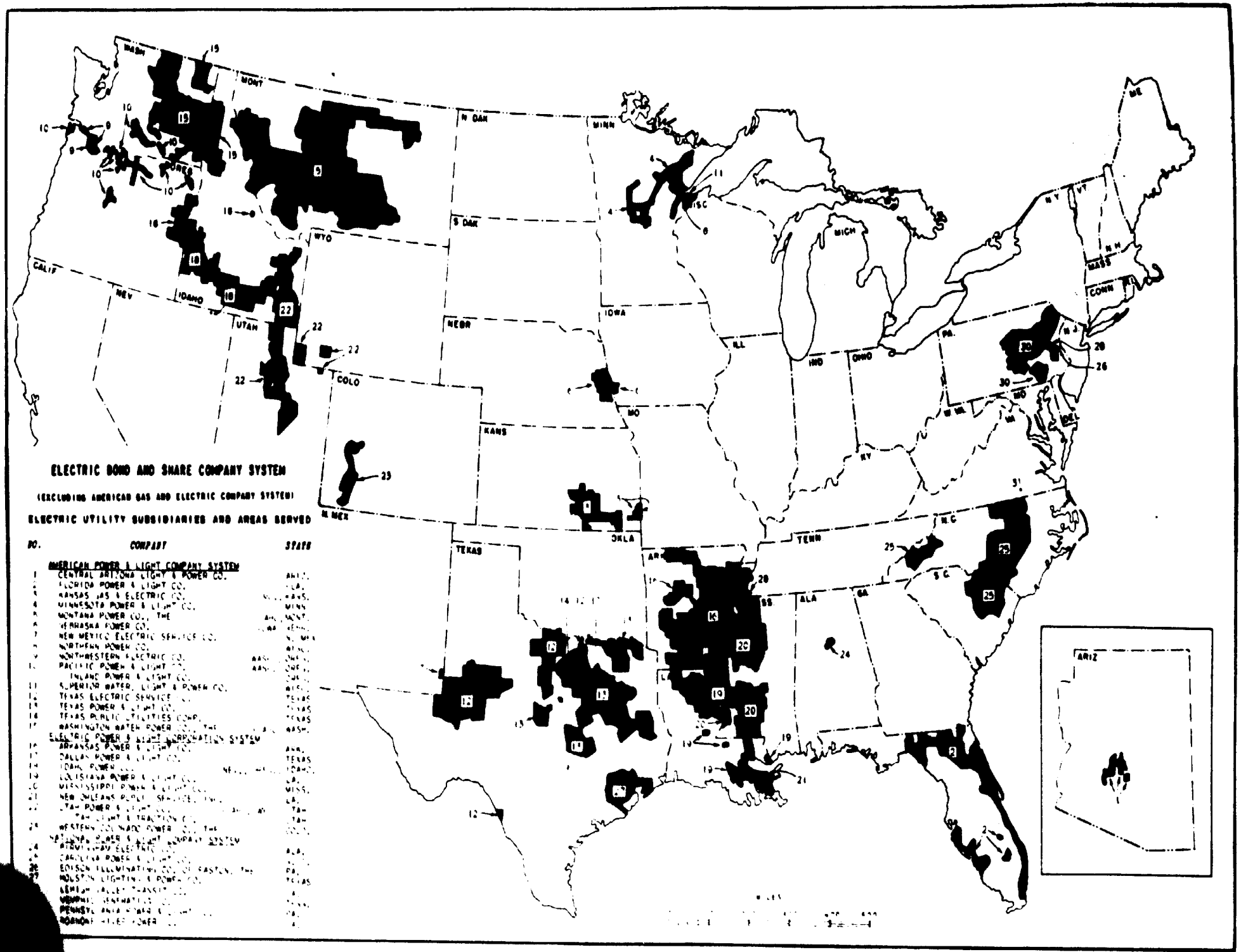
[1] Houston Lighting and Power Company, a former subsidiary of National Power and Light, was also in this area, but it was no longer a subsidiary, as its common stock had been exchanged for the preferred of its parent, and the balance sold. Holding Company Act Release 3612, and Moody's Manual, 1943.

[2] Holding Company Act Release 6158.



ELECTRIC BOND AND SHARE COMPANY SYSTEM

(EXCLUDING AMERICAN GAS AND ELECTRIC COMPANY SYSTEM)

ELECTRIC UTILITY SUBSIDIARIES AND AREAS SERVED

NO.	COMPANY	STATE
	AMERICAN POWER & LIGHT COMPANY SYSTEM	
1	CENTRAL ARIZONA LIGHT & POWER CO.	ARIZ.
2	FLORIDA POWER & LIGHT CO.	FLA.
3	KANSAS GAS & ELECTRIC CO.	KANS.
4	MINNESOTA POWER & LIGHT CO.	MINN.
5	MONTANA POWER CO., THE	MONT.
6	NEBRASKA POWER CO.	NEBR.
7	NEW MEXICO ELECTRIC SERVICE CO.	N. MEX.
8	NORTHERN POWER CO.	MONT.
9	NORTHWESTERN ELECTRIC CO.	ORE.
10	PACIFIC POWER & LIGHT CO.	ORE.
	INLAND POWER & LIGHT CO.	IDAHO
11	SUPERIOR WATER, LIGHT & POWER CO.	WIS.
12	TEXAS ELECTRIC SERVICE CO.	TEXAS
13	TEXAS POWER & LIGHT CO.	TEXAS
14	TEXAS PUBLIC UTILITIES CORP.	TEXAS
15	WASHINGTON WATER POWER CO., THE	WASH.
	ELECTRIC POWER & LIGHT CORPORATION SYSTEM	
16	ARKANSAS POWER & LIGHT CO.	ARK.
17	DALLAS POWER & LIGHT CO.	TEXAS
18	IDAHO POWER CO.	IDAHO
19	LOUISIANA POWER & LIGHT CO.	LA.
20	MISSISSIPPI POWER & LIGHT CO.	MISS.
21	NEW ORLEANS PUBLIC SERVICE INC.	LA.
22	UTAH POWER & LIGHT CO.	UTAH
	UTAH LIGHT & TRACTION CO.	UTAH
23	WESTERN COLORADO POWER CO., THE	COLO.
	NATIONAL POWER & LIGHT COMPANY SYSTEM	
24	BIRMINGHAM ELECTRIC CO.	ALA.
25	CAROLINA POWER & LIGHT CO.	N.C.
26	EDISON ILLUMINATING CO. OF EASTON, THE	PA.
27	HOUSTON LIGHTING & POWER CO.	TEXAS
	LEHIGH VALLEY TRANSIT CO.	PA.
	MEMPHIS LIGHT, GAS & WATER DIV.	TENN.
	PENNSYLVANIA POWER & LIGHT CO.	PA.
	ROANOKE RAILWAY & POWER CO.	VA.

1 1/2 million. Although there were large gaps in the service areas of the companies, they had been interconnected since 1912, and the present interconnection network was substantially completed in 1932. The interconnections were of sufficient capacity to permit transfer of large blocks of power, and there was "considerable" interchange on a contractual basis among the three companies, about one-sixth of all energy generated being used by other than the generating company.[1] Capacity was also shared on a contractual basis among the three companies. The companies utilized a central load dispatcher, located in Dallas. It was stated that the companies had been planning generating capacity on an area basis for "a considerable period of time." The companies contended, and the Commission accepted, that considerable economies had been obtained by this joint planning and coordinated operation, but the testimony indicated that holding company control of the three operating companies as a unit, as compared with the (then) present contractual arrangements, would permit "increased long range planning" and "a higher degree of coordination in operation" of the properties.

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[1] The 1944 interchanges were as follows:

	Dallas	Texas Electric	Texas Power
Net generation (M. kwh.)	651,272	866,740	976,622
Energy delivered to Texas Power (M. kwh.) by	37,455	205,050	--
Energy delivered to Texas Electric (M. kwh.) by	--	--	182,128
Energy delivered to Dallas (M. kwh.) by	--	--	2,115

The Commission went on to say that it saw the possibility of "substantial saving" if the properties were merged into a single operating company, and apparently the system would not have objected to this. It was impossible to do this, however, since, in Texas, regulation is done by the municipalities. Dallas' franchise contained detailed provisions, particularly with respect to rates, and that city would not consent to the merger, since it felt that this would impair the effectiveness of its regulation.

The cash sale of Dallas Power and Light by Electric Power and Light to American Power and Light was approved, and so was the formation of the new holding company, with the stipulation that it be severed by American Power and Light within one year.

Although this case was not a Section 11 (b) (1) decision, Texas Public Utilities Corporation was recognized as an integrated system within the meaning of that section.[1] In 1950, this holding company was exempted from regulation under the Act, except for the acquisition of non-affiliates.[2]

Electric Power and Light's properties in the middle South region were also integrated under a new holding company, Middle South Utilities, Incorporated. A Section 11 (e)

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[1] Holding Company Act Release 9359-A; Moody's Manual, 1951.

[2] Under Section 3 (a) (1); Moody's Manual, 1951.

(voluntary) plan to accomplish this was finally approved in March, 1949.[1] The operating utilities involved were Arkansas Power and Light Company, Louisiana Power and Light Company, Mississippi Power and Light Company, and New Orleans Public Service, Inc., all of which were electric utility subsidiaries of Electric Power and Light.

It will be noted on the map that these companies' operating territories are a contiguous block, just to the west of, and adjoining the operating territory of, the Southern Company. As of 1947, the estimated population served was somewhat less than 4 million. Total gross operating revenues were about 80 million dollars, about 55 million dollars of which was electric.[2] Gross book value of plant was about 225 million dollars, of which probably 2/3 was electric plant, although no breakdown is given for the various companies. No data were given on generating capacity or total generation in the system.

The companies were all interconnected, and there had been system planning and building of capacity and central load dispatching since 1930.[3] Mississippi Power and Light received

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[1] Holding Company Act Release 8889. Various other plans to accomplish the same purpose were introduced earlier. Holding Company Act Releases 6768 and 8086.

[2] The rest of the revenues were from transportation and gas.

[3] Thus, capacity for the system was concentrated in Louisiana and northeast Arkansas in order to obtain the most economical and efficient generating capacity for the system as a whole.

the bulk of its energy requirements from Louisiana Power and Light and Arkansas Power and Light, and Louisiana Power and Light supplied a substantial portion of Arkansas Power and Light's requirements. New Orleans Public Service supplied all the energy for Louisiana Power and Light's southern area.

It was argued by a group of stockholders who contested the plan, that the new holding company was unnecessary to obtain the benefits of integration (which they did not challenge), and that through intercompany contracts, interlocking directorates or other forms of voluntary agreements, the same degree of integration could be achieved, thus saving $763,000 annually, the estimated annual expenses of Middle South. The Commission did not agree. It did agree that holding companies necessitate expense, but that it was not possible, in this case, to merge or consolidate the properties.[1] It pointed out that there is a limit to the amount of cooperation possible by independents.

> Voluntary cooperation to achieve benefits to each of several separate entities, as through power interchange contracts, is a very different thing from the operation of properties as a single system. It is the latter which constitutes integration within the meaning of the Act and which is claimed by the company to exist among these properties and, as we understand it, is assumed by the committee to be the result of its alternative proposal. Such integrated operation, even if it could be achieved in the manner suggested, assumes to a considerable degree that separate corporate entities might be called on to sacrifice their particular interests

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[1] Presumably because of state laws, or the opposition of state commissions.

for the over-all good. While this creates no problem where the entities are owned by the same group of people in the same proportion through a holding company, it creates an insuperable difficulty where the entities are, as would be the case under the committee's proposal, owned by different groups.

Therefore, the plan was approved, although it was specifically stated that the question of meeting the requirements of Section 11 (b) (1) was still to be considered. Although such decision has not been made to date, there can be little doubt that the electric properties will be found to meet that section's requirements, although the gas and transportation properties will no doubt be ordered divested.

A new holding company was set up in order to help solve the complex claims of security classes under the Section 11 (b) (2) proceedings. Although, as noted above, Electric Power and Light was under orders to dissolve, it probably could have remained as the holding company over this system, had it seemed desirable to do so. A new holding company was felt to be a simpler and better solution.

For some reason, the Northwest properties were not retained together as an integrated system, although this proposal was put forth by American Power and Light throughout the hearings. In a Section 11 (e) plan offered in 1948,[1] American Power and Light proposed to distribute all its assets (cash and common stock) to its owners except the Northwest

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[1] Holding Company Act Release 8157.

properties--Pacific Power and Light[1] and Washington Water Power--which were to be merged, or, if that were not possible, were to be retained as an integrated system under American Power and Light. In the decision on its final Section 11 (e) plan,[2] American Power and Light proposed, among other things, that it be divorced from the Electric Bond and Share system and remain in existence as a holding company over the two properties, which it believed constituted a single integrated system. The president of American Power and Light testified therein that it seemed desirable to retain the two companies as a unit, in order to preserve certain economies, "particularly in the purchase of power," which, it was thought, would be lost if the two companies were separately owned. The company also said that if it seemed desirable to sell the properties, they might be sold as a block. It was pointed out that in 1944, American Power and Light had wanted to merge the two companies by contributing the stock of Pacific Power and Light

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[1] Northwestern Electric Company had been merged into Pacific Power and Light Company earlier. See Holding Company Release 7369. It was stated in this decision that the two were interdependent with respect to facilities and for more than 20 years had been developed as a common operation. Northwestern was primarily a distributor and depended on Pacific for a large part of its energy requirements. Pacific owned a large part of the transmission, distribution "and other" facilities which were then being operated by Northwestern. It was asserted that by combination, the operating expenditures would be reduced $145,000 annually, but the reasoning behind this is not given.

[2] Holding Company Act Release 9359-A.

to Washington Water Power, but that the Washington state utility commission had refused permission to do so on the ground that it had no way of knowing how long the merged companies would remain under American Power and Light's control, and hence the merger would result in "undesirable complexity." The Commission had taken no action on this proposal pending state action.

No action on this particular part of the later plan was taken, pending further information,[1] but it did state that it recognized that a holding company might be an approved method of holding together an integrated system as contemplated by Section 11 (b) (1). However, the stock of Pacific Power and Light was sold in June, 1950, to investment bankers for public distribution,[2] and the cash from the sale was distributed to American Power and Light's stockholders, in partial liquidation.[3] Consumation of the sale in 1951 of Washington Water Power to a state public power agency was prevented by a state court order, on the grounds that part of the property was located in the state of Idaho. As far as is known, Washington Water Power is still a subsidiary

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[1] The Commission did approve the plan to partially liquidate by distribution of the common stock of the other subsidiaries to the stockholders of American Power and Light.

[2] Holding Company Act Release 9642.

[3] Holding Company Act Release 9948.

of American Power and Light.

What caused this apparent change in policy by American Power and Light is not known. It should be noted that Pacific Power and Light and Washington Water Power are interconnected at one point only, and that on October 1, 1950, Washington Water Power cancelled its contract for the sale of power to Pacific Power and Light.[1] No other information is available.

One subsidiary became a holding company. Northern Power Company was merged into Superior Water, Light and Power Company,[2] and then American Power and Light contributed the stock of Superior to Minnesota Power and Light Company,[3] which thus became a holding company in order to preserve (presumably) an integrated system which could not be merged into one company because of state laws, or state commission opposition. Northern Power was simply a distributor, and received all its energy from Minnesota and (after October, 1942) Superior. Prior to that data, Minnesota had supplied practically all of the energy distributed by Superior, and afterwards still supplied (and supplies) a substantial amount of power. The generating facilities were interconnected, and their use was coordinated by a central load dispatcher. To date, there has

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[1] Moody's Manual, 1951.

[2] Holding Company Act Release 4220. Both companies operated in the state of Wisconsin.

[3] Holding Company Act Release 5850.

been no decision as to whether the system meets the requirements of the Act, but it presumably does.

All of the subsidiaries of American Power and Light referred to above (with the exception of Pacific and Washington and including Texas Utilities) were distributed to its stockholders as a liquidating dividend in 1950.[1] As noted above, the stock of Pacific was sold to the public, and Washington still remains as a subsidiary to be divested. All other subsidiaries were sold publicly, with the exception of Nebraska Power Company, which was acquired by a Nebraska public power district in 1946, and New Mexico Electric Service Company, which was sold privately.[2]

The stock of Middle South was distributed to the stockholders of Electric Power and Light as a partial liquidating dividend. The stock of Idaho Power Company was sold to the public in 1943.[3] Dallas was acquired by Texas Utilities as noted above, and Electric Power and Light was required under Section 11 (b) (2) to surrender to Utah Power its common stock, which severed it from the system, the preferred stockholders becoming the new owners.[4]

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[1] Holding Company Act Releases 9359, 9389.

[2] Holding Company Act Release 6281.

[3] Holding Company Act Release 4527.

[4] Holding Company Act Release 6212.

National Power and Light sold Birmingham to the Southern Corporation.[1] In 1950, the Memphis Generating Company was sold to TVA.[2] All the other electric subsidiaries' stock was distributed as liquidating dividends.

Electric Bond and Share itself has or will divest all of the stocks received through the above liquidation processes. It intends to remain in business primarily as an investment company, and will have, as subsidiaries, American and Foreign Power, which controls utilities outside the United States, and Ebasco Services, the former system service company. In 1944, Ebasco cancelled, by mutual agreement, its service contracts with all subsidiaries, and therefore supplied services on an "if, as, and when requested" basis. It still does so, and as far as can be determined, still services all former subsidiaries, including the two new holding company systems, Texas Utilities and Middle South, as well as other utilities and non-utility businesses.

In the Section 11 (b) (2) hearings and decisions on the three subsidiary holding companies under discussion, it was claimed that they all served the purpose of raising capital for their subsidiaries, in the form of equity money and short term advances. The Commission investigated these claims and concluded that they simply were not true, either

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[1] See below, p. 217.

[2] Moody's Manual, 1951.

for the subsidiary holding companies or for Electric Bond and Share itself.

In the case of National,[1] the record disclosed "only one instance" of a substantial equity investment, amounting to about 8 million dollars paid for common stock of Houston Lighting and Power Company during the period 1922-1930. During this period, Houston had been paying dividends on its common stock of 17 per cent, and from 1930 to 1940, it paid 18 per cent. Other temporary investments were made, but through write-ups and sale of securities to the public, control was maintained with little or no net investment by the system. The total of short-term loads made by National Power and Light to its subsidiaries was 90 million dollars, but this was a cumulative total of loans outstanding for a period of days or weeks, repaid, and then, subsequently, reborrowed. On the same basis, upstream loans to National Power and Light by its subsidiaries total 68 million dollars. National Power and Light received repayment in full with interest at 6 per cent "although it frequently paid its subsidiaries a lower rate on upstream loans." The Commission concluded: "Whenever such subsidiaries borrowed from banks, they were able to obtain funds at no less favorable terms than charged by National, and sometimes on terms which appear more favorable."

The same conclusions were reached in the case of

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[1] Holding Company Act Release 2962.

American Power and Light and Electric Power and Light with respect to the same claims.[1] The Commission stated: "The fact of the matter is, as we have already indicated, that no substantial amount of risk capital was furnished to the operating companies by either the sub-holding companies or by Bond and Share." The record indicated that American Power and Light had, in the 32 years of its existence, supplied a total of $6,700,000 of risk capital to four of its subsidiaries. In one of the four cases, a $600,000 investment was required by the Commission in 1940. Of the $600,000 furnished two of the companies, the Commission said that "it appears that both companies could have sold their common stock on the market at prices considerably in excess" of the price paid by American. Electric Power and Light's record showed only three instances of risk capital supplied to electric subsidiaries. The Commission determined that since 1935, there were "perhaps a dozen instances" of short term (downstream) loans, at from 3 to 6 per cent, which rates, according to the Commission, were higher than the companies "most certainly" would have had to pay for bank loans.

Analysis

It does not appear that any plant economies were lost by any subsidiary of Bond and Share. The record does not

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[1] Holding Company Act Release 3750.

show any companies that were interconnected being required to separate. Approval was granted for all operating properties asked to be retained as a unit. While Washington and Pacific were separated, this was not due to Commission action, but rather to voluntary company action. Why the power contract between the two companies was cancelled is not known, but the Commission had no hand in this.

It will be remembered that additional operational economies were anticipated by the formation of Texas Utilities as a result of higher degree of coordination obtainable with direct holding company control. Previously, contractual arrangements had been used. From an operational standpoint, this tends to substantiate the argument that it is desirable for a holding company to concentrate its operations to a particular area. The same results could have been attained without application of the Act, since all the operating properties involved were subsidiaries of Bond and Share, but they had not been attained. The argument is further bolstered by the sale of Birmingham to the Southern Corporation. This economically desirable transfer took place only after application of the Act to both holding company systems. If the claimed operating savings due to the merger of Northwestern into Pacific is correct, then this, too, is attributable to application of the Act. The setting up of Minnesota and Middle South as holding companies seems to have been done entirely in order to prevent loss of operational economies.

On the basis of the record, there seems no reason to expect loss of firm economies, either. The fact that Electric Bond and Share, through American, Electric and National, did so little financing for the subsidiaries makes the claim of increased capital costs appear most dubious. Finally, since the former subsidiaries are permitted to, and do, use the services of Ebasco, the former system's service company, on the same basis as they have since 1944, there is no apparent reason for expecting increases in general and administrative expenses. The available data bear this out. The following table contains the relevant information for those former subsidiaries of American, Electric and National, which became independent prior to 1950.

TABLE 9

DIVESTED SUBSIDIARIES OF ELECTRIC BOND AND SHARE SUBSIDIARIES
General and Administrative Expenses (Excluding the Pension Account) as a Percentage of Gross Electric Operating Revenue

Year	Central Arizona Light & Power	Idaho Power	Kansas Gas & Electric	New Mexico Electric Service	Carolina Power	Pennsylvania Power & Light	Houston Light & Power
1938	6.8	7.8	8.1	9.6	6.3	6.7	7.7
1939	6.7	8.5	9.6	10.0	6.6	6.8	8.3
1940	5.9	8.4	9.1	9.9	6.1	6.6	7.6
1941	6.3	8.6	8.0	14.9	6.5	6.4	8.1
1942	5.5	8.4	9.5	13.4	6.6	5.7	8.4
1943	5.8	7.9[a]	7.2	10.1	5.5	5.6	9.5[a]
1944	6.0	7.9	5.6	11.3	5.5	5.4	10.3
1945	7.5[a]	7.7	6.6	10.2[a]	5.8	7.5	6.7
1946	6.4	7.6	5.9	12.7	6.2[a]	5.6[a]	7.0
1947	6.4	7.7	5.6	9.4	5.9	5.9	6.6
1948	6.2	6.5	5.6	7.1	5.8	5.9	6.8
1949	6.6	7.2	6.0[a]	6.5	6.0	6.0	6.2
1950	6.6	6.4	5.6	7.3	5.4	5.6	6.1

[a] Year divested.

The averages, before and after separation, for Central Arizona Light and Power are 6.3 per cent and 6.4 per cent, respectively, an average increase of 2 per cent. For Idaho Power, the comparable figures are 8.3 per cent and 7.3 per cent, a decline of 12 per cent. For the rest of the companies, the figures are: Kansas Gas and Electric Company, 7.3 per cent and 5.6 per cent, a decline of 23 per cent (the latter figure is for 1950 only, since the company became independent in the middle of 1949); New Mexico Electric Service, 11.2 per cent and 8.6 per cent, a decline of 23 per cent; Carolina Power, 6.1 per cent and 5.8 per cent, a decline of 5 per cent; Pennsylvania Power and Light, 6.3 per cent and 5.9 per cent, a decline of 6 per cent; Houston Light and Power, 8.0 per cent and 7.1 per cent, a decline of 11 per cent.

Comparing these with the national averages,[1] two of the companies show no relative change in firm costs, three show increases, one of them a marked increase, and two show declines, both marked. This does not seem to indicate general losses of firm economies to the divested subsidiaries which have retained their corporate identity as it was prior to divestiture.

The two new holding company systems, Middle South and Texas Utilities, have become independent of the Bond and Share system, the former in 1949, and the latter in 1950. Hence, Middle South is the only one for which data are available for

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[1] See Appendix.

at least one full year as an independent. The following table contains the data for it.

TABLE 10

MIDDLE SOUTH UTILITIES
General and Administrative Expenses (Excluding the Pension Account) as a Percentage of Gross Electric Operating Revenues

Year	Arkansas Power & Light Co.	Louisiana Power & Light Co.	New Orleans Public Service Co.	Mississippi Power & Light Co.
1938	10.0	5.6	5.4	9.0
1939	10.1	7.2	6.6	11.5
1940	10.1	7.7	6.0	10.1
1941	7.9	6.4	4.8	8.8
1942	9.6	7.3	5.3	8.8
1943	7.8	5.9	5.4	8.9
1944	8.3	5.3	5.6	7.5
1945	8.7	5.4	4.7	6.3
1946	8.9	6.3	5.8	7.5
1947	8.9	7.3	9.6	8.2
1948	8.6	7.0	7.0	8.1
1949	6.9	6.9	6.7	8.8
1950	8.0	7.3	6.2	8.3

The averages (1938-1949 and 1950) for each company are as follows: Arkansas Power and Light, 8.8 per cent and 8.0 per cent, a 9 per cent decline; Louisiana Power and Light, 6.5 per cent and 7.3 per cent, a 12 per cent increase; New Orleans Public Service, 6.1 per cent and 6.2 per cent, a 2 per cent increase; Mississippi Power and Light, 8.6 per cent and 8.3 per cent, a decline of 3 per cent.

Summing the data for the companies as a group gives an average of 7.6 per cent throughout 1949 and 7.4 per cent

in 1950, a 3 per cent decline. Comparing these figures with the national averages as above, it appears that there is some loss of firm economies. That this is true of the holding company, and not for the companies which are now individually independent, is surprising. However, the data for Middle South show only one year of independence, and any conclusions, therefore, can be only tentative.

Engineers Public Service Company

This company was formed in 1925 by Stone and Webster, Incorporated, a utility management firm. According to Bonbright and Means,[1] it was set up because of attempts by other holding company systems to acquire companies managed, but not actually controlled, by Stone and Webster.

By 1940 the system was of modest size, serving portions of 15 states, with an aggregate population of less than 2 1/2 million. Consolidated electric utility plant was less than 200 million dollars in 1940, with gross electric operating revenues for that year of about 44 million dollars (out of a total of 57 million dollars of gross revenues).[2]

In Section 11 (b) (1) hearings leading up to the first decision in this case,[3] Engineers stated that it was actively

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[1] Op. cit., p. 127.

[2] Holding Company Act Releases 1945, 2897, and Statistics, 1940.

[3] Holding Company Act Release 2897.

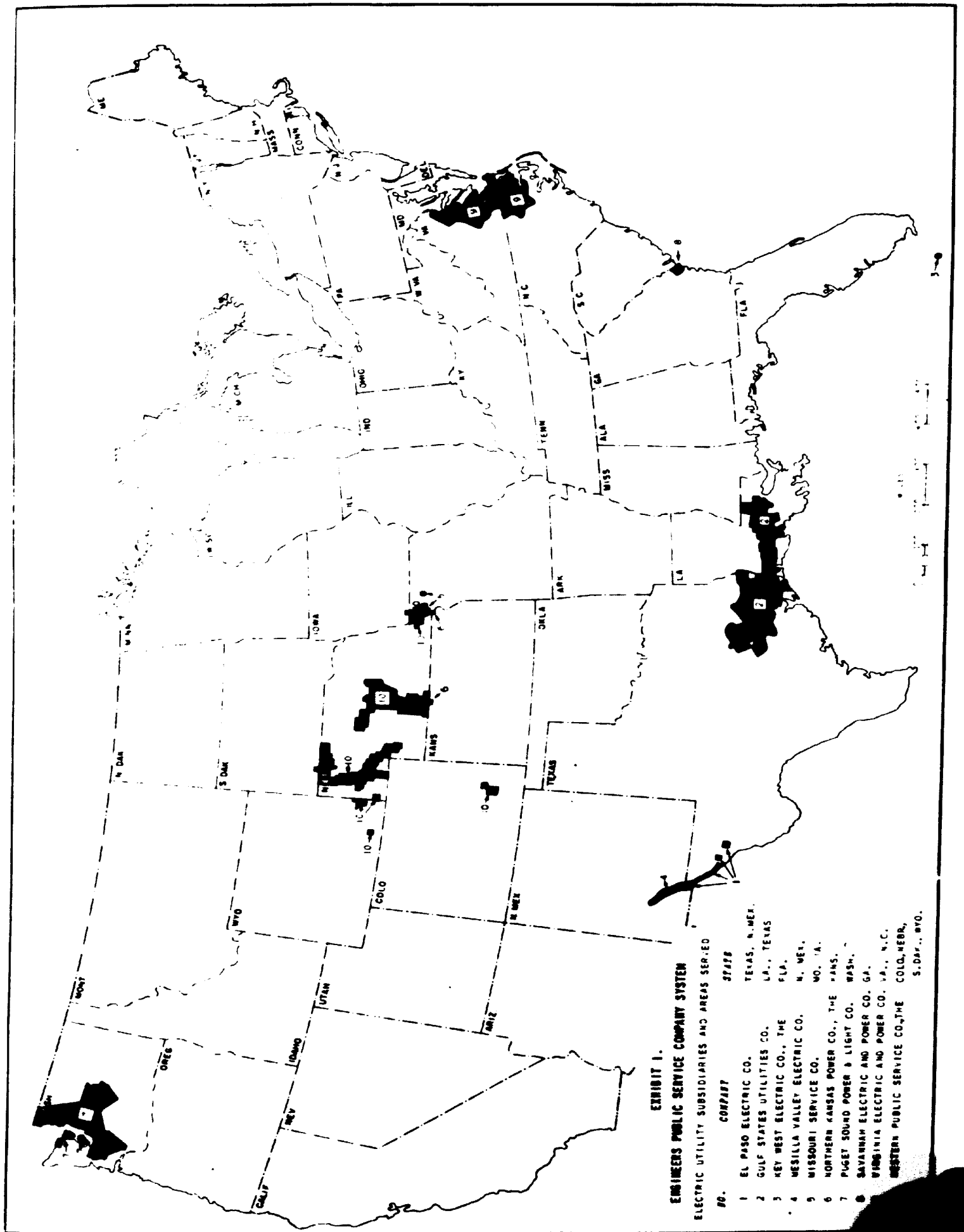
EXHIBIT I.
ENGINEERS PUBLIC SERVICE COMPANY SYSTEM
ELECTRIC UTILITY SUBSIDIARIES AND AREAS SERVED
NO. COMPANY STATE
1 EL PASO ELECTRIC CO. TEXAS, N.MEX.
2 GULF STATES UTILITIES CO. LA., TEXAS
3 KEY WEST ELECTRIC CO., THE FLA.
4 MESILLA VALLEY ELECTRIC CO. N. MEX.
5 MISSOURI SERVICE CO. MO. IA.
6 NORTHERN KANSAS POWER CO., THE KANS.
7 PUGET SOUND POWER & LIGHT CO. WASH.
8 SAVANNAH ELECTRIC AND POWER CO. GA.
9 VIRGINIA ELECTRIC AND POWER CO. VA., N.C.
10 WESTERN PUBLIC SERVICE CO.,THE COLO.,NEBR., S.DAK., WYO.

negotiating for the sale of Puget Sound Power and Light Company, and that the sale of Western Public Service Company seemed likely. Hence, there was no argument with the Commission's order that they, together with Key West Electric Company, must be disposed of. Nor was there any disagreement in determining that both Virginia Electric and Power Company and Gulf States Utilities, Incorporated, were each integrated systems. The disagreement came over whether both might be retained in the same system under clause (B). Engineers argued what has come to be known as the "two area interpretation" of this clause; that is, that the additional system or systems must be in one state or adjacent states, but that they need not be in the same state or in states adjacent to the main system. The Commission maintained the single area interpretation, holding that both Virginia and Gulf States could not be retained in the same system. The Commission's interpretation was later upheld by the courts.[1] Hence, the two companies were not retainable together. The Commission held that if Virginia were chosen as the main system, it did not appear that the Savannah Electric and Power Company could meet the (A) and (C) requirements, and all others would be excluded by (B); and that if Gulf States were chosen as the main system, it did not appear

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[1] Circuit Court of Appeals for the District of Columbia, 138F (2d) 936 (1943). Engineers petitioned for a writ of certiorari, but while this was pending, it complied with the Commission's order and the petition was dismissed as moot.

that El Paso Electric Company could meet the (A) and (C) requirements, and that all others were excluded by (B).[1]

The final Section 11 (b) (1) decision was handed down in September, 1942.[2] The first problem considered was whether Savannah was retainable with Virginia. The companies were described for the first time. Virginia, previously held to be an integrated system, was completely interconnected, and its generating capacity of 214,000 kw. met its own requirements and, in addition, there was some net outflow of energy to Carolina Power and Light Company, and Virginia Public Service Company. Savannah served the city of Savannah and environs and supplied all its own energy with a single steam plant of 31,200 kw. capacity. The thinly populated marsh land surrounding the city effectively isolated this system, although a connection with the Georgia Power Company was under construction at the time of the hearings.

Engineers claimed that each company's expenses would be increased by 28 thousand dollars annually if separated, on the following basis: the service company would not be able to render its services for a system as small as the combination

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[1] Although the company refused to choose which subsidiary it would pick as its original system, these two, together with Puget Sound, were by far the largest. Of the 57 million dollars gross revenues of the system, Virginia contributed 21 million dollars, Gulf States 11 million dollars, and Puget Sound 17 million dollars.

[2] Holding Company Act Release 3796.

of Virginia and Savannah, and, therefore, the services would have to be rendered by additional expert personnel, or by an independent service company. This would cost 56 thousand dollars per year less for the two companies, as a unit, than if they were operated independently. The services to be rendered were advice "with respect to taxes, insurance, procurement, accounting consultation, assistance in planning and executing financing operations, and public relations." On the basis of these figures, Virginia's administrative and general expenses would increase by less than .2 per cent of gross operating revenue and Savannah's by about 1.3 per cent. The Commission did not find that these were "substantial" economies within the meaning of the Act. In doing so, it pointed out that Congress was made aware of the possible loss of firm economies in testimony given during hearings on the Act.[1] The Commission also thought the figures were too large, for several reasons. First, the calculations included the gas and transport business of the two companies, when, in fact, these were not retainable. Second, it felt that the present staffs could do much of this work without outside help, pointing out that the present service company obtained its personnel from

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[1] However, it should be noted that, in the introductory sections of the Act, it is stated that the growth of holding company systems is not in the public interest when it "bears no relation to economy of management," or where there is "lack of economy of management." Sections 1 (b) (4) and 1 (b) (5).

the ranks of the operating companies' executives, thus demonstrating their capacity. Last, it felt that it was "not demonstrable" that experts could serve the two companies as a unit more economically than could an independent service company.

Precisely the same sort of arguments were used by both sides in facing the issue of whether El Paso was retainable with Gulf States as an additional system. Engineers estimated that expenses (of the same sort as above) would be increased by $44,800 annually, Gulf's by $12,000 and El Paso's by $32,800, if the two companies were separated, as compared to maintaining them under common control. These increases would be about .1 per cent of gross electric operating revenue for Gulf States and 1.2 per cent of gross electric operating revenue for El Paso. The Commission rejected the claim of losses on the same grounds as above, and asserted that this conclusion was borne out by the testimony of L. F. Yetman, the treasurer of El Paso, who indicated that, given the opportunity, the operating companies' executives could perform many of the functions contemplated for the added experts.

Gulf States had been held to be an integrated system earlier. It was entirely interconnected, with the exception of two very small segments at Alvin and Jasper, Texas, which were not capable of interconnection. The Commission here studied whether they might be retainable as additional systems. It did not find Alvin to be. This property, which was some 100 miles from the nearest system lines, was simply a distribution

system serving the town of Alvin. It received all its energy from Houston Lighting and Power Company, the service area of which entirely surrounded Alvin. The Commission did not find it to be an integrated system, and hence it was not retainable.

Jasper, 75 miles from the company's lines, had its own diesel generating plant, the operation of which was supervised by the Beaumont office of Gulf States, which also did everything else: billing, engineering, etc. It was claimed that independent operation would increase costs by $7,800 per year, some 15 per cent of operating revenues. The Commission said that it was not clear that this met the "A" requirements, since the city of Jasper had built a municipal plant in 1941 and had taken away one-fourth of Jasper's business in five months. In view of the competition, the Commission had doubts "as to whether any economies accrue from being in the system," and whether the alleged loss of economies would be obviated by acquisition by the city. The question was left open for further evidence if Gulf were to be chosen as the main system.

One of the severest critics of the Commission's administration of the Act has this to say concerning the decision on the Alvin property:

> It is characteristic of the Commission that it did not suggest positive action of sale by Gulf States to Houston of the Alvin, Texas, utility assets--in view of the facts, a logical and constructive move.[1]

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[1] Klingman, op. cit.

Perhaps a logical and constructive move, but one which the Commission had no legal right to take, and one which seems quite unnecessary, in view of the circumstances, since there was only one logical buyer for this property, which Gulf States was under orders to divest. Actually, since Gulf States did not remain a subsidiary, but became independent, it would have retained the property, if it had so desired. However, it sold the property in October, 1950.[1] There is no record of who bought it, but evidently either Houston or the municipality did so.

The question of whether Jasper was retainable under clause (A) became moot when Engineers decided to divest all the subsidiaries. Gulf States apparently sold Jasper in 1949; the buyer is not determinable.[2]

The common stocks of El Paso, Gulf States and Virginia were all distributed as liquidating dividends in 1947.[3] Puget Sound, whose preferred stock was in arrears, was reorganized, and in 1943 Engineers disposed of the 3 per cent of the common stock it received. Key West was sold to that city in 1943. The Nebraska and South Dakota properties of Western Public Service were acquired by the state of Nebraska's public power

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[1] Moody's Manual, 1951.

[2] Compare Gulf States in Moody's Manual, 1948 and 1949.

[3] Holding Company Act Releases 7041, 7119.

interests in January, 1942, with a new company of the same name taking over the Wyoming properties.[1] In 1946, this company was sold privately,[2] as were Missouri Service Company and Northern Kansas Power Company,[3] and Savannah[4] in 1945.

Before Engineers was liquidated, Virginia received the approval of the Commission to acquire the stock of Virginia Public Service Company,[5] a subsidiary of Associated Gas and Electric Company, which was under Section 11 (b) (1) orders to dispose of it.[6] Public Service's service areas were in two parts, one contiguous to Virginia's on the west, the other, on the east. The two parts were connected only through Virginia's lines. The population of Public Service's areas totaled about 600,000. In 1943, its total electric operating revenues were 13.3 million dollars, compared to 21 million dollars in that year for Virginia.[7] No other information is given, the Commission merely stating that it had:

examined the geographic and operational aspects of the

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[1] Holding Company Act Release 3245.

[2] Holding Company Act Release 6420.

[3] Holding Company Act Release 5844.

[4] Holding Company Act Release 5738.

[5] Holding Company Act Release 5021, May 1, 1944.

[6] See above, p. 44.

[7] Statistics, 1943.

acquisition sufficiently to be satisfied that the acquisition will tend toward the efficient and economical development of an integrated public utility system.

It was intended to merge the properties, and the merger had been approved by the State Corporation Commission of Virginia, and hence, the acquisition of the assets as such was exempt from the provisions of Section 10 (by Section 9 (b) (1)).

Analysis

There could have been no loss of plant economies, since there was no separation of interconnected operating properties. Gains can be anticipated in the case of Virginia Electric and Power's acquisition of Virginia Public Service Company, although there is nothing in the record to show their magnitude. Acquisition of the Nebraska properties by public power districts there should have the same results.

Losses in firm economies were claimed by Engineers. In the cases cited, they were negligible for Gulf States and Virginia, and on the order of magnitude of 1 per cent of gross electric operating revenues for El Paso and Savannah. But it must be remembered that these were not claimed as a result of separation from the system, but only upon separation from another company. The total losses would presumably be larger, not only for the companies named, but for the other former subsidiaries. Such claims presumably were not made because the subsidiaries could not be retained on other grounds; i.e.,

the Commission's single area interpretation of clause (B). Hence, it seems desirable to investigate the effects of separation on firm costs (administrative and general expenses) for those companies for which data are available. Table 11 contains this information.

TABLE 11

DIVESTED SUBSIDIARIES OF ENGINEERS PUBLIC SERVICE COMPANY
Administrative and General Expenses (Excluding the Pension Account) as a Percentage of Gross Electric Operating Revenue

Year	Savannah Electric & Power	El Paso Electric	Gulf States Utilities	Virginia Electric[a,b]	Puget Sound[c]	Western Public Service[d]
1938	5.4	6.0	4.9	5.8	6.6	---
1939	5.1	6.0	5.0	5.2	7.8	---
1940	4.6	6.0	5.1	5.2	10.1	---
1941	4.0	5.3	4.7	4.3	8.2	---
1942	4.4	6.0	4.8	4.2	8.4	8.9
1943	3.7	5.6	4.2	3.8	8.5[e]	7.9
1944	3.6	3.6	4.0	3.9	6.8	6.1
1945	5.0[e]	4.5	4.1	4.6	6.6	7.2
1946	7.2	5.1	4.4	4.3	5.9	6.2[e]
1947	6.4	5.8[e]	5.1[e]	3.7[e]	6.1	5.9
1948	5.8	6.1	4.8	3.0	7.0	5.9
1949	5.7	5.8	5.7	2.9	7.4	5.6
1940	5.8	6.0	5.4	3.2	8.5	5.4

[a] Including Virginia Public Service Company from May 25, 1944, date of acquisition. Data adjusted to include Public Service in previous years.

[b] Acquired East Coast Electric Company on December 31, 1949.

[c] Part of properties acquired by Washington Public Utility District on September 1, 1949.

[d] Company began operations on January 3, 1942, taking over Wyoming properties formerly owned by Western Public Service Corporation (Maryland).

[e] Year divested.

The averages of the periods before and after separation, are as follows: Savannah, 4.4 per cent and 6.0 per cent, an increase of 27 per cent; El Paso, 5.3 per cent and 6.0 per cent, an increase of 12 per cent; Gulf States, 4.6 per cent and 5.3 per cent, an increase of 13 per cent; Virginia, 4.6 per cent and 3.0 per cent, a decline of 35 per cent; Puget Sound, 8.2 per cent and 6.9 per cent, a decline of 16 per cent; Western Public Service, 7.5 per cent and 5.7 per cent, a decline of 24 per cent.

Some circumstances peculiar to particular companies should be noted. Western Public Service, a very small company after reorganization, was sold privately to an individual who is apparently managing the firm himself. Just as in the case of New Mexico Electric Service (a former subsidiary of Electric Bond and Share),[1] this personal management by the owner of a small company has apparently resulted in a decline in management costs, at least after the first year of independent ownership. Savannah was bought privately, apparently as an investment, by the trustees of an estate, and that company has evidently been managed by an independent management company. The management and supervision fees and expenses account has been consistently much higher since separation than when the subsidiary paid Engineers on the same account. It should be noted that none of the now independent

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[1] See above, pp. 136 and 144.

companies, with the exception of Savannah, use independent service companies regularly.

Comparing the changes in these firm costs with the national average of changes,[1] indicates that three of the former subsidiaries have lost firm economies, while the other three have gained, all in a very marked pattern. Thus, the data do not show a general increase in firm costs for these companies.

The Middle West Corporation

As of December 31, 1938, the electric subsidiaries of the old Insull holdings served an aggregate population of about 4 million in 16 states (see map).[2] However, not all of these properties were dealt with under Section 11 (b) (1). In 1940, Midland United Company and the sub-holding companies, Midland Utilities, Commonwealth Light and Power Company, and Inland Power and Light Company, were dismissed as parties to the hearings, since they were being reorganized under Section 77 B of the Bankruptcy Act, and the Commission felt it was unlikely that it would be necessary "to issue any order in this proceeding directing such parties to take any action pursuant to 11 (b)."[3] This action eliminated all of the

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[1] See Appendix.

[2] Holding Company Act Release 1950.

[3] Holding Company Act Release 2137.

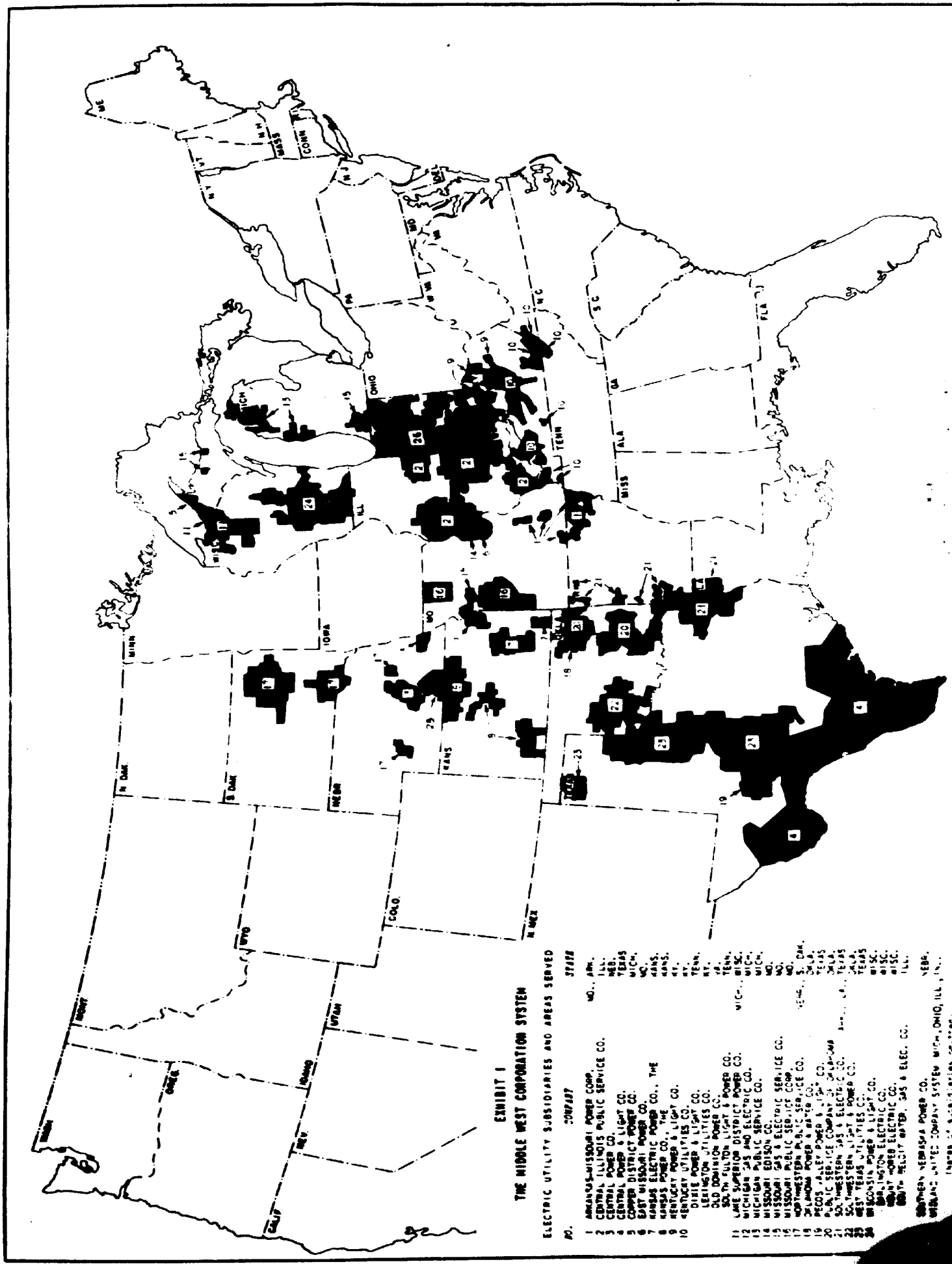

EXHIBIT I

THE MIDDLE WEST CORPORATION SYSTEM

ELECTRIC UTILITY SUBSIDIARIES AND AREAS SERVED

NO.	COMPANY	STATE
1	ARKANSAS-MISSOURI POWER CORP.	MO., ARK.
2	CENTRAL ILLINOIS PUBLIC SERVICE CO.	ILL.
3	CENTRAL POWER CO.	NEB.
4	CENTRAL POWER & LIGHT CO.	TEXAS
5	COPPER DISTRICT POWER CO.	MICH.
6	EAST MISSOURI POWER CO.	MO.
7	KANSAS ELECTRIC POWER CO., THE	KANS.
8	KANSAS POWER CO., THE	KANS.
9	KENTUCKY POWER & LIGHT CO.	KY.
10	KENTUCKY UTILITIES CO.	KY.
	DIXIE POWER & LIGHT CO.	TENN.
	LEXINGTON UTILITIES CO.	KY.
	OLD DOMINION POWER CO.	VA.
11	SOUTH FULTON LIGHT & POWER CO.	TENN.
12	LAKE SUPERIOR DISTRICT POWER CO.	WISC., MICH.
13	MICHIGAN GAS AND ELECTRIC CO.	MICH.
14	MICHIGAN PUBLIC SERVICE CO.	MICH.
15	MISSOURI EDISON CO.	MO.
16	MISSOURI GAS & ELECTRIC SERVICE CO.	MO.
17	MISSOURI PUBLIC SERVICE CORP.	MO.
18	NORTHWESTERN PUBLIC SERVICE CO.	NEBR., S. DAK.
19	OKLAHOMA POWER & WATER CO.	OKLA., TEXAS
20	PECOS VALLEY POWER & LIGHT CO.	TEXAS
21	PUBLIC SERVICE COMPANY OF OKLAHOMA	OKLA.
22	SOUTHWESTERN GAS & ELECTRIC CO.	OKLA., TEXAS
23	SOUTHWESTERN LIGHT & POWER CO.	OKLA.
24	WEST TEXAS UTILITIES CO.	TEXAS
25	WISCONSIN POWER & LIGHT CO.	WISC.
26	WISCONSIN ELECTRIC CO.	WISC.
27	BURLINGTON ELECTRIC CO.	WISC.
28	EAST MOLINE ELECTRIC CO.	WISC.
29	ROCK ISLAND WATER, GAS & ELEC. CO.	ILL.
30	SOUTHERN NEBRASKA POWER CO.	NEBR.
31	MIDLAND UNITED COMPANY SYSTEM	MICH., OHIO, ILL., IN.

Indiana properties from consideration.

The first Section 11 (b) (1) decision concerning this system was promulgated in January, 1944.[1] During the course of hearings, the system claimed that there were two major integrated systems, one containing the Illinois and Kentucky properties (with Wisconsin Power and Light Company retainable as an additional system) and the crescent shaped group of properties running through Texas, Oklahoma, and Louisiana, which were mostly controlled by a sub-holding company, Central and Southwest. The other (scattered) properties were not claimed retainable. The properties will be discussed in this order.

The two northern properties claimed an integrated system were Central Illinois Public Service Company and Kentucky Utilities Company. Their combined book electric plant account was about 125 1/2 million dollars at the end of 1940, and their electric revenues for that year totaled 23 1/2 million dollars. As the map shows, the Central Illinois properties were in four generally separate areas. They all were interconnected by lines running into the southeast area. The main generators were in the south and southeast areas, and power was supplied to the western and northeastern areas, although these two areas also purchased from other sources. The record does not show the amounts of interchange.

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[1] Holding Company Act Release 4846.

The southern generating plants were connected with the western service area of Kentucky. The remainder of Kentucky's service areas were neither contiguous with, nor interconnected with, the western portion. Each portion of Kentucky had generating facilities, and the western portion was tied to TVA, while the eastern group purchased power from Louisville Gas and Electric Company at Louisville via a line owned by Kentucky.

Much testimony was given in regard to a proposed interconnection of the Kentucky service areas, in order to meet the "capable of interconnection" requirements of the Act, but the Commission did not reach a decision at this time. The reason given was that the Indiana properties (subsidiaries of Midland United) were contiguous with those of Central Illinois and Kentucky, and the Commission felt it possible that Middle West might acquire "substantial" holdings of these properties upon the reorganization of Midland. This would result in a larger group of properties for consideration under Section 11 (b) (1).

> Different components may be regarded as desirable: different operating relationships may exist. We believe it fair to correspondents to reserve jurisdiction as to the Northern properties until the reorganization issues are decided, and the maximum units of Middle West properties which may be the subject of consideration have been determined.

In discussing the Illinois-Kentucky properties, the Commission did conclude that there was a maximum of two integrated systems, the Illinois-western Kentucky group, and the

eastern Kentucky group. It concluded that the whole territory served was quite homogeneous, being devoted primarily to agriculture and mining, and that the population centers served were generally quite small. Thus, the Commission appeared not unsympathetic to the claim that the whole area was a single integrated system, although the question was left in abeyance.

The Commission did not find Wisconsin Power and Light Company to be a retainable additional system with the northern properties. The company, which was internally integrated, was about 125 miles from the nearest Illinois property. The only evidence presented to meet the requirements of clause (A) concerned firm economies--servicing by the Middle West service companies.[1] These companies serviced the whole Middle West system, but not Midland United properties. In addition to the more usual services--accounting, advertising, engineering and operations, legal, etc.--a mutual insurance and safety program was also included.

It was testified that if services were limited to the northern and southwestern groups, the service companies' efficiency of operation would not be impaired, and the same savings as before would be realized. Since, even if both the northern and the southwestern systems were found to be

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[1] They were: Middle West Service Company, Illinois Stock Transfer Company, Bureau of Safety and the Insurance Trust Fund.

integrated systems, they both could not be retained under common control because of clause (B). The question which the Commission studied here was how much Wisconsin would lose if it were separated from the northern properties alone. P. L. Smith, president of Middle West and chairman of the board of Middle West Service Company, estimated that the charges of the latter company, if it served only the northern properties, would be "twenty-five to fifty percent higher than those at present." It was also testified that it might be feasible to have a system insurance plan for just the northern properties, instead of for the whole system, but that the amount of savings for each company would be materially less, as compared with each company doing the same thing separately.

The Commission stated that, to the extent that dollar values had been put on them, net savings alleged to accrue to the northern group of properties from their use of system service companies totaled about $411,500 per year. As pointed out above, this much saving would not accrue to them as a group separate from the rest of the properties, so the Commission adjusted service charges upward by one-third, which would give the northern properties total savings of $341,000 as opposed to each company supplying itself with the same services. For Wisconsin, the company under discussion, the figure would be $128,000, or 1.3 per cent of gross operating revenue, which would thus be the amount that costs were expected to increase

upon separation from the other northern properties.[1]

The Commission thought that this amount of savings did not meet the requirements of clause (A), and further said that to offset the savings from retention of Wisconsin would be the cost, in terms of administrative expense and taxes, for the additional corporate entity necessary for common control. Also noted was the fact that independent service companies might give the same benefits to an independent Wisconsin.

The southwestern group of properties presented what was said to be the most complex integration question ever brought before the Commission. The five companies claimed to be an integrated system were: Central Power and Light Company, West Texas Utilities Company (including Pecos Valley Power and Light Company, adjacent to and integrated with it, and which it absorbed during the course of the hearings), Southwestern Light and Power Company (the assets of which were later acquired by its parent, Public Service Company of Oklahoma), Public Service Company of Oklahoma (including Oklahoma Power and Water Company, a direct subsidiary of Middle West, which adjoined and was interconnected with it and which was later absorbed by it) and Southwestern Gas and Electric Company. The aggregate book value of utility plant

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[1] For the other northern properties--Central Illinois, Kentucky and Lake Superior District Power--the percentages ranged from .35 per cent to 1.9 per cent.

totaled 150 million dollars in 1941, and gross electric revenues for that year were about 30 million dollars. All five of the companies were interconnected by system owned lines. All generators were operated synchronously (same voltage, frequency and phase) and a central load dispatching office was planned at Tulsa. The record is not entirely clear,[1] but the following seem to be the facts concerning the actual and anticipated coordination of facilities within the system at the time of this decision.

Central Power and West Texas were tied by two 66 kv. lines. After 1930, when Central Power built a generating plant in the western part of its system, the connections were used only for emergency and stand-by purposes and to balance power sent by West Texas to a small adjacent area of Central Power. The highest yearly exchange (1939) was about 3 1/2 million kwh. In a normal year, Central Power bought around 35 million kwh. from San Antonio Public Service, a non-affiliate. Until the building of a new plant at Corpus Christi, power from the western plant flowed east and south over long lines, with consequent high line losses. Base loading of the east and south portions of Central Power's service area from the new plant, in order to utilize it fully,

[1] For example, in one part of the decision, it was stated that Central Power was "estimated to have demand in excess of capacity and firm purchases," while elsewhere it was said that an increase in capacity of a plant at Corpus Christi and a decrease in the load in the western part of its services area "gave it excess generating capacity."

together with a decline in load in the western part of the territory, would allow energy from the western plant to flow north into West Texas to increase the supply there in order to meet increasing demand without building new capacity, and in addition would allow the removal of a high cost plant from base loading. In addition, there was substantial peak diversity in the two companies because of "geophysical differences and consequent differences in the timing of agricultural load demands." On the basis of studies made by Central Power and West Texas, it seemed desirable for the latter to cut down power flow to Southwestern Light and Power Company from its northernmost generator, and to send that power south into West Texas. This would enable the Abilene plant (in the central portion of West Texas' system) "to carry the load in the central area more easily and would give a stability to the system not then existing." The Commission went on to say:

> .... the construction of a new unit [in the north] would not have enabled the postponement of new units elsewhere to take care of the increasing load in the West Texas system because the station was too far removed from the load center at Abilene and the lines from [the north] to Abilene were not adequate to carry added capacity.

The importance of this conclusion will become apparent in the discussion of Southwestern.

Southwestern Light and Power was tied to West Texas by two lines (one 33 kv. and one 66 kv.). From 1930 to 1940, West Texas supplied Southwestern Light and Power with about

60 per cent of its energy requirements, approximately 40 million kwh. per year. Due to increased demand, more energy was needed by Southwestern Light and Power, and there were three possible sources for it. Southwestern Light and Power could build new capacity, it could get it from Public Service of Oklahoma, which had low fuel cost generators and substantial excess capacity, or it could get it from West Texas, if it could persuade West Texas to supply it. This could only be done if West Texas would build additional capacity at its northern plant. In fact, according to the Commission, Southwestern Light and Power could not keep up its purchases from West Texas at past levels unless this were done. Even if West Texas could be persuaded to build the plant, the Commission thought it would be unwise:

> The addition would cost as much as would a plant built by Southwestern Light itself; the 66 kv. line from [West Texas' northern generator] to [Southwestern Light and Power] would need supplementing because it was inadequate to take anything over 8,000 kw.; the additional line would traverse the same territory as the one in existence and would be subject to the same weather hazards; and finally, the plant was remote from the center of the Southwestern Light load which is near Chickasha. The other two possibilities were, from an operating standpoint, much to be preferred since they brought power directly to Chickasha, the center of the load, did not cover the same territory already covered by the line from [West Texas to Southwestern Light and Power], and permitted more adequate operational regulation.

If Southwestern Light and Power were to build its own capacity, or obtain it from Public Service, it was forecast that purchases from West Texas would drop off. In the former

case, it was thought that the firm power contract with West Texas would be terminated; in the latter case, purchases by 1949 were expected to aggregate only 20 million kwh. and perhaps much less. Thus, it was said, the tie with West Texas was to be used only for stand-by and emergency.

On this basis, the Commission tentatively concluded that there was, or would be, an operational gap between West Texas and Southwestern Light and Power. That is, there would be little operational relation between them and hence no need for common control. Thus, West Texas and Central Power were determined to be one integrated system, and it was also tentatively concluded that the other three companies--Southwestern Light and Power, Public Service of Oklahoma, and Southwestern Gas and Electric--were another integrated system.

On the basis of system studies referred to above, the system decided that the most economical way to supply power to Southwestern Light and Power was by connecting it with Public Service of Oklahoma. Consequently, in 1941, a 132 kv. transmission line between the two properties was built.

Not only did Public Service have excess capacity in its low fuel-cost generators--in 1940 its assured station capacity in its main system was 73,000 kw. compared to peak demand of 57,000 kw.--but it could also draw 25,000 kw. of firm power from the Grand River Dam Authority project, located about 20 miles from Tulsa.

Southwestern Gas, the fifth company in the chain, was also in need of additional power. It had been buying the bulk of its power requirements from a non-affiliate, Texas Power and Light Company, and only one of its plants had been generating a sizeable amount of energy, because of high costs. As a result of system studies made, evidently, in connection with this case, a 132 kv. line was completed in 1942 connecting it with Public Service. The tie assured Southwestern Gas of 25,000 kw. of additional firm capacity, and hence eliminated the need for building new capacity. It was also to be used for the flow of economy power. The tie seemed more desirable, in any event, than building new capacity in Southwestern Gas' territory, since a good part of its load was in supplying the oil industry. It was pointed out by the Commission that this business is particularly susceptible to fluctuations. Thus, capital outlay for a new generating plant would be risky, and, to the extent it obviated building local capacity, the interconnection acted as "insurance against financial uncertainty."

The Commission felt that savings to these three companies, due to interconnection and coordination of facilities, would amount to $4,500,000 for the period 1942-1950. Thus would result mainly from savings in plant construction due to ability to delay it and also because of peak load diversity among the companies. In addition, it would result "in some measure" from elimination of "labor and other constant costs."

Included in the record is a comparison of cost of plant additions under independent operations of the three companies and costs under interconnected operation. Between 1941 and 1950, $10,080,000 in new generating capacity would have to be built by the companies as independents, while, operating as a unit, $2,373,000 in interconnections would be required (actually built in 1941-1942) along with $2,414,000 of new capacity, or a total of $4,787,000. The capital savings alone for the longer period 1941-1950 would thus be $5,293,000. It was on this basis, of course, that the Commission determined these three properties met the requirements of the Act.

Even though the Commission tentatively concluded that there were two integrated systems in this group of properties, on the basis of the "operating gap" between West Texas and Southwestern Light and Power, it gave the system further time to place additional evidence in the record, since Middle West had argued that the group as a whole met the requirements of the Act, while the staff of the Public Utilities Division had argued that there were at least five separate integrated systems in the area.[1] This was permitted even though the Commission had difficulty in this decision finding that the West Texas-Central system alone met the geographic requirements of the Act because of its size.

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[1] Each company was a separate system, it was argued by the Division, since interchange agreements were all by contract and the service areas were, in large part, separated.

In February, 1945, on the basis of the new evidence offered by the system, the Commission changed its mind and determined the whole group to be a single integrated system.[1] The new evidence demonstrated to the satisfaction of the Commission that, at the time of the decision, substantial operating coordination existed between the two groups, as well as between the companies in each group.

> .... this coordination is essential to the internal operations of all companies in both systems, and .... [contrary to indications in the prior record] there will not be a substantial future decrease in the operational coordination between the systems and in resulting economies.

The "operating gap" had failed to materialize. The earlier forecast of declining sales between West Texas and Southwestern Light and Power (now part of Public Service) was incorrect. For the years 1943 and 1944,[2] sales exceeded the forecast by approximately 10 million kwh. The data included in the decision showed a single month's power interchange between the companies in the system (excluding regular contract commitments), which demonstrated to the satisfaction of the Commission the heavy power interchange between West Texas and Southwestern Light and Power (which, as noted above, had been absorbed by its parent, Public Service). The relevant information is shown in the following table.

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[1] Holding Company Act Release 5606.

[2] The last seven months are estimated.

TABLE 12

ECONOMY INTERCHANGE OF ENERGY IN MIDDLE WEST'S SOUTHWESTERN GROUP FOR ONE MONTH (IN THOUSANDS OF KWH)

Company Originating Energy	Company Receiving Energy			
	Central	West Texas	Public Service	Southwestern Gas
Central	--	707.0	--	--
West Texas	7.6	--	646.0	--
Public Service	--	406.9	--	714.6
Southwestern Gas	--	--	702.1[a]	--

[a] This interchange was possible because Southwestern Gas was still purchasing large quantities from a non-affiliate (from Statistics, 1944-1945).

The increase in economy interchange was due in large part, no doubt, to the installation of a central load dispatcher, who worked in conjunction with committees from each of the system companies.

> He has the entire generating system under his control and he can coordinate the facilities so as to route power from place to place within the system as need and economy dictate.

The decision of the Commission involved judgment of future, as well as analysis of past, conditions. Its finding was based, of course, on the then present indications. It pointed out that if circumstances changed, it would have the power to take "proper action" as long as Central and Southwest (the sub-holding company over these properties) remained a holding company, even though it were to be separated from Middle West. No additional action has ever been taken.

No final decision on an integrated system in the northern properties was ever reached. Middle West did, in fact, receive large blocks of the common stock of Public Service Company of Indiana and Northern Indiana Public Service Company upon the completion of Section 77 B proceedings against Midland United, and Section 11 (b) (1) hearings concerning the northern properties of Middle West were reconvened. However, they were suspended in 1946 upon the request of Middle West. In the next year, Middle West's stockholders agreed to dissolution. The stocks of Central and Southwest Corporation (the sub-holding company heading the integrated southwestern system), Central Illinois, Wisconsin, Kentucky, Public Service of Indiana and Northern Indiana Public Service Company were distributed as liquidating dividends in 1947-1949.[1] Distribution of the remaining assets, principally cash, and dissolution of Middle West was approved in May, 1950.[2] The stocks of Lake Superior, Michigan Gas and Electric, and Upper Peninsula Power were sold publicly.[3] The remaining properties were sold privately. The Central Power Company was sold to the Nebraska Public Power District in 1941.[4] Missouri Edison Company and East Missouri Power

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[1] Holding Company Act Releases 6786, 7272, 7352, 7486, 7986, 8642, 8788.

[2] Holding Company Act Release 9867.

[3] Holding Company Act Releases 5845, 6815, 7322, 9260.

[4] Holding Company Act Release 2471.

Company (a subsidiary of Arkansas-Missouri Power Corporation) were sold to one private buyer (the Commission having found previously that together they were an integrated system.[1] Arkansas-Missouri itself was sold to another individual who operated other properties in the area under long-term leases.[2] The main service area of Arkansas-Missouri was interconnected with these three by the lines of Arkansas Power and Light Company, a non-affiliate. The Commission found that this sale met the requirements of Section 10 (c) (2).[3] Midwest's stock holdings in the Copper District Power Company were sold to Upper Peninsula Power Company.[4] Upper Peninsula, as part of the Consolidated Gas and Electric Company's system remained under the Act.[5] Kansas Electric Power Company was

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[1] Holding Company Act Releases 5845, 4846.

[2] These companies were: Arkansas General Utilities Company, Citizens Electric Company, and Arkansas Utilities Company.

[3] Holding Company Act Release 5845.

[4] Holding Company Act Release 7407.

[5] The stock of Copper District had been owned by Middle West and Copper Range Company. In 1947, the new corporation, Upper Peninsula, was organized by Middle West, Copper Range and Consolidated Electric and Gas Company (which had three operating subsidiaries in the Upper Peninsula of Michigan) to acquire the assets of all these operating companies. Consolidated Electric and Gas, a registered holding company which controlled only 7 scattered electric properties, was itself a subsidiary of Consolidated Public Utilities Corporation. Both companies were in dire financial straits, with income bonds and preferred stock in arrears. They voluntarily planned to recapitalize, wiping out the common stockholders, and then liquidate. The Commission

sold to Kansas Power and Light Company, a former subsidiary of the North American Company. Kansas Power Company was sold to Western Light and Telephone Company.[1] The year after acquisition--1944--it was merged into Western. One other former Insull holding, Indiana Service Corporation, a subsidiary of Midland Realization Company, was sold to a subsidiary of American Gas and Electric Company, itself a former subsidiary of Electric Bond and Share.[2]

The Middle West Service Companies, which had for some years provided service to present and former subsidiaries on an "as and when ordered" basis, remained in existence, since Middle West transferred its interest in them to certain officers and employees of those companies. Practically all former subsidiaries (except, of course, those companies now part of other systems) still utilize the services of these companies.[3]

Analysis

No order of the Commission could have resulted in loss of plant economies, since no interconnected subsidiaries were

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never took Section 11 (b) (1) action against them. For more details, see Holding Company Act Release 3225 and Moody's Manual, 1947-1951.

[1] Holding Company Act Release 4998.

[2] See above, pp. 110-112.

[3] Moody's Manual, 1950, 1951.

required to be separated. While it is true that the various Illinois, Indiana, and Kentucky companies, some of which were interconnected, became independent of each other, this was done entirely voluntarily by the owners. On the basis of the record, it seems doubtful that the Commission would have required separation of any interconnected property there, so it is hardly conceivable that Commission pressure could have contributed to the decision to separate. The decisions on the southwestern group of properties would seem to demonstrate the extreme care on the part of the Commission not to cause loss of plant economies.

The acquisition of many of the scattered properties by contiguous operating or holding companies should result in plant economies. While only one of these sales was a case in which anticipated economies are noted,[1] the discussion in Chapter II would indicate some savings in all such cases.

Middle West anticipated loss of firm economies upon break-up of the system, due to the fact that the independents would have to do the jobs formerly done by the system service companies. As a matter of fact, the service companies, now independent, have continuously serviced the great majority of the former subsidiaries, including the system of Central and Southwest. On this basis, it is not clear that there should be any loss of firm economies. However, it seemed

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[1] See above, pp. 110-112.

desirable to investigate the results of separation upon administrative and general expenses. Table 13 contains the relevant data on those companies for which it is available.

Averaging these figures gives the following results for each company (the first figure is the average of administrative and general expenses as a percentage of gross electric operating revenue for the years as a subsidiary, and the second figure for the years as an independent): Central Illinois Public Service Company, 5.3 per cent and 4.3 per cent, a 19 per cent decline; Kansas Power Company, 8.0 and 6.7 per cent, a 16 per cent decline; Kentucky Utilities Company, 5.9 per cent and 4.5 per cent, a 24 per cent decline; Michigan Gas and Electric Company, 5.4 per cent and 6.2 per cent, a 13 per cent increase; Arkansas-Missouri Power Corporation, 7.3 per cent and 6.5 per cent, an 11 per cent decline; Missouri Gas and Electric Service Company, 7.8 per cent and 5.7 per cent, a 27 per cent decline; Lake Superior District Power Company, 7.4 per cent and 6.5 per cent, a 12 per cent decline; Wisconsin Power and Light Company, 5.1 per cent and 4.7 per cent, an 8 per cent decline; Public Service of Oklahoma, 5.6 per cent and 7.1 per cent; Central Power and Light Company, 7.4 per cent and 7.7 per cent; Southwestern Gas and Electric Company, 5.2 per cent and 5.3 per cent; West Texas Utilities Company, 7.4 per cent and 5.8 per cent. For the latter four companies, which comprise the Central and Southwest holding company system, the combined averages are 6.4 per cent before

TABLE 13

DIVESTED SUBSIDIARIES OF THE MIDDLE WEST CORPORATION
Administrative and General Expenses (Excluding the Pension Account) as a Percentage of Gross Electric Operating Revenue

Year	Central Illinois Public Service Co.	Kansas Power Co.	Kentucky Utilities Company	Michigan Gas and Electric Company	Arkansas-Missouri Power Corporation	Missouri Gas and Electric Service Corporation	Lake Superior District Power Co.	Wisconsin Power and Light Company	Public Service Co. of Oklahoma[a]	Central Power and Light Company[a]	Southwestern Gas and Electric Co.[a]	West Texas Utilities Co.[a]
1938	7.0	8.8	4.8	6.4	8.7	9.2	7.1	5.8	5.0	6.9	5.0	c
1939	6.5	8.0	5.5	5.4	7.9	8.8	7.9	5.5	5.4	7.7	5.5	
1940	5.8	8.0	6.3	5.7	7.3	6.8	7.5	5.3	5.3	7.4	5.4	
1941	5.3	7.7	6.2	5.1	7.3	7.0	7.2	4.9	5.3	7.6	5.2	
1942	5.4	8.3	6.3	5.6	6.9	7.0	7.9	5.3	5.0	8.0	5.1	
1943	5.0	7.4	6.1	5.1	7.2	7.5[d]	7.1	5.0	4.9	7.7	5.3	
1944	4.8	6.7[d]	6.1	4.8	5.5	6.7	6.9	4.9	5.4	7.2	5.1	6.9
1945	4.7	b	6.0	4.5	5.1[d]	5.7	6.5[d]	4.7	6.5	7.0	5.7	7.4
1946	4.6		6.5	5.6	5.5	6.5	7.7	4.7	7.9	7.4	4.1	7.9
1947	4.2		5.6	6.1[d]	7.2	5.2	7.0	5.1	7.7[d]	6.2[d]	5.4[d]	7.9[d]
1948	4.5[d]		5.4	6.5	6.8	5.0	5.9	4.9[d]	7.5	7.8	5.0	6.8
1949	4.0		5.0[d]	6.1	7.1	5.5	5.9	4.7	7.3	7.8	5.4	5.5
1950	4.2		4.0	6.0	5.7	5.2	6.2	4.7	6.5	7.6	5.6	5.0

[a] Operating subsidiaries of Central and Southwest.

[b] Merged into Western Light and Telephone Company in 1945.

[c] Data not available before 1944.

[d] Year divested.

separation from Midwest, and 6.7 per cent after separation, an increase of 4 per cent.

Comparing these results with the national averages for the same periods,[1] it appears that only one of the eight former subsidiaries which did not become subsidiaries of Central and Southwest shows relative losses of firm economies. One of the eight shows relatively no change in firm economies, and the other six show gains. The present subsidiaries of Central and Southwest as a group show a marked increase in firm costs relative to the national average. These are the companies for which there should be the least anticipation of loss. It should be remembered that the system anticipated the least loss here, also.

The data certainly do not show losses to the northern companies which the system anticipated.

The North American Company

This company, organized in 1890 in New Jersey, had concentrated on electrical companies serving large population centers. Prior to 1930, it directly controlled properties serving Washington, D. C., Cleveland, St. Louis and Milwaukee. It also owned about 20 per cent of the stocks of both Detroit Edison Company and Pacific Gas and Electric Company, two of the six largest electric operating companies in the United

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[1] See Appendix.

States. Legally, both were "subsidiaries" under the Act.[1] However, North American seems never to have exercised control, in the ordinary sense of the term, over these companies, and as a matter of fact, did not claim that there would be any loss of economies upon separation. It considered the stock-holdings merely as investments.[2] In addition, North American controlled a sub-holding company, North American Light and Power Company, which controlled electric properties in Kansas, Missouri, Iowa and Illinois.[3]

Thus, in 1940, the date of the opening of Section 11 (b) (1) hearings on North American, its subsidiaries (excluding Detroit Edison and Pacific Gas and Electric) operated in nine states and the District of Columbia. Assets of these subsidiaries in that year totaled about 1 billion dollars (including gas and transportation as well as electric properties) and

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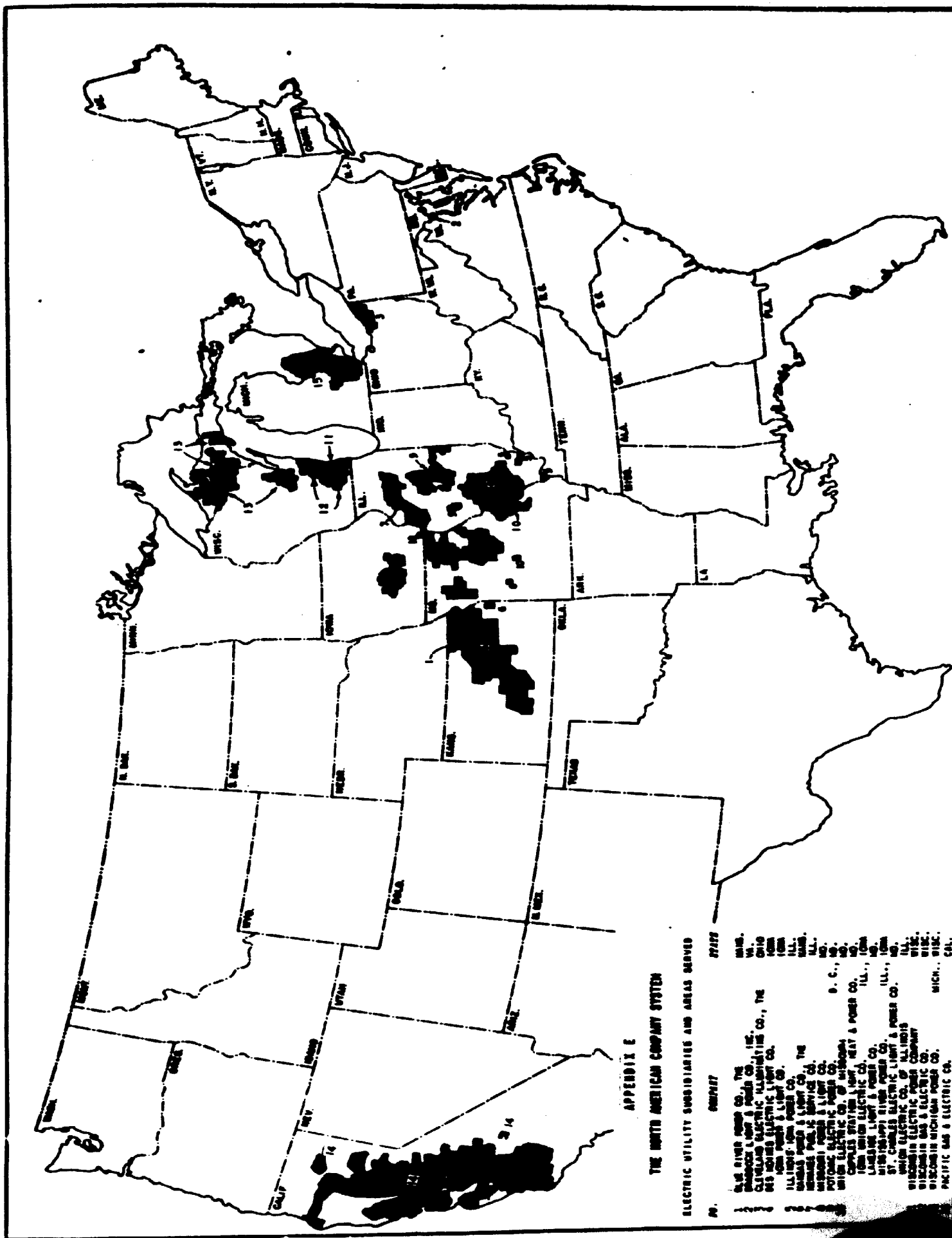
[1] Section 2 (a) (8) (A) defines subsidiaries on the basis of 10 per cent stock ownership.

[2] Holding Company Act Release 3405. North American argued that these investments were retainable under the "other business" clause of Section 11 (b) (1), which reads: "The Commission may permit as reasonably incidental, or economically necessary or appropriate to the operations of one or more integrated public-utility systems the retention of an interest in any business [other than the business of a public utility company as such] which the Commission shall find necessary or appropriate....." This claim was rejected by the Commission.

[3] In 1930, Light and Power was jointly controlled by North American and Middle West, then an Insull controlled holding company. Each owned 40 per cent of its common stock. Prior to 1940, North American acquired the bulk of Light and Power's stock. See Bonbright and Means, op. cit., p. 125.


APPENDIX E
THE NORTH AMERICAN COMPANY SYSTEM
ELECTRIC UTILITY SUBSIDIARIES AND AREAS SERVED

for that year the total electric revenues exceeded 100 million dollars.[1] Previous to the Section 11 (b) (1) decision,[2] North American Power and Light had been ordered dissolved under Section 11 (b) (2), as an undue complexity in the system.

North American had refused to choose a principal system, maintaining that the Missouri, Wisconsin and Ohio properties were all retainable together, but, according to the Commission, it indicated a preference for Union Electric Company of Missouri and its subsidiaries, and the Commission tentatively chose this as the principal system, since it served the largest market and was the most profitable of the subsidiaries.

It was conceded without argument that all of the subsidiaries, other than those which were subsidiaries of Light and Power, were individually integrated systems within the meaning of the Act. Potomac Electric Power Company, serving Washington, D. C., and surrounding portions of Maryland, had a subsidiary, Braddock Light and Power Company, serving adjacent portions of Virginia, but the separate corporate entity was for legal purposes only, and the properties were interconnected and operated as a unit. Wisconsin Electric Power Company had acquired from North American all the common stocks of Wisconsin Gas and Electric Company and Wisconsin Michigan

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[1] Holding Company Act Release 3405.

[2] Ibid.

Power Company on August 20, 1941. Although the decision does not so state, the three separate areas were tied with a 132 kv. transmission line,[1] and were presumably operated as a unit. The Cleveland, Detroit and California properties were each completely integrated corporate entities. The Union Electric Company of Missouri and its subsidiaries served St. Louis and surrounding areas in Missouri and East St. Louis and surrounding territory in Illinois. In addition, this system had two hydro plants, about one-third of its capacity, at Keokuk, Iowa, and Osage, Missouri, each of which served adjacent territory. The Keokuk plant, by far the larger of the two, was about 140 miles north of St. Louis, but all the system's producing facilities were interconnected and centrally controlled, with power flowing as necessity and economy required, without regard to corporate entities. Surprisingly, the system's steam generators were located in Illinois, although the bulk of the market was across the Mississippi River, in Missouri. This location was caused by the zone pricing of freight rates, coal costing 45 cents a ton more delivered in St. Louis than in East St. Louis.

North American presented no evidence to show whether any of the subsidiaries of its subsidiary, Light and Power, were retainable, either as a part of one of North American's

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[1] Moody's Manual, 1942.

[2] Holding Company Act Release 8625.

integrated systems or as a permissible additional system.[1] Hence, the Commission ordered North American to divest all of Light and Power's subsidiaries, although it pointed out that this did not foreclose the possibility of possible integration of any of them with the retainable properties of North American, since North American could make such requests in the future. The Commission did, however, determine that two of Light and Power's subsidiaries were integrated systems. The Iowa properties, although consisting of two separate corporate entities, one a subsidiary of the other, were completely interconnected and operated as a unit, and were determined to be an integrated system. The three main operating areas of Illinois Iowa Power Company[2] were also determined to be an integrated system, even though they were not contiguous, because they were interconnected by lines owned or leased for joint use. The four small operating areas of Illinois Iowa were held not to be a part of the main system since they admittedly were not capable of physical interconnection with the main areas, all of their power requirements being met by a non-affiliate, Central Illinois Public Service Company. Illinois Iowa argued that their operation was "thoroughly coordinated and efficiently carried on," with

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[1] As the map shows, the only problem was whether any of them might be retained with Union Electric.

[2] The name was later changed to Illinois Power Company.

respect, evidently, to management. The Commission agreed that they could not be operated as independent systems without the loss of substantial economies "which can be secured by their retention under joint control together with the principal system of Illinois Iowa ....," and hence they were all allowed to be retained by the company as additional systems. No mention was made in this case either of Missouri Power and Light Company or Kansas Power and Light Company.

The principal question raised in this decision was which, if any, additional systems might be retained together with the principal system, Union Electric. North American, as noted above, maintained that the Wisconsin and Ohio properties were retainable together with Union, relying on the "two area" interpretation of clause (B).[1] To meet the "substantial economies" requirements of clause (A), North American offered testimony which may be grouped into three general divisions: 1) assistance to subsidiaries in their financing, 2) advisory and consultative facilities, 3) benefits from its intercompany committees.

1) Assistance to subsidiaries in their financing

This was North American's most important activity in its subsidiaries' affairs. It did all the planning and handling of securities floatations. Local operating heads

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[1] See Engineers Public Service Company, above, p. 146.

disclaimed before the Commission their ability to handle this within their own groups. It was said that such talent would be expensive and that it would be wasted because of the infrequency of its exercise, if limited to individual systems. Since both the Wisconsin group and the Cleveland company had about 150 million dollars in securities outstanding in 1940, and Union Electric nearly 200 million dollars, the Commission doubted this. It thought that normal development of management, faced with finance problems as often as this, would be to become familiar with the problems. North American, it thought, may have prevented this normal occurrence from happening.

It was further argued that separation would deprive subsidiaries of an important source of financing. But North American had made no advances to its subsidiaries since 1935, according to the record. During the period 1915-1930, interest paid on up-stream loans by North American varied from 4 1/2 per cent to 8 1/8 per cent, which, the Commission stated, was generally lower than the call-money market.[1]

2) Advisory and consultative facilities

During the hearings, the subsidiaries acknowledged their indebtedness to North American for advice and consultation in regard to management matters such as budgeting,

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[1] This was called "assistance [to subsidiaries] in earning some return on that money."

accounting, tax problems and major installations. The holding company, it was claimed, held itself open for advice and consultation in order "to avoid the dangers of local stagnation." North American's entire operating division consisted of eight persons: three clerks, two engineers, one rate specialist and two executives. The Commission concluded that the record did not show that "cessation of this advice and consultation would cause the loss of substantial economies to the subsidiary systems." In addition, one of North American's witnesses said that "in the electrical industry as a whole .... there is a great freedom of interchange of ideas, facilities and information." Thus, the Commission said:

> We may assume that the character of the electric industry will not change so drastically in the future as to permit companies which have been severed from the North American system to fall into a "local stagnation."

3. Intercompany committees

The North American subsidiaries, excluding Light and Power subsidiaries and Pacific Gas and Electric, were all represented on three system committees which served as a clearing house within the system for technical and accounting information. According to the Commission, the record indicated that the committees had been of some benefit to the participating companies. Witnesses who testified to the value of these committees also said that they could not survive a rupture in the affiliated status of the companies. The Commission could not understand this--

> .... if the value of the committees is so patent, the self-interest of the particular companies would compel their retention. We see no obstacle to the retention of such committees outside the North American system, and we think their dissolution would only be proof of the insubstantiality of the "economies" resulting from them.

Thus, the Commission did not find that clause (A) was met. In addition, the single area interpretation of clause (B) would bar the retention of all but the Wisconsin group (except for the Power and Light subsidiaries), and the Commission felt that such retention would be barred under clause (C). Hence, North American was ordered to dispose of all its subsidiaries except Union Electric Company.

North American challenged the validity of the Commission's decision in the courts. As noted above, it wished to keep the Wisconsin and Cleveland properties, together with Union Electric. The Circuit Court of Appeals for the Second Circuit upheld the Commission's decision in its entirety,[1] whereupon the company carried the case to the Supreme Court, on writ of certiorari, on the grounds that Section 11 (b) (1) was unconstitutional.[2] It argued that Congress had no jurisdiction, since ownership of stock was not commerce, and that the order constituted deprivation of property without due process of law.

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[1] North American Co. v. S.E.C., 133 F. 2d 148 (1943).

[2] 327 U.S. 686 (1946).

The Supreme Court determined that North American was more than an investment company in that its holdings of stock were such as to make domination over its subsidiaries possible, even if that power were seldom exercised. It had been found that operations and operational policies had been left to local managements, and the holding company had not sold any "supplies or engineering services" to the subsidiaries. However, it had supplied services,[1] and had thus intervened in the activities of the subsidiaries. North American held large amounts of its subsidiaries' securities, and there had been "penetration of local managements with men of North American background." The Court found that Section 11 (b) (1), requiring holding companies to divest themselves of certain of their holdings in specified circumstances, was within the power of the Congress to regulate interstate commerce for the purpose of eliminating an economic evil, even though ownership of securities considered "separately and abstractly" might not be commerce. The Court also found violation of due process not involved in this section, as the Act did not "contemplate or require dumping or forced liquidation of securities" and that it "protects the stockholder by requiring any plan of divestment to meet standards of fairness and equitableness." Further, the Court said

Congress has concluded from the extensive studies made

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[1] These are classified above.

> prior to the passage of the Act, that the economic advantages of a holding company at the top of an unintegrated, sprawling system are not commensurate with the resulting economic disadvantages. The reasonableness of that conclusion is one for Congress to determine. The fact that valuable interests may be affected does not, by itself, render invalid under the due process clause, the determination made by Congress.

Both the Commission's single area interpretation of clause (B) and its interpretation of clause (A) seem to have been approved by the Court:

> In essence, Section 11 (b) (1) confines the operations of each holding company system to a single integrated public utility system with the provision for the retention of additional systems only if they are relatively small, located close to the single system and unable to operate economically without the loss of substantial economies..... [Emphasis supplied.]

Thus, the constitutionality of Section 11 (b) (1) was upheld.

North American took little action in disposing of properties ordered by the Commission until after the Supreme Court's decision was handed down.[1] Thereafter, it took advantage of the Commission's statement concerning the possibility of introducing evidence to show that subsidiaries of Light and Power might be retainable with Union Electric. North American was to receive all of the common stock of Missouri Power and Light Company through the dissolution of Light and Power. It asked the Commission to find that Missouri and Union Electric were, together, an integrated system.[2]

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[1] April 1, 1946.

[2] Holding Company Act Release 8913.

The Commission's decision was forthcoming late in 1950.[1]

As the map shows, Missouri had three non-contiguous service areas in the northern part of the state. The smallest area served Clinton, Missouri. It was a distribution unit only, and all of its energy requirements were obtained from a non-affiliated company, Missouri Public Service. It was testified that it would be neither economical or practical to interconnect it with either Union Electric or Missouri. The bulk of Missouri's properties were interconnected with Union Electric at three points, and Missouri purchased at wholesale about 40 per cent of its energy requirements from Union Electric. Missouri was contiguous with the hydro property of Union Electric at Keokuk. The 35-mile break between the east and west service areas of Missouri was spanned by a transmission line interconnecting the two.

Total property and plant of the Union Electric system[2] as of June 30, 1950, was about 360 million dollars, and total electric operating revenues for the 12 months ending that date were about 66 million dollars. Comparable figures for Missouri were 28 1/2 million dollars and 6 1/2 million dollars respectively.

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[1] Holding Company Act Release 10320.

[2] All of Union Electric's former electric subsidiaries, except those operating in Illinois and Iowa, had been merged into it. The out-state properties had been merged into Union Electric of Illinois, and the name of that company was then changed to Union Electric Power Company.

It was testified by the president of Union Electric that Missouri would not be merged with it, since Missouri operated primarily in rural areas and thus faced entirely different problems than did Union Electric. However, he said that acquisition would facilitate the coordination of future energy demands, and that Missouri would obtain the benefits of the Union Electric staff with regard to engineering and other operating problems. It was said that a 60 thousand kw. transmission line, together with the necessary sub-station, could be built from Union Electric to the center of Missouri's load area for about 2 million dollars, whereas a 20 thousand kw. generating unit would cost around 4 million dollars. Also, it was testified that the acquisition would result in financial aid for Missouri, particularly in raising equity capital.

The Commission determined that the two companies, with the exception of the Clinton property of Missouri, were an integrated system, and hence the acquisition was approved under Section 10 (c) (2). The Clinton property was ordered disposed of. In June, 1951, it was sold to Missouri Public Service, the company from which it obtained all of its energy.[1]

Earlier, Union Electric had acquired the electric properties of Laclede Power and Light Company, a subsidiary of a registered holding company, the Ogden Corporation.[2]

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[1] Holding Company Act Release 10596.

[2] Holding Company Act Release 5062, May 24, 1944.

This system was disposing of scattered properties under terms of a financial reorganization through which it had gone.[1]

Laclede's service area was a portion of the city of St. Louis, and it supplied about 15 per cent of the energy used in that city. It was thus in direct competition with Union Electric, which, of course, also served St. Louis. There was a considerable amount of duplication of facilities, especially in distribution equipment. The record indicated that Laclede was faced with the need for a major reconstruction program in order to protect its load, and that a large part of this additional investment would involve further duplication of Union Electric's plant. The Missouri Public Service Commission, which had approved the sale and acquisition, had found that the transfer "should furnish an opportunity to reduce the cost of electric utility service in St. Louis," that it would enhance public safety by eliminating duplicate facilities, and that it would give the customers of Laclede better assurance of uninterrupted service, because of the diversity of the Union Electric system and its greater financial resources.[2] As will be noted below, Ogden was in no position to help Laclede to obtain capital. The Commission, of course, approved the acquisition.

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[1] See below, pp. 239-241.

[2] In the Matter of the Application of Laclede Power & Light Co. et al., case #10,263 (1943).

As early as 1943, the Des Moines and Iowa Power and Light properties of Light and Power had been sold to a subsidiary of United Light and Railways, a holding company.[1] The stock of Illinois Power Company[2] was sold publicly in 1949.[3] The stock of Cleveland Illuminated was sold in 1947, in part by the issuance of purchase warrants to stockholdings of North American and in part by sale on the open market.[4] The stocks of the remaining subsidiaries[5] were distributed to the stockholders of North American as liquidation dividends during the period 1947-1949.[6] North American itself is in the process of winding up its corporate affairs, and when it has done so, it will dissolve, leaving the Union Electric Company as its successor holding company over the Missouri-Illinois system.

Analysis

On the basis of the published record, it would appear that there could be no loss of plant economies, since the

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[1] See below, p. 276.

[2] Formerly Illinois Iowa Power Company.

[3] Holding Company Act Releases 9103, 9151.

[4] Holding Company Act Releases 7273, 7526.

[5] Potomac and subsidiary, Wisconsin Electric Power and subsidiaries, Kansas Power and Light.

[6] Holding Company Act Releases 7461, 7846, 9213, 9236.

record does not show that any interconnected properties were ordered separated. This is not true, as a matter of fact, since the southern operating area of Illinois Power (formerly Illinois Iowa Power) was interconnected with the Illinois properties of Union Electric, which supplied practically all of its energy requirements under an electric purchase contract.[1] However, the Commission was willing to allow further testimony concerning the retention of Light and Power's subsidiaries with Union Electric, and Missouri was later determined to be retainable. Since no evidence was ever introduced concerning the desirability of the retention of any part of Illinois Power with Union Electric, it may be assumed that the companies saw no advantage to such retention. In any event, the interchange contract remained in force between the two companies until at least 1951,[2] although it was anticipated that by the end of that year only a nominal amount of purchases would be made under it, since it was expected that a transmission line connecting the southern division with the generating capacity of the rest of Illinois Power would be completed by then.[3] There is no evidence that the operating relationship existing between the two companies,

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[1] Moody's Manual, 1942.

[2] Moody's Manual, 1951.

[3] The southern division had no generating capacity.

as evidenced by the interchange contract, was changed in the slightest when Illinois Power became independent. The original conclusion, that there was no loss of plant economies due to Commission action against North American, still seems valid.

There can be little doubt but that the acquisition by Union Electric of Laclede gave rise to plant economies. It is impossible to justify duplication of electric facilities. If the anticipated economies of integrating Missouri and Union Electric are realized, there may be a gain in plant economies.

The Commission has been severely criticized by Klingman for failing to agree with North American that the economies cited (in Release 3405) to meet the requirements of clause (A) were in fact "substantial":

> It is clear that SEC, rather than NAMCO [North American] regarded the economies cited by NAMCO as "not substantial"; one of the reasons for this might well have been that intangibles of this sort are not susceptible to quantitative evaluation and "statistics" often make a more convincing presentation. For anyone who had not participated in business operations of this type and had not actually witnessed some of the real gains that are often realized from this sort of set-up, it would be quite easy to dismiss them as not significant. In short, SEC was not expert enough to appreciate the significance of these factors.[1]

This criticism misses the mark. The Commission concluded that break-up of the system would not materially change the

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[1] Op. cit., p. 302.

diffusion of industry information and the possibilities of intercompany discussion of industry problems. Executives of companies affected by this decision with whom the writer has talked have indicated their belief that the Commission's decision was essentially correct in this respect. They indicate that their company's experience has been that although the same companies may not be involved, there is as much, if not more, intercompany discussion of mutual problems as there was prior to the dismantling of North American. Furthermore, the industry's trade association, the Edison Electric Institute, is very active in disseminating industry information, as are other organizations, such as the American Institute of Electrical Engineers and the Mid-West Power Conference. The Commission appears to have been expert enough to evaluate properly the factors involved.

In considering the possibilities of loss of firm economies, it would seem that less of a case was made than had been done by other systems. As Bonbright and Means said in regard to North American:

> Each of these large city properties can afford to have its own staff of engineering, financial and managerial experts, and the role of central service organizations is therefore less important than in most systems.[1]

The record would seem to bear this out. Only a modest increase in personnel would seem to be necessary for each subsidiary to perform for itself the functions previously

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[1] Op. cit., p. 125.

performed by the holding company. However, what has happened to firm costs after separation may indicate just the opposite. Table 14 shows the effects on those companies for which data are available.

The averages for the companies before and after separation are as follows: Potomac Electric Power Company, 5.0 per cent and 5.3 per cent, an increase of 6 per cent; Illinois Power Company, 3.7 per cent and 2.7 per cent, a decline of 27 per cent; Kansas Power and Light Company, 5.7 per cent and 6.8 per cent, an increase of 19 per cent; Cleveland Electric Illuminating Company, 5.0 per cent and 4.6 per cent, a decline of 8 per cent; Wisconsin Electric Power Company, 3.5 per cent and 4.0 per cent, an increase of 14 per cent; Wisconsin Gas and Electric Company, 4.7 per cent and 4.5 per cent, a decline of 4 per cent; Wisconsin Michigan Power Company, 4.9 per cent and 4.9 per cent, no change. Wisconsin Electric Power Company, the Wisconsin holding company, and its subsidiaries, Wisconsin Gas and Wisconsin Michigan, have, as a group, averages of 3.8 per cent and 4.2 per cent, an increase of 11 per cent.

Since Union Electric and its present subsidiary, Missouri Power and Light, were never separated, strictly speaking, from the system, there is no separation date and hence, no averages. However, since the bulk of the other subsidiaries were divested during 1947-1949, one of these years would seem to be the appropriate one to pick to find

TABLE 14

DIVESTED SUBSIDIARIES OF THE NORTH AMERICAN COMPANY
Administrative and Central Expenses (Excluding the Pension Account) as a Percentage of Gross Electric Operating Revenue

Year	Potomac Electric Power Company	Illinois Power Company[a]	Kansas Power and Light Company and Subsidiary[b]	Cleveland Electric Illuminating Company	Wisconsin Electric Power Company	Wisconsin Gas and Electric Company	Wisconsin Michigan Power Company	Union Electric Company of Missouri	Missouri Power and Light Company	Wisconsin Electric Power Company & Subsidiaries (Wisconsin Gas and Electric & Wisconsin Michigan) Combined
1938	5.4	4.2	5.4	5.3	---	4.3	4.5	4.0	8.6	---
1939	5.2	4.7	5.5	5.8	3.4	4.7	4.6	4.0	8.9	3.7
1940	4.9	4.4	5.3	6.4	3.3	4.7	4.4	3.9	8.1	3.6
1941	4.8	3.7	5.7	4.1	3.5	4.8	4.8	3.6	7.7	3.9
1942	5.0	3.4	5.5	4.0	3.4	4.7	5.7	4.0	8.4	3.8
1943	4.5	3.5	5.0	4.4	3.3	4.6	4.9	5.1	8.5	3.7
1944	4.6	2.9	5.0	4.9	3.2	4.6	4.9	4.4	7.7	3.6
1945	4.4	3.4	5.4	5.3	3.4	4.6	4.9	4.5[d]	7.0	3.8
1946	5.2	3.5	6.2	5.0	3.8	4.9	5.3	4.2	7.7	4.1
1947	5.5[f]	3.6	6.3	4.4[f]	4.0[f]	4.6[f]	5.1[f]	4.2	7.7	4.2[f]
1948	5.4	3.1	7.8	4.5	3.8	4.5	5.1	4.2	6.9[e]	4.1
1949	5.2	2.6[f]	7.7[f]	4.9	4.2	4.4	5.1	4.2	6.1	4.3
1950	5.3	2.7	6.8	4.5	c	c	4.5	4.0	6.1	4.2

[a] Formerly Illinois Iowa Power Company.

[b] Kansas Electric Power Company, the subsidiary of Kansas Light and Power, merged into it July 20, 1949. Therefore, data on two companies in previous years were summed to make the figures comparable.

[c] Wisconsin Gas and Electric, a subsidiary, merged into Wisconsin Electric Power on June 9, 1950, hence separate data for these companies for this year are not available.

[d] Includes Laclede Power and Light Company, acquired March 31, 1945, and Mississippi River Power Company, a subsidiary, merged May 31, 1945.

[e] Includes Gasconade Power Company, acquired December 31, 1948.

[f] Year divested.

the effect on these two companies. Using any of these years as a separation point, the combined averages of the two companies will show a decline about equal to the national average.

Comparing these percentage changes with the national averages[1] indicates that the two largest companies, Union Electric and Cleveland Electric do not show increases in firm costs, but that all of the others, with one exception, do. It should be remembered that all of these companies were divested in the period 1947-1949, and the conclusions regarding some of them, at least, should be regarded as tentative.

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[1] See Appendix.

CHAPTER IV

EFFECTS OF DIVESTITURE ON COSTS (CONTINUED)--CASES WHERE ECONOMY LOSSES WERE NOT CLAIMED

American Water Works and Electric Company, Incorporated (Now West Penn Electric Company)

This company was the first to have Section 11 (b) (1) applied to it. It submitted a voluntary (Section 11 (e)) plan to meet the requirements of Section 11 (b) in 1937, in which it asked the Commission to determine that its property met the standards of Section 2 (a) (29) (A) and hence of Section 11 (b) (1).

The Commission's decision[1] showed that total consolidated assets as of December 3, 1936, were 385 million dollars (size of electric plant is not available). Total revenue was 52 million dollars, of which more than 33 million dollars was electrical operating revenue.[2] The electric operations served the states of Pennsylvania, West Virginia, Virginia, Maryland and Ohio, an area of about 300 miles by 300 miles at its greatest extent. The area was not all interconnected and thus was not operated as a unit. In north central Pennsylvania, around Bellefonte, the service area was contiguous

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[1] Holding Company Act Release 949.

[2] Moody's Manual, 1937.

to, but not interconnected with, the main operating system. This area purchased part of its energy from a non-affiliated company. A 50-mile 132 kv. transmission line had been designed, and it was testified that it would be built (at an estimated cost of $620,000) when energy demands of the Bellefonte area warranted the expenditure. This was expected to occur in the near future. The interconnection would result in delivery of energy to Bellefonte at approximately the same cost as that of the purchased energy.

In addition, there was "a number of instances" of small independently operated areas within the main system, all of minor consequence. Some had been already tied into the main system and plans had been made to interconnect them all with it.

On this basis, the Commission concluded the entire system met the requirements of the Act and that it was therefore retainable as a unit.[1] The paucity of data and lack of critical analysis in this decision, as compared with later ones, indicate the Commission had no clear-cut formulation of policy as to what it wanted to accomplish. Furthermore, it is possible that, as Klingman argues,[2] the Commission hoped by liberal treatment in this case to entice other holding companies to submit satisfactory Section 11 (e) plans.

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[1] Holding Company Act Release 949.

[2] Op. cit., p. 143.

If this was the plan, it did not work. The Commission, recognizing the failure of a lenient policy looking toward voluntary compliance, changed its tactics in 1940 and instituted a policy of compulsory Section 11 (b) (1) actions.[1]

In 1946, during hearings on separation of all water companies from the system,[2] it was decided to eliminate the top holding company (American Water Works and Electric Company) and all intermediate holding companies, except one, West Penn Electric Company, and to make it the top company in the electric system. While not affecting firm economies as such, this action certainly reduced expenses to some extent. It seems impossible to calculate the savings, and no testimony was presented concerning them, since the company made the decision voluntarily, presumably to meet the requirements of Section 11 (b) (2) concerning "unnecessary holding companies."

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[1] "They [the holding companies] responded to the Commission's invitation by submitting tentative plans which on examination were clearly impracticable and not in conformity with the statute. In general, their plans amounted to little more than attempts to justify the retention of scattered holdings.

"It thus became clear to the Commission that compliance could be achieved only by the institution of affirmative proceedings..... Accordingly, in the spring of 1940, the Commission instituted integration proceedings with respect to nine major utility holding company systems....." Securities and Exchange Commission, 10th Annual Report, p. 62.

[2] Holding Company Act Releases 6489, 7091, 7208.

Analysis

The economic effects of application of the law on this firm system must be negligible. As far as plant costs are concerned, it may have speeded up interconnection, but that is all. Since the number and size of electric subsidiaries was not affected, it could not have had any effect on firm economies. The only result was in the elimination of some of the "superstructure" of the system, and this was not a result of application of Section 11 (b) (1).

Columbia Gas and Electric Company

Although the Columbia system was one of the large utility holding companies, having a book value of more than 1/3 billion dollars in 1939, the bulk of the consolidated subsidiaries were engaged in the gas business. There were only five electric subsidiaries, all operating in the same general area, in southwestern Ohio and adjacent portions of Indiana and Kentucky (see map).

In the system's Section 11 (e) (voluntary) plan to meet the requirements of the Act, which was disapproved by the Commission,[1] it took the position that all its properties were one integrated system, and hence refused to present any evidence to meet the "ABC" provisions to show that the electric properties could be retained as an additional system or

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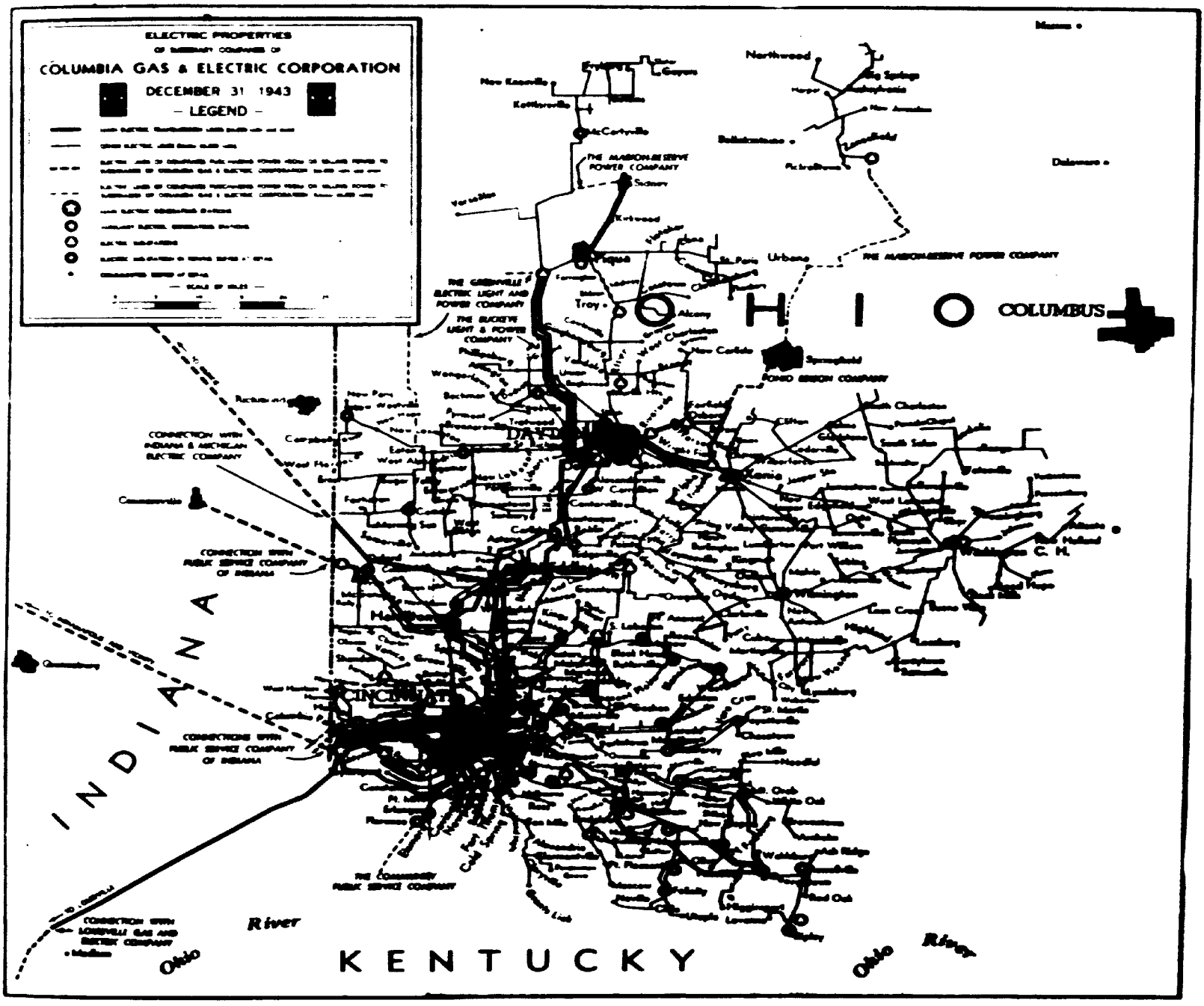
[1] Holding Company Act Release 2477, January 10, 1941.


ELECTRIC PROPERTIES
COLUMBIA GAS & ELECTRIC CORPORATION
DECEMBER 31 1943
– LEGEND –
O H I O
COLUMBUS
INDIANA
KENTUCKY
River
THE ASHBROOK-BESSEMER POWER COMPANY
THE GREENVILLE ELECTRIC LIGHT AND POWER COMPANY
THE BUCKEYE LIGHT & POWER COMPANY
OHIO EDISON COMPANY
CONNECTION WITH INDIANA & MICHIGAN ELECTRIC COMPANY
CONNECTION WITH PUBLIC SERVICE COMPANY OF INDIANA
CONNECTIONS WITH PUBLIC SERVICE COMPANY OF INDIANA
THE COMMUNITY PUBLIC SERVICE COMPANY
CONNECTION WITH LOUISVILLE GAS AND ELECTRIC COMPANY
Northwood
Urbana
Troy
Piqua
Sidney
Eaton
Richmond
Portsmouth
Ohio River

systems in addition to the integrated gas properties.[1]

In the Section 11 (b) (1) decision of the Commission in 1944, the greater part of the natural gas system was determined to be an integrated system within the meaning of the Act, but the electric properties (among others) were ordered disposed of.[2] No testimony as to loss of firm economies was made throughout the hearings. Thereafter, Columbia no longer claimed the electric properties were retainable, and was agreeable to their separation from the system. The electric properties themselves were the Dayton Power and Light Company and the Cincinnati Gas and Electric Company, together with three small companies which were "operated as a unit without regard to corporate entities" by Cincinnati.[3]

Dayton, the smaller of the two, served a contiguous territory in and around that city which had an estimated population of 410 thousand in 1943. In that year, the book value of its gross electric plant was 46 1/3 million dollars, and

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[1] The Commission has consistently held (with the single exception of the first case concerning this point, that of American Water Works and Electric Company, Holding Company Act Release 949 (1937)), that both gas and electric companies cannot be part of the same integrated public utility system. This interpretation was first made in this case.

[2] Holding Company Act Release 5455. "Tentative conclusions" in the case were rendered on May 2, 1944, in Holding Company Act Release 5024.

[3] Holding Company Act Release 6120.

gross electric operating revenue was about 14 million dollars. The company generated in that year 880 million kwh. of electricity, purchased 2 1/2 million kwh. from non-affiliates, and received 10 1/2 million kwh. from Cincinnati through an interchange agreement. Under that agreement it sent 8 million kwh. to Cincinnati, and sold some 64 million kwh. to non-affiliates.

The Cincinnati property served, in 1943, a contiguous area with an estimated population of 800 thousand. The book value of its electric utility plant at the end of that year was 91 1/2 million dollars, and gross electric operating revenues during the year amounted to about 25 million dollars. In the same year, the company generated 2 1/10 billion kwh. of energy. It purchased 13 1/2 million kwh. from non-affiliates and received some 45 million kwh. under interchange agreements with Indiana and Michigan Electric Company, Public Service Company of Indiana and Louisville Gas and Electric Company, as well as Dayton. Gross interchanges out amounted to more than 260 million kwh.,[1] with about 80 million kwh. going to Public Service Company of Indiana, and the bulk of the rest to Louisville. Dayton and Cincinnati were tied together with two 66 kv. transmission lines.

According to the testimony presented in the decision on the Section 11 (e) plan, the system's service company

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[1] Statistics, 1943, p. 641.

performed executive, administrative, financial, statistical and technical functions; specifically, it handled "financing operations, preparation of construction budgets, rate changes, etc." It was brought out in the Section 11 (b) (1) decision, however, that the two electric companies, unlike the other system companies, obtained their capital in large measure by the sale of securities to the general public. The gas properties were financed largely by Columbia and all of their securities were held by the holding company.

In 1945, the Commission approved (under Section 10 (c) (2)), the transfer of the three small electric companies from Columbia to Cincinnati.[1] Two of these properties served as distributors only in small adjacent areas in Indiana and Kentucky, and the third was solely a 132 kv. transmission line tying Cincinnati into the Louisville Electric Company. As noted above, these properties were operated as a unit by Cincinnati. They had common officers and executives and a centralized purchasing service.

Columbia never attempted to unite the two companies or to dispose of them as a unit. Dayton's stock was sold to the general public on June 10, 1946,[2] and Cincinnati's was disposed of in August, 1946, by offer to Columbia's stockholders and sale to the general public.[3]

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[1] Holding Company Act Release 6120.

[2] Holding Company Act Release 6656.

[3] Holding Company Act Release 6840.

In 1948, Dayton acquired six small electric properties located in Ohio[1] from United Public Utilities Corporation, a registered holding company which divested them pursuant to a section 11 (e) plan.[2] These companies served about 14,400 customers out of a total population of 27,000. Gross electric operating revenues for the companies in 1947 were 1.3 million dollars, of which 816 thousand dollars was contributed by one of them, the Greenville Electric Light and Power Company. These companies served a compact area in southwestern Ohio and were surrounded on three sides by Dayton, and there were three interconnections.[3] These six companies purchased about 97 per cent of their energy requirements from Dayton, generating the remainder in two small hydro-electric plants. Dayton outbid another utility, Central Ohio Light and Power Company,[4] for the properties, offering what the Commission thought was a very high price for them on the basis of their assets and past earnings record. Dayton justified its offer on the grounds that, even though it would lower rates of these companies to its own levels, it anticipated a decrease in the

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[1] Holding Company Act Release 7984.

[2] See below, p. 292.

[3] See map of United Public Utilities system, below, p. 290.

[4] Central Ohio's service area was also near those of the UPU subsidiaries.

cost of electricity which they were currently purchasing from it, and a reduction in operating expenses and general taxes due to "economies." Dayton merged these companies into itself September 30, 1948.

Analysis

It is not apparent that any plant economies were lost by separation of the two companies from the system and from each other. As can be seen from the data, interchange of energy between the two was minor compared to total energy used. Cincinnati interchanged much more with Louisville and Public Service of Indiana than with Dayton, and Dayton sold a good deal more to non-affiliates than it interchanged with Cincinnati. There is no reason why the interchange agreement could not remain in existence after separation, since interchange agreements with non-affiliates were much used by both companies. The economic integration of Cincinnati and the three small companies was not changed.

The acquisition of the former United Public Utilities' subsidiaries by Dayton undoubtedly gave rise to plant economies, since Dayton would not have offered such a high price for them unless it was sure that it would be worth while to do so.

Not much can be said on the basis of the evidence presented concerning loss of firm economies. Whether the company refused to offer evidence on loss of firm economies under clause (A) as a matter of principle, or because there was

little to show, is not, of course, known. The company's later willingness to agree to separation of the electric companies from the system proves neither point.

On the basis of the record, it can be said, however, that no financing losses could be expected by the electric properties. It is also far from clear how helpful a service company of a predominately gas system would be to the electric companies. From a technical standpoint, the two businesses are entirely different. It would not appear, on the basis of the jobs performed by the service company for the system as a whole, that any diseconomies might arise from separation except in that area which has previously been labeled administration and general expenses. The behavior of these expenses are shown in Table 15. Included in the table is the Greenville subsidiary of UPU, the only one of the six acquired by Dayton large enough to have data on it available.

The averages of these figures for the period as subsidiaries and as independents are as follows: Cincinnati, 4.1 per cent and 3.3 per cent, a decline of 20 per cent; Dayton, 3.7 per cent and 3.0 per cent, a decline of 19 per cent; the average for Greenville, while a subsidiary of UPU, was 4.1 per cent.

As far as the data show, acquisition of the UPU subsidiaries by Dayton resulted in gains in firm economies. Both Dayton and Cincinnati show percentage declines much greater

TABLE 15

DIVESTED SUBSIDIARIES OF COLUMBIA GAS AND ELECTRIC COMPANY
Administrative and General Expenses (Excluding the Pension Account) as a Percentage of Gross Electric Operating Revenue

Year	Dayton	Cincinnati	Greenville
1938	4.0	3.9	3.7
1939	4.0	4.7	4.3
1940	3.6	4.2	3.9
1941	3.7	3.4	3.4
1942	3.5	3.7	4.4
1943	3.8	4.1	4.5
1944	3.5	3.9	4.5
1945	3.6	4.7	4.7
1946	4.0[b]	4.6[b]	4.5
1947	3.0	3.8	4.0
1948	3.4[a]	2.8	3.5
1949	3.2	3.3	
1950	2.3	3.3	

[a] Six small companies, including Greenville, were merged into Dayton on September 30, 1948.

[b] Year divested.

than national average over the same periods.[1]

The Commonwealth and Southern Corporation

The application of Section 11 (b) (1) to this holding company system has been a long, drawn out affair. Proceedings were begun on March 6, 1940,[2] the major decision was reached

[1] See Appendix.

[2] Holding Company Act Release 1956.

by the Commission on August 2, 1947,[1] and compliance with that decision has only recently been completed.

As the map of the system shows, Commonwealth and Southern's operating properties were concentrated in the southeast, in South Carolina, Georgia, Florida, Mississippi and Alabama; and in the Great Lakes region of Illinois, Michigan, Indiana, Ohio and Pennsylvania. As of 1938, the aggregate population of the territories served was more than 9 million.[2] As of September 30, 1946, total combined book assets of the system (which contained exactly the same properties as in 1938) was about 1.1 billion dollars, almost equally divided between the northern and southern companies. For the 12 months ending on that date, the total gross revenues of the combined system (almost entirely electric) were 224 million dollars, about 121 million dollars of which was attributable to the northern companies, 123 million dollars to the southern group.[3]

The question of whether all of the properties were retainable together never arose under Section 11 (b) (1) since, in order to meet the simplification requirements of Section 11 (b) (2), Commonwealth and Southern submitted a

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[1] Holding Company Act Release 7615.

[2] Holding Company Act Release 1956.

[3] Holding Company Act Release 7615.

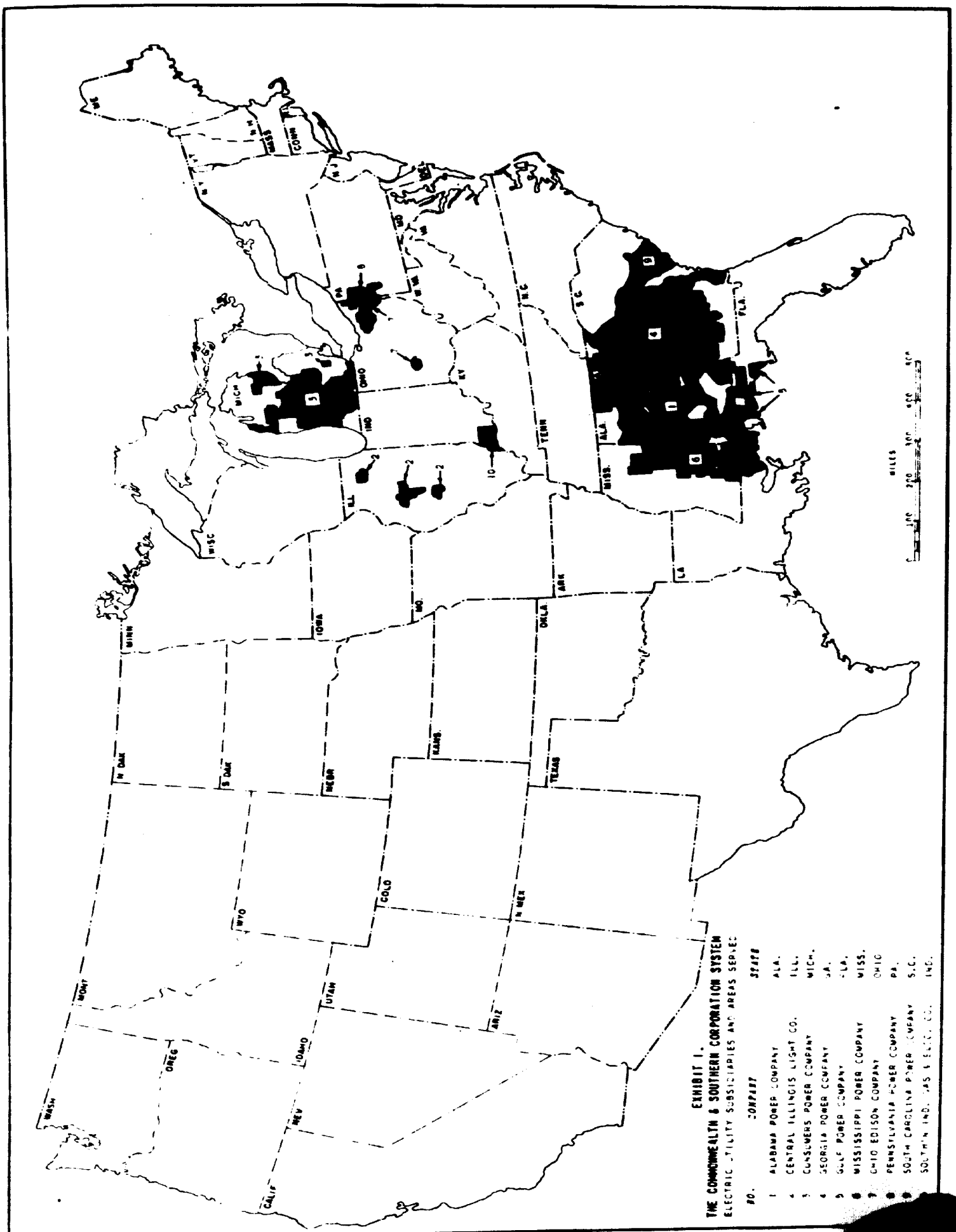
EXHIBIT 1.
THE COMMONWEALTH & SOUTHERN CORPORATION SYSTEM
ELECTRIC UTILITY SUBSIDIARIES AND AREAS SERVED
NO. COMPANY STATE
1 ALABAMA POWER COMPANY ALA.
4 CENTRAL ILLINOIS LIGHT CO. ILL.
5 CONSUMERS POWER COMPANY MICH.
6 GEORGIA POWER COMPANY GA.
7 GULF POWER COMPANY FLA.
8 MISSISSIPPI POWER COMPANY MISS.
9 OHIO EDISON COMPANY OHIO
10 PENNSYLVANIA POWER COMPANY PA.
11 SOUTH CAROLINA POWER COMPANY S.C.
12 SOUTHERN IND. GAS & ELEC. CO. IND.
MILES
WASH
OREG
CALIF
NEV
IDAHO
MONT
WYO
UTAH
COLO
ARIZ
N MEX
N DAK
S DAK
NEBR
KANS.
OKLA
TEXAS
MINN
IOWA
MO
ARK
LA
WISC
ILL
MICH
IND
OHIO
KY
TENN
MISS.
ALA
GA
FLA
S.C.
N.C.
W VA
PA
N.Y.
VA
MD
DEL
N.J.
CONN
MASS
R.I.
VT
N.H.
ME

voluntary (Section 11 (e)) plan which envisioned distribution of the stock of all the northern companies to its stockholders as a method of simplifying its capital structure.[1] Although the plan was subsequently revised a number of times, this feature was always retained. Hence, there is no information or discussion as to whether economies would or would not be lost by such separation.

The main Section 11 (b) (1) problem was what parts of the southern group might be retained together as an integrated system. As noted above, a decision on this point was reached in 1947. The Commission considered the Alabama, Georgia, Florida and Mississippi companies as a group, excluding South Carolina Power Company. As the map shows, the service area of this group is geographically contiguous, with only minor breaks in the entire operating area. It covers about 94 thousand square miles, and in 1946, served about 2/3 million customers. The companies were completely interconnected.[2] There had been common planning, development and operation, commencing in the mid-twenties, and since 1930 there had been a central load dispatching office in Birmingham which had coordinated the use of generators

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[1] Holding Company Act Release 5825. It was clear that these properties would not be retainable with the southern group because of the Commission's interpretation of clause (B).

[2] Mississippi, Georgia and Gulf were all connected directly with Alabama.

and power exchange throughout the system (on a contractual basis). There had been (and is now) considerable interchange of power in the system. In 1945, for example, Alabama (with large run-of-river hydro plants) supplied about 15 per cent of Georgia's energy requirements, 37 per cent of Gulf's and 62 per cent of Mississippi's, a total of about one billion kwh. In return, Alabama received about 3 per cent of its requirements (92.5 million kwh.) from the other companies, mostly from Georgia.

More than half of the generating capacity of the system is hydro, and is located in two states: Alabama, where, as noted above, it is mainly river flow type, and Georgia, which has mostly storage, that is, dammed water. The Commission felt that, on the basis of the record,

> .... the large size and different types of hydro-electric facilities in Alabama and Georgia require that there be close coordination of such facilities among themselves and with the fuel-electric generating plants to achieve maximum generation from the available water supply.

The coordination of these diverse units by a central dispatcher assures that no water flowage will be wasted--that is, any actual flow will be utilized for generation, and hence there will be less use of stored water or fuel for generation--and so less capacity is needed for the system than would be necessary for the companies separately. It was noted that there had been system planning of generating facilities in order to insure construction at the most economical operating sites irrespective of corporate limits, and also, of course,

to minimize needed reserves. The largest hydro plants were in Alabama because of water supply, and were designed to supply energy to the other companies.

On the basis of the record, the Commission determined that the system achieved economies both by pooling capacity and by using centralized dispatching on the basis of marginal costs, and that the break-up of these companies would result in the loss of substantial operating economies. It was felt that these economies overrode the criteria of localized management and effectiveness of regulation,[1] and thus this group of properties met the requirements of Section 2 (a) (29) (A) and 11 (b) (1). It should be noted that the Commission's opinion was that this system approached the maximum size consistent with those two sections.

South Carolina was determined to be neither a part of this system, nor a permissible additional system. Although it had, for some years, been developed and operated in conjunction with the other companies, the record convinced the Commission that "its power supply coordination is oriented toward [non-affiliates]." It was (and is) interconnected with Georgia and bought nearly 5 per cent of its power requirements from that company, but it purchased about 56 per cent of its energy from closer (non-affiliated) sources,

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[1] There was no state commission regulating electric companies in either Mississippi or Florida at this time.

mainly from South Carolina Public Service Authority's Santee-Cooper hydro project, which is only 30 miles from Charleston, compared with 250 miles to Georgia's main generating plant. Further, it was testified that the completion, in 1947, of the Company's new steam plant, near Charleston, should make it even less dependent on Georgia for energy. The Commission concluded:

> .... while we have been moved to permit the continuance of the proposed large combination of electric properties under the common control of Southern, in the main so as not to disturb their present and historical coordination and efficiency, there is no such justification for permitting the continued joinder of South Carolina Power.

Since this was so, it was felt that retention in the system would violate the localized management and effectiveness of regulation requirements of Section 2 (a) (29) (A). Likewise, South Carolina could not be retained as an additional system because of the similar considerations involved in applying clause (C). The Commission could find no loss of economies under clause (A) in the record, and Commonwealth and Southern made no claim of such. It appears that nowhere in the hearings did the holding company claim any loss of economies by South Carolina upon separation.

Commonwealth and Southern had offered a voluntary (Section 11 (e)) plan to set up a new holding company over the integrated southern system, which was to remain intact. In its plan, it had stated that if the four companies were found to be retainable together, it would dispose of its interests

in all other companies. The reason for the emergence of a new holding company was that it appeared that considerable new capital would be needed by these subsidiaries, of which it was desirable that a large portion should be equity capital.[1] The holding company stated that it was unable to furnish this because of the considerable arrears on its preferred stock and the Section 11 (b) (2) order to eliminate this class of stock. It was felt that a new holding company could obtain the necessary equity capital. The Commission was agreeable to this and the Southern Corporation was set up, which exchanged its stock with Commonwealth and Southern for the stocks of Alabama, Gulf, Mississippi and Georgia. South Carolina and all the northern properties were ordered divested.

Before turning to these other properties, it should be noted that the Southern Corporation filled one of the gaps in its operating territory by the acquisition of the Birmingham (Alabama) Electric Company from Electric Bond and Share's subsidiary which was under Commission orders to divest the property. The Commission approved the acquisition under Section 10 (c) (2) on August 24, 1950.[2] By the time of this case, the Southern system had a consolidated electric plant

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[1] It was estimated that more than $100,000,000 in new capacity would be needed in the next year.

[2] Holding Company Act Release 10055.

account of more than 512 million dollars (total consolidated assets were 622.5 million dollars) with annual electric revenues of 118.5 million dollars for the year ending May 31, 1950. Birmingham, although it served only 96 square miles, had a gross electric plant at original cost of 20 million dollars, and gross electric operating revenues for the same period were 10 million dollars. The Alabama subsidiary of Southern completely surrounded the service area of Birmingham, and it had purchased all of its power requirements from Alabama since 1914. In some cases, the two companies served customers on opposite sides of the same street.

During the hearings, it was testified that the estimated aggregate savings in operation would be $296,044 annually. Savings were anticipated in the following accounts: transmission and distribution operation and maintenance, customers accounting and collection, sales promotion, administrative and general, miscellaneous. No breakdown was given. It was also expected that common ownership would result in savings in capital expenditures for transmission and distribution facilities, which would aggregate $2,430,322 over a 10-year period, which, as the Commission said, "when and if achieved, will result in substantial annual savings." The plan was to eliminate Birmingham as a separate legal entity and to integrate the property with Alabama. This has not as yet been completed, so far as is known.

The sale of South Carolina Power Company to South

Carolina Electric and Gas Company was approved on March 26, 1948.[1] Electric and Gas was not at that time a holding company or a subsidiary or affiliate of a public utility or holding company, although prior to divestment it had been a subsidiary of Associated Gas and Electric Company.

The two companies were of about the same size: in 1947, South Carolina's gross operating revenue was 8.1 million dollars (about three-fourths of which was from electric operations), while Electric and Gas' was 8.4 million dollars (about four-fifths of which was from electric operations). The two service areas adjoined, as may be seen by comparing the map of Associated Gas and Electric's subsidiaries with that of Commonwealth and Southern's, and the properties were interconnected at four points, two of which were 144 kv. ties. Electric and Gas had 227,130 kw. of capacity, of which 2/3 was hydro and 1/3 steam, while South Carolina had 65,100 kw. of capacity, of which about 1/3 was hydro and 2/3 steam.[2]

Since this was not a Section 10 (c) (2) case, the Commission having no jurisdiction over Electric and Gas, there was no discussion of economies due to integration. The main feature of the case was the opposition of the negotiated sale

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[1] Holding Company Act Release 8080.

[2] It will be remembered that South Carolina purchased a large part of its energy requirements.

by the City of Charleston and the South Carolina Public Service Authority, on the grounds that the competitive bidding requirements of the Act (Section 12 (d)) were not being met. The Authority, a public power agency of the state of South Carolina, had offered Commonwealth and Southern $11,600,000 for the common stock, while Electric and Gas' accepted offer was for $10,200,000. The Board of Directors of Commonwealth accepted the latter offer on the grounds that it was "far more certain of consummation and did not constitute a competitive publicly operated threat to the neighboring southern companies remaining subsidiaries of Commonwealth." The first part of the quote refers to the fact that there was a question as to the legality of the Authority acquiring the property.[1]

The objectors also claimed that the financial structure of Electric and Gas was inadequate to justify the acquisition and that the sale would endanger the ability of the combined companies to finance necessary improvements, as well as eliminating the probability of rate reductions in the service area for "several years."

The Commission pointed out that it had no jurisdiction over the purchase of South Carolina's stock, but that the same arguments had been made to the South Carolina Public Service

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[1] Estimates as to how long it would take for the state supreme court to decide the issue ranged from 30 days to one year.

Commission, which had approved the transaction.[1] The Commission approved the sale.

More information concerning the effect of the acquisition is available in the Federal Power Commission's order dated April 29, 1948.[2] The record here indicates that the Authority argued that the hydro generating capacity of the two companies was insufficient to supply the area's load, and hence, as the load grew, new steam generating capacity would have to be built, resulting in higher costs. On the other hand, the integration of the Authority's hydro capacity with South Carolina would mean lower costs.

The city argued that the sale would hinder the expansion of power facilities in its area, and in addition, the earnings of South Carolina entitled its customers to a rate reduction, but that the applicant's plan was to postpone any reduction until 1951.

The FPC pointed out that its powers in this case were limited to determining whether the acquisition was "consistent with the public interest," and that the courts had held this to mean simply "compatability."[3] Thus, granting that the

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[1] Order adopted November 6, 1947, and upheld by the Court of Common Pleas, Richland County, S. C. Cited in Opinions and Decisions of the Federal Power Commission, Vol. 7 at p. 606.

[2] Ibid.

[3] Pacific Power and Light Co. et al. v. Federal Power Commission, 111 F. 2d. 1014, cited in the above decision.

Authority was correct in that the facilities of the combination were not adequate to meet the needs of the area without large capital expenditures, and that a more economic method of meeting the need would be the integration of South Carolina with it, it was pointed out that this was not enough to support a finding that the proposed acquisition was not in the public interest. The FPC concluded that completion of construction initiated by South Carolina would result in loop operation between the eastern and western centers of the combined system so as to allow central dispatching, and hence bringing into use lowest (marginal) cost unused capacity. This, it was felt, would also make possible increased accumulation of stored water in hydro projects to carry peak loads, thus, evidently, making less capacity necessary. The conclusion regarding savings in reserve capacity is not clear (due probably to a misprint):

> Integration of the properties will diminish the reserve capacity required to maintain service, as the indicated reserve required for the integrated properties would be practically the same as that for the separate properties independently operated. [!]

The FPC decided it must approve the acquisition because "it is reasonable to conclude that some benefits may be derived from the consummation of the proposed acquisition."

It should be pointed out that Commonwealth and Southern's decision had what would appear to be uneconomic repercussions. As was pointed out by the city of Charleston in the Federal Power Commission case, the merger would

"jeopardize" the continued availability of power "at favorable rates pursuant to a short term contract" from the Authority, to the detriment of consumers. Subsequent to the agreement between Commonwealth and Southern and Electric and Gas, the Authority gave notice (24 months were required) of its intention to terminate its power contract with South Carolina.[1] As far as can be determined, the integrated system does not now receive any power from the Authority. South Carolina was actually merged into Electric and Gas on March 31, 1950.[2]

It will be remembered that Commonwealth and Southern intended to divest all of the northern properties. Prior to divestiture, the holding company desired to donate the common stock of one of the subsidiaries, Pennsylvania Power Company, to another, the Ohio Edison Company. The Commission approved the transfer on September 14, 1944.[3] As may be seen on the map, the operating territory of Pennsylvania Power was contiguous with the main part of the Ohio Edison area. Testimony indicated that the properties were interconnected at 16 points, and had been operated as a single coordinated system "for many years." In addition, the construction programs of

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[1] Holding Company Act Release 8080.

[2] Moody's Manual, 1951.

[3] Holding Company Act Release 5289.

the two companies had been based on the anticipation of continued coordination of operation. It was stated later, in the Section 11 (b) (2) decision,[1] that the purpose of the donation "was to insure the preservation of the economies now enjoyed by Ohio Edison and Pennsylvania Power from the operation of their interconnected electric properties under common control." It was pointed out by the Commission that it had not passed on the retainability of the Springfield, Ohio, division of Ohio Edison, which was located some 150 miles from the main area and with which it was not connected, although to date the Commission has taken no action as to its retainability.[2]

Commonwealth and Southern sold the entire common stock of Southern Indiana Gas and Electric Company through underwriters to the general public in January, 1949.[3] The stocks of Central Illinois Light Company, Consumers Power Company and Ohio Edison were distributed to the preferred and common stockholders of Commonwealth as a liquidating dividend on October 1, 1949.[4]

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[1] Holding Company Act Release 5825.

[2] As a registered holding company, Ohio Edison is still under the jurisdiction of the Commission.

[3] Holding Company Act Release 8489.

[4] Holding Company Act Releases 8633 and 8698. Commonwealth is thus no longer active and is engaged in winding up its corporate existence.

Ohio Edison, as an independent holding company, received the approval of the Commission[1] to acquire the common stock of Ohio Public Service Company from Cities Service, which was under order to dispose of this property. The approval was based on the anticipated savings to be obtained by coordinating the operation of the two properties. As may be seen by comparing the maps of Cities' and Commonwealth's subsidiaries, the service areas were contiguous, those of Public Service lying to the north, west and south of Ohio Edison's main area. Portions of the two areas were interspersed with each other, and there was much paralleling and crossing of main transmission lines. The companies were interconnected at three points, and there was an interchange agreement between them.

The President of Ohio Edison testified that the generating capacity necessary under individual operation could be reduced considerably by common ownership due to two things: the fact that there was considerable diversity between the two companies in the time of maximum demands, and the combining of reserve capacity and scheduling of maintenance work. He estimated that by the end of 1953, the combined properties would require 120,000 kw. less capacity than if they were independently operated, and thus net plant investment would be about 18 million dollars lower, or an annual

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[1] Holding Company Act Release 9539.

saving of $1,155,000. Further savings estimated as high as $350,000 annually were expected from central dispatching to obtain lowest possible generating costs, pooling of transmission line facilities and "the free-flow of power over the unified system, thereby increasing the effective carrying capacity of the present lines."

The combined properties represented about 290 million dollars in gross utility plant and 80 million dollars in gross annual electric operating revenues.[1] Public Service was merged with Ohio Edison in 1950.[2] The Company presently has interchange agreements with Cleveland Electric Illuminating Company, Dayton Power and Light Company, Ohio Power Company (a subsidiary of American Gas and Electric Company), and Toledo Edison Company.

One more case concerning this system is of interest in this study. In 1949, the Commission promulgated a decision concerning the future of the service company of Commonwealth and Southern.[3] A new system service company was set up to serve the subsidiaries of the Southern Corporation, while the old system service company became an independent, with the

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[1] As of August 3, 1949, the utility plant of Ohio Edison was $181,000,000, and revenues for 12 months ending that date were about $46,000,000. The figures for Public Service were $107,000,000 and $31,000,000 respectively.

[2] Holding Company Act Release 9771.

[3] Holding Company Act Release 9362.

expectation of serving the former northern subsidiaries as well as other companies. Without going into the complexities of the case, which arose under Section 13 of the Act, it seems useful to note the description of the services to be rendered by the two companies. The now independent service company proposed to offer the following categories of services to its former affiliates (and others):

1. Engineering and construction and advisory engineering
2. Consultation on operating and miscellaneous problems and construction programs
3. Financing new security issues
4. Financial, accounting and statistical
5. Taxes
6. Rate consultation, advice and research
7. Auditing
8. Advice and assistance in connection with pension matters
9. Insurance
10. Purchasing, inspection and expediting
11. Advertising and information
12. Appliance merchandising and appliance service
13. Meter engineering and development
14. Display
15. Stock transfer

No contracts were to be entered into between the service company and its clients (at least, the former affiliates) for managerial or supervisory types of service. The work was to be done, in general, on specific work assignments from the clients. The purpose of this was to assure "reasonable" self-sufficiency for the divested companies in order to assure full compliance with Section 11 (b) (1).

The new service company of Southern proposed rendering services in the following categories:

1. Power pool operations
2. General advisory

3. General engineering
4. Design engineering
5. Purchasing
6. Accounting
7. Taxes
8. Insurance
9. Corporate
10. Rates

Several categories--meters, displays, advertising and financial advice and assistance--were not included. It was felt that the subsidiaries, with the help of the staff of Southern, could perform these. In addition, it was stated that the possibility existed that the services of outside companies might be needed from time to time. Just why they might be needed is not clear from the record.

Analysis

There is only one possibility of loss of plant economies in the application of Section 11 (b) (1) to Commonwealth, that of South Carolina's separation from the present subsidiaries of the Southern Corporation. In view of the fact that, at the time of the decision, South Carolina received only 5 per cent of its requirements from the other companies, that it was anticipated by the company that less than this amount would be needed after 1947, and that interchange still exists, it would seem doubtful that there actually was any loss.

The problem of whether South Carolina should have been integrated with the Authority rather than Electric and Gas, in order to attain maximum plant economies, is not directly relevant here, since this decision was entirely up to the

management of Commonwealth. It should be noted, however, that Electric and Gas had been selling rather more than half of its total generation to two other utility companies before the acquisition, and continued to do so afterwards,[1] while at the same time supplying power to South Carolina,[2] which probably indicates less loss of possible economies than the testimony seemed to indicate. In any event, the central dispatching in the new system seems to indicate savings in operating costs and capacity requirements compared to the situation obtaining while Commonwealth still controlled South Carolina.[3]

The acquisition of Birmingham by the Southern system seems highly desirable from an economic standpoint.

The acquisition of Pennsylvania Power by Ohio Edison merely retained an historic operating relationship and had no effect on operational costs. The acquisition of Ohio Public Service by Ohio Edison, however, seems rather peculiar. Public Service, together with Toledo Edison, had been found to be an integrated system within the meaning of Section 2

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[1] The companies were Duke Power and Carolina Electric Company. Moody's Manual, 1947-1951.

[2] After 1947, there was considerable interchange between the two companies, with, of course, a net inflow to South Carolina. Compare "physical quantities" and "electric operating revenues" for the two companies, in Federal Power Commission, Statistics, 1947 and following years.

[3] Account should be taken of the fact that hydro power from the Authority was replaced to a great extent by hydro power from Electric and Gas.

(a) (29) (A) in the Cities Service Section 11 (b) (1) decision.[1] If the two companies actually were operationally integrated, it would seem uneconomic to separate them. However, it should be remembered that the record indicated only that they were interconnected and had (some) contiguous operating areas. There was no indication that they actually were (or that it was desirable that they should be) operated as a unit. The record did not show that there was central dispatching or joint planning of capacity. As a matter of fact, Public Service had an interchange agreement with Toledo Edison, just as with Ohio Edison. The maps of the two systems show that the service areas of Public Service were also contiguous with Ohio Edison's main area to the north, west, and south, and that these companies were interconnected. The reasonable inference that may be drawn from the fact that Ohio Edison, rather than Toledo Edison, purchased Public Service, would seem to be that the former company saw more possibility of operational savings. As a matter of fact, there is no record that Toledo Edison either desired or considered buying Public Service. Since the interchange agreement with Toledo Edison is still in effect, there is no reason for loss of economies upon separating Toledo Edison and Public Service from common holding company control. In view of the data presented, considerable economies should accrue because

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[1] See above, p. 69.

of the merger.

The question of whether any of the former subsidiaries lost firm economies is one which cannot be answered satisfactorily. There are two reasons for this. First, there is no testimony in the record to show whether any losses were anticipated by the system. Second, and more important, all of the companies (except South Carolina Power, which was sold in 1948), were divested by Commonwealth and Southern in late 1949, and hence, data for only one year of independence are available. The following table contains the available information on administrative and general expenses for all of the former subsidiaries, with the exception of Ohio Edison.[1]

The averages for the companies as subsidiaries, and the average for the one year after divestment, are as follows: Alabama Power, 4.9 per cent and 4.8 per cent, a decline of 2 per cent; Gulf Power, 6.4 per cent and 6.1 per cent, a decline of 5 per cent; Georgia Power, 4.4 per cent and 4.0 per cent, a decline of 9 per cent; Mississippi Power, 6.6 per cent and 5.4 per cent, a decline of 18 per cent; South Carolina Power, 5.1 per cent and 4.5 per cent (1949), a decline of 12 per cent; Pennsylvania Power, 4.4 per cent and 3.5 per cent, a decline of 20 per cent; Consumers Power, 3.9 per cent and 4.1 per cent, an increase of 5 per cent; Central Illinois Light, 2.9

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[1] Ohio Edison is excluded since, in its first full year of independence, 1950, it acquired the properties of Ohio Public Service, a company nearly as large as itself.

TABLE 16

DIVESTED SUBSIDIARIES OF THE COMMONWEALTH AND SOUTHERN CORPORATION
Administrative and General Expense (Excluding the Pension Account) as a Percentage of Gross Electric Operating Revenue

Year	Consumers Power	Central Illinois Light	Southern Indiana Gas & Electric	Alabama Power	Gulf Power	Georgia Power	Mississippi Power	South Carolina Power	Pennsylvania Power
1938	4.8	3.5	3.6	6.0	7.1	5.6	8.9	7.6	4.8
1939	4.6	3.4	4.7	5.8	8.0	5.2	8.5	7.3	4.6
1940	4.1	3.3	3.9	5.7	7.6	4.9	8.5	7.3	4.8
1941	3.5	2.6	3.5	4.6	8.2	4.3	7.9	6.0	4.5
1942	3.9	3.0	3.2	4.5	6.7	3.7	6.4	5.4	4.0
1943	3.2	2.8	2.7	4.3	5.8	3.5	5.3	4.8	3.5
1944	3.8	2.6	2.3	4.4	5.0	4.0	5.3	4.6	3.6
1945	3.6	2.5	2.6	4.3	5.1	3.8	4.9	4.8	4.3
1946	3.9	2.5	2.6	4.6	5.4	4.5	5.4	5.3	5.0
1947	3.8	2.9	2.4	4.9	5.1	4.4	6.3	5.2	3.9
1948	4.0	2.6	2.8	4.4	6.2	4.3	5.2	4.5	4.5
1949	4.6	3.2	3.4	4.7	6.6	4.2	6.0	4.5	4.3
1950	4.1	3.3	3.3	4.8	6.1	4.0	5.4	a	3.5

[a] South Carolina Power was merged into its parent, South Carolina Electric and Gas, on March 31, 1950.

per cent and 3.3 per cent, an increase of 12 per cent; Southern Indiana Gas and Electric, 3.1 per cent and 3.3 per cent, an increase of 6 per cent. For the four companies which are presently subsidiaries of the Southern Corporation, the decline averages 7 per cent. Comparing these figures with the average decline for all companies in the United States of 8 per cent for the same period,[1] it appears that Pennsylvania Power and South Carolina Power have shown a relative decline in firm costs, that the three independent northern companies have shown a relative increase in those costs, and that the subsidiaries of Southern have shown no relative change. Since both companies which showed declines were subsidiaries of other electric companies during their first full year of separation from Commonwealth and Southern, it would appear that those companies which actually became independent upon separation suffered losses of firm economies.

Community Power and Light Company

In 1941, Community Power and Light Company, a small system, owned electric properties in six states:[2] Arkansas, Missouri, Texas, New Mexico, Kansas and South Dakota.[3] The

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[1] See Appendix.

[2] In 1941, the system's electric properties in Nebraska were sold to the Nebraska Power Authority.

[3] Holding Company Act Release 3041.

combined balance sheets of the subsidiaries at the end of that year showed total assets of $28,000,000, and electric service areas contained a total population of 274,000.[1]

Community agreed that its system did not meet the requirements of Section 11 (b) (1). It therefore proposed a Section 11 (e) (voluntary) plan to dispose of all its subsidiaries except those centered in the Panhandle section of Texas.[2] In a complex series of transactions, done mostly to meet Section 11 (b) (2) requirements, Community and its subsidiary holding and operating company, General Public Utilities, were merged into Southwestern Public Service Company (previously a subsidiary of General Public Utilities). Texas-New Mexico Utilities Company, another subsidiary, was liquidated, and its properties merged with Southwestern.

Eastern Kansas Utilities was sold to the United Light and Railways system,[3] and Southwestern acquired from this system Panhandle Power and Light Company and Cimarron Utilities and, later, the Morton county properties of United Light and Railways.[4]

These three United Light and Railways' properties

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[1] Moody's Manual, 1941.

[2] Holding Company Act Releases 3041 and 3676.

[3] See below, p. 274.

[4] Holding Company Act Releases 3667 and 4937.

were located in the extreme northern part of the Texas Panhandle, Oklahoma Panhandle and Southwestern Kansas. They were contiguous to each other (see map of United Light and Power system below, p. 272) and were interconnected. The service of the Panhandle companies and Southwestern were adjacent and Panhandle was interconnected with Southwestern. The Commission felt that the purchase had the tendency required by Section 10 (c) (2), since integration of the properties appeared "desirable from the standpoint of investors, consumers and the general public."

By 1944, all of the outlying properties had been sold. The stocks of the Black Hills Power and Light Company and Missouri Utilities Company were sold publicly in 1941.[1] The Holbrook (Arizona) Light and Power Company was sold to the municipality.[2] Arkansas Utilities Company and Arizona Electric Power Company were sold to individuals.[3] The electric properties of Gulf Public Service Company's northwest Texas properties were transferred to Southwestern. Gulf Public Service was then sold to an individual,[4] and with this transaction, Southwestern became purely an operating company

[1] Holding Company Act Releases 3096 and 3041.

[2] Holding Company Act Release 3676.

[3] Holding Company Act Releases 4526 and 4129. The latter company was sold to the same individual who later bought Arizona Power Corporation from United Gas Improvement Company.

[4] Holding Company Act Release 5188.

and was no longer under the jurisdiction of the Securities and Exchange Commission.

The company has since acquired some isolated electric properties from West Texas Utilities (a subsidiary of Central and Southwest Corporation, formerly a subsidiary of the Middle West Corporation) with which it was interconnected. It had been supplying them with 98 per cent of their energy requirements. Southwestern has also acquired a small independent New Mexico property at Santa Rosa.[1] The interconnected system is now about 300 miles long and 120 miles wide at its greatest extent.

Analysis

No plant economies have been lost by any of the former subsidiaries, since none that were interconnected have been separated. Although no data are available, it would seem that the formation of a large integrated operating unit in the Panhandle region, through exchange of properties with United Light and Railways and other acquisitions, should give rise to operating economies. The same results should also accrue to those former subsidiaries obtained by other operating companies or systems.

The size of the system has increased instead of decreased. The size of the properties acquired were slightly

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[1] Moody's Manual, 1951.

larger than those sold, so by 1945, total assets of Southwestern were $45,000,000. Tremendous increases in area demand has caused Southwestern to grow internally to a total asset figure of $114,000,000 in 1951.[1] The population served now totals 618,000, and gross operating revenues in 1951 were almost as large as total system assets in 1941.

Thus, it would not appear that losses to firm economies should be anticipated for the remaining properties in the system.[2]

The only question remaining to be considered, therefore, is whether any of the former subsidiaries that are now independent have lost firm economies in the process. Data are available for three of these companies, and Table 17 sets forth information concerning them.

Kansas, which became a subsidiary of United Light and Railways, shows averages of 7.7 per cent and 6.4 per cent, a

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[1] Moody's Manual, 1945-1951.

[2] It is not possible to evaluate this conclusion in terms of administrative and general expense data, since it is not possible to obtain figures for the same properties before formation of the Southwestern system. This is because certain of the Panhandle properties were operated by General Public Utilities, a subsidiary holding and operating company, which also operated the South Dakota properties, the Black Hills company not being formed until Southwestern was set up. In addition, the Texas properties of Gulf were merged into Southwestern; data on Texas-New Mexico are not available; and data on the Morton county properties of Kansas City Power and Light and Cimarron Utilities are not separately available. Hence, no figures can be arrived at with which to compare those obtainable after the formation of Southwestern.

TABLE 17

DIVESTED SUBSIDIARIES OF COMMUNITY POWER AND LIGHT COMPANY
Administrative and General Expenses (Excluding the Pension Account) as a Percentage of Gross Electric Operating Revenue

Year	Kansas Utilities (now Eastern Kansas Utilities)	Gulf Public Service	Missouri Utilities
1938	9.0	9.9[a]	8.4
1939	7.5	9.0[a]	7.8
1940	7.5	8.8	7.5
1941	6.9	8.6	7.3[b]
1942	b	8.8	6.9
1943	6.1	8.0	6.9
1944	6.1	8.1[b]	6.3
1945	6.3	9.7	6.9
1946	6.6	8.2	6.1
1947	6.8	7.7	7.0
1948	6.1	8.4	6.2
1949	6.3	7.3	5.8
1950	6.7	7.0	6.0

[a] Estimated.

[b] Year divested.

decline of 17 per cent; Gulf, as a subsidiary, averaged 8.9 per cent, and as an independent, 8.1 per cent, a decline of 9 per cent; Missouri, as a subsidiary, averaged 7.9 per cent, as an independent, the average is 6.5 per cent, a decline of 18 per cent. Comparing these declines with the national averages for the same periods,[1] no loss of firm economies due

[1] See Appendix.

to separation shows in the data.

The Ogden Corporation

Ogden came into existence on January 1, 1940, as the successor in bankruptcy of Utilities Power and Light Corporation, which was itself the subsidiary of Public Utilities Securities Corporation, a subsidiary of Webster Securities Company.[1] Under terms of the financial reorganization, the stock of Indianapolis Power and Light Company and Newport Electric Company were sold publicly, and Interstate Power Company of Nebraska was sold to Consumers Public Power District of that state.[2]

On December 31, 1942, Ogden controlled subsidiaries with total book assets of about $170,000,000, and yearly operating revenues of $22,000,000.[3] Among the subsidiaries were electric properties serving 8 states (see map).

Under terms of the financial reorganization of the system, Ogden was to become eventually an investment company. In the Section 11 (e) plan decided in this case, it proposed to divest all its utility operating companies and sub-holding companies. Ogden conceded that Derby Gas and Electric Company (and its subsidiary, the Wallingford Gas Light Company) was

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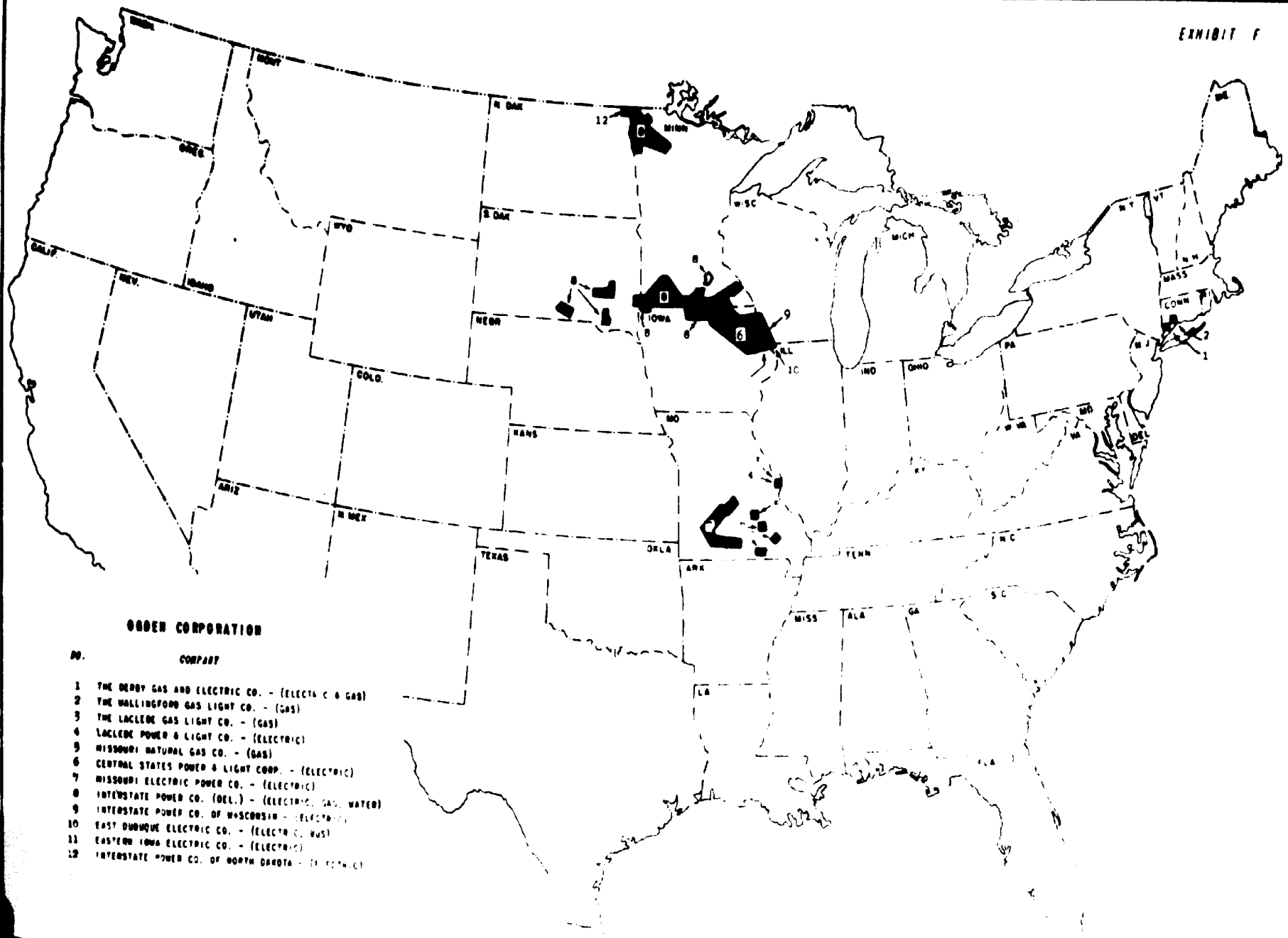
[1] Holding Company Act Releases 1665 and 4307.

[2] Holding Company Act Releases 1545 and 2001.

[3] Holding Company Act Release 4307.

EXHIBIT F



OGDEN CORPORATION

NO.	COMPANY
1	THE DERBY GAS AND ELECTRIC CO. - (ELECTRIC & GAS)
2	THE WALLINGFORD GAS LIGHT CO. - (GAS)
3	THE LACLEDE GAS LIGHT CO. - (GAS)
4	LACLEDE POWER & LIGHT CO. - (ELECTRIC)
5	MISSOURI NATURAL GAS CO. - (GAS)
6	CENTRAL STATES POWER & LIGHT CORP. - (ELECTRIC)
7	MISSOURI ELECTRIC POWER CO. - (ELECTRIC)
8	INTERSTATE POWER CO. (DEL.) - (ELECTRIC, GAS, WATER)
9	INTERSTATE POWER CO. OF WISCONSIN - (ELECTRIC)
10	EAST DUBUQUE ELECTRIC CO. - (ELECTRIC, GAS)
11	EASTERN IOWA ELECTRIC CO. - (ELECTRIC)
12	INTERSTATE POWER CO. OF NORTH DAKOTA - (ELECTRIC)

not retainable under clause (B) with any of the other properties. It further conceded that, with one possible exception, the rest of the properties bore no substantial economic relationship with each other, thus ruling out retention together under clause (A). The possible exception was the large (geographically) group of properties, subsidiaries of two subholding companies, Interstate Power Company and Central States Utilities Corporation, located in Minnesota and Iowa, with extensions into Wisconsin and Illinois.

A director of Ogden testified during the course of the hearings that the continuation of Ogden as a holding company was "uneconomical and unjustified," and that economies that could be achieved by its continued existence were "relatively non-existant by virtue of the scatteration of [its] holdings." The Commission noted that the Iowa-Minnesota group of properties might possibly be an integrated system or systems, but went on to say,

> The record indicates Ogden has no continuing function to perform in any such possible integration of facilities since Interstate Power Company, a registered holding company, can be used as a coordination vehicle and it has no need for a holding company above it.

Thus, the Section 11 (e) plan was approved.

In 1944, the Commission reached a decision on this adjoining group of properties in a case brought on by Ogden's wish to have Central States sell its subsidiary in this region, Central States Power and Light Corporation, to Interstate,

which owned the other properties.[1] Interstate's properties surrounded it on three sides, and it purchased 63 per cent of its power at wholesale from Interstate. The two systems were interconnected at four points, and the Commission said, "the record indicates that the combined facilities may be economically operated as a coordinated unit." The sale was approved under Section 10 (c) (2) and the group of properties was held to be an integrated system.

In this same decision, the sale of the remaining northern Minnesota-North Dakota properties, the Bemidji-Crookston division of Interstate, to the Otter Tail Power Company, an independent, was approved.[2] Although these properties were practically self-contained, buying only 5 per cent of their energy requirements, the service area was contiguous with Otter Tail on the east, and the companies were interconnected at one point. The Commission said that "further interconnections are contemplated by Otter Tail." The Federal Power Commission and the North Dakota Public Service Commission had approved the acquisition.[3] The Securities and Exchange Commissionhad no jurisdiction over the acquisition, but did approve the sale.

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[1] Holding Company Act Release 5351.

[2] Previously, sale of Interstate of North Dakota to this same company had been approved without hearings or comment in Holding Company Act Release 4440.

[3] The FPC had jurisdiction because of power crossing the state line.

The remaining electric properties were disposed of at about this same time. Laclede, as already noted, was sold to Union Electric Company of Missouri, then a subsidiary of North American; Missouri Electric Power Company sold its assets to Sho-Me Power Cooperative, Inc.; and the South Dakota assets were sold piecemeal to cities and cooperatives. Hence, the integrated system of Interstate, which at the end of 1945 showed consolidated book assets of $43,000,000,[1] was the only remaining utility subsidiary of Ogden. In 1948, the Commission ruled Ogden no longer was the parent of Interstate, because of the divestment of the bulk of Interstate's stock.[2] Ogden became an investment company. It is now in the process of dissolution.

Analysis

It is certain that no plant economies were lost through application of Section 11 (b) (1) of the Act to Ogden. It is equally certain that some gains in plant economies were achieved. As noted previously, the acquisition of Laclede by Union Electric gave this result. It is quite possible that the acquisition of the North Dakota-Minnesota properties by Otter Tail and the Missouri properties by Sho-Me gave rise to similar gains, but there is not enough evidence to demonstrate

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[1] Holding Company Act Release 6564.

[2] Holding Company Act Releases 7955 and 9139.

this. Apparently, the unification of the Minnesota-Iowa properties under Interstate did not change previously existing operating relationships.

On the basis of the testimony, no losses of firm economies should be anticipated. The following table gives the information for these companies for which data are available.

TABLE 18

DIVESTED SUBSIDIARIES OF THE OGDEN CORPORATION
Administrative and General Expenses (Excluding the Pension Account) as a Percentage of Gross Electric Operating Revenue

Year	Derby Gas and Electric Co.	Interstate Power Co. (Including Central States Power and Light, Merged Nov. 15, 1944	Interstate Power Co. of Wisconsin (Subsidiary of Interstate)
1938	6.6	6.8	6.3
1939	5.6	7.7	6.7
1940	5.3	7.9	6.4
1941	5.4	8.6	7.2
1942	4.5	7.3	8.0
1943	4.9	7.5	8.1
1944	5.9	7.5[a]	7.7
1945	5.5	5.4	4.1
1946	4.8	5.6	4.9
1947	4.6	6.1	4.8
1948	4.4	5.7	4.2
1949	5.0	5.7	4.2
1950	4.4	5.9	3.8

[a] Includes operation of the Crookston-Bemidji Minnesota properties until November 15, 1944.

Derby Gas and Electric, which was divested in 1944, shows an average of 5.4 per cent as a subsidiary and 4.8 per cent as an independent, a decline of 11 per cent. Interstate and its subsidiary formally became independent of Ogden in 1948, but as a matter of fact, Ogden had no other subsidiaries after 1944. Whichever date is chosen, it is clear that this portion of firm costs are considerably lower with less companies in the holding company system than with more. The averages for Interstate for the years 1938-1947 are 7.0 per cent; for 1949-1950 they are 5.8 per cent, a decline of 17 per cent. For its subsidiary, the same averages are 6.4 per cent and 4.0 per cent, a decline of 38 per cent. Averages for the years 1938-1944 and 1945-1950 show even greater reductions. Comparing these declines with the national averages for the same periods,[1] it does not appear that there were losses in firm economies in the break-up of Ogden.

Republic Service Corporation

This holding company was the smallest of those considered herein. In 1942, total book assets of its subsidiaries were less than $9,000,000.[2] There were 15 operating subsidiaries, of which 11 were electric companies. Four of these were located in Virginia, and the other 7 in Pennsylvania.

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[1] See Appendix.

[2] Holding Company Act Release 4128.

Three of the Virginia properties, known as the "Page" group, were interconnected and operated as a unit, serving the north end of the Shenandoah Valley. This group generated about 85 per cent of its own power. The Holston River Power Company was located about 250 miles from the "Page" group, in the southwestern corner of Virginia. The Pennsylvania properties, composed of five operating units, were scattered throughout the state and were not economically capable of being interconnected. Two of these groups were simply distributors; the rest generated the bulk of their own energy. The combined assets of the Virginia companies totaled about $3,500,000, and their gross operating revenues during 1942 had totaled about $500,000, while the combined assets of the Pennsylvania properties amounted to slightly more than $3,000,000, with revenues for 1942 totaling about $1,000,000.

The first decision in this case was on a voluntary (Section 11 (e)) plan of Republic's, which proposed consolidating the Virginia properties into a new company and divesting it to Republic's stockholders, with the Pennsylvania properties retained as an integrated system. The proposal was made since clause (B) ruled out the retention of both sets of companies in the same system. The Commission decided that under the circumstances, "the choice does not appear inappropriate to us." However, it raised the question of whether the Pennsylvania companies were retainable together as an integrated system or systems.

The decision on this question was made in 1946.[1] Therein the Commission determined that the requirements of clauses (B) and (C) were met by the retention of these properties, since it was obvious that their combination was not so large "as to impair the advantages of localized management, efficient operation, or the effectiveness of regulation," and they were all located in the same state. Concerning clause (A), the Commission said,

> The record indicates that none of the subsidiaries could be operated as individual systems without the loss of substantial economies, and therefore, we find that the requirements of clause (A) of Section 11 (b) (1) is satisfied. Accordingly, we shall take no action with respect to these companies under Section 11 (b) (1) of the Act.16/
>
> 16/ Our conclusion that the properties are retainable under Section 11 does not constitute nor should it be construed as an indication that we believe they should necessarily be retained in one holding company system. It was testified that certain of the properties should as a matter of business judgment be disposed of, if sales could be effected at a reasonable price. The stockholder plan provides that such sales are contemplated.....

Meanwhile, Potomac Edison Company, a subsidiary of West Penn Electric Company (formerly American Water Works and Electric Company) had proposed to buy the Virginia properties.[2] The Commission approved the sale of the "Page" group to Potomac Edison some months later.[3] The two were already

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[1] Holding Company Act Release 6820.

[2] Holding Company Act Release 5170.

[3] Holding Company Act Release 5731.

interconnected and there was considerable power interchange. Generating capacity of the "Page" group was composed entirely of four small run-of-river hydro plants. Thus, its output was subject to seasonal fluctuations which necessitated steam firm power in some months. It was anticipated that economies could be achieved by the operation of it as an integral part of Potomac. This group was merged into a subsidiary of Potomac Edison in 1946.[1]

In the same decision, American Gas and Electric Company's subsidiary, Appalachian Power, was given permission to acquire Holston River, the other Virginia subsidiary of Republic. Appalachian's service area almost entirely surrounded that of Holston River and Appalachian's transmission and distribution lines interlaced it in every direction. Holston River was then purchasing about one-half of its energy requirements from a Cities Service subsidiary, East Tennessee Light and Power Company, which in turn purchased much larger amounts from American Gas and Electric's system. It was testified, and the Commission agreed, that economies could be effected and service improved by coordinating Holston River's operation with Appalachian.

The holding company has been carrying out its policy of selling certain of its Pennsylvania subsidiaries. In September, 1947, it sold two of these to Pennsylvania Power

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[1] Federal Power Commission, Statistics, 1946, p. 75.

and Light Company, an independent which, until 1946, had been a subsidiary of National Power and Light, itself a subsidiary of Electric Bond and Share.[1] The service area of one of these was completely surrounded by, and all its electricity purchased from, Pennsylvania. The other adjoined Pennsylvania's service area. This company had its own steam plant and generated all its own energy, but an interconnection between the two was proposed, thus allowing the abandonment of this small, inefficient plant. It was again testified, and the Commission again agreed, that economies could be effected and service improved by so doing.

In 1950, Republic caused three of its remaining Pennsylvania subsidiaries to be merged, the name of the surviving company being changed to Cumberland Valley Electric company.[2] Thus, only three subsidiaries remained, and in December of that year, the Commission approved the sale of one of them to the Scranton Electric Company, an independent.[3] This subsidiary was a distributor only of electricity. Its service area adjoined both Scranton and another independent, Northern Pennsylvania Power Company, from which it purchased all its energy under a contract due to expire in 1955. Republic had

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[1] Holding Company Act Release 7749.

[2] Holding Company Act Release 10021.

[3] Holding Company Act Release 10292. Scranton had formerly been a subsidiary of American Gas and Electric.

negotiated with both companies for the sale of the property, and Scranton had made the best offer. The president of Republic testified that, upon the expiration or cancellation of the purchase contract, Scranton proposed to absorb the property and to interconnect and adapt it into the Scranton system, at an estimated cost of $300,000. The sale was in the nature of a liquidating dividend, as Republic received Scranton common stock in exchange for the property and distributed it to its stockholders.

Analysis

From the standpoint of plant economies, the result of application of the Act in this case is clearly all gain. As long as a very small operating company receives part or all of its energy from a large adjacent system, operating gains should accrue through integration of operations, and there is no economic justification whatsoever for a small company to generate its own energy when there is a neighboring large system. This record bears this out.

It may well be that, from an economic standpoint, Northern Pennsylvania should have acquired the company that Scranton bought, since they were already interconnected. There is not enough data to reach a judgment on this point, but it should be pointed out that the two companies involved evidently did not think so, since Scranton offered the better

price.[1] In any event, the Commission had no powers of persuasion whatsoever over either of these two operating companies, and Republic's sale to either was economically preferable to its retention of the property.

It is not possible to make any quantitative study of firm economies. The only one of the divested subsidiaries large enough to be in the Federal Power Commission data was Page Power, and this company was merged into a Potomac Edison subsidiary upon acquisition. The size of the two companies was so disparate that no conclusions can be drawn from the data of the companies before and after merger. However, since all of the companies which acquired properties from Republic were considerably larger than the combined properties of Republic, losses in firm economies cannot be anticipated.

Standard Gas and Electric Company

This company, together with its parent, Standard Power and Light Corporation, was originated and controlled by the late H. M. Byllesby. Prior to reorganization, this system had what has been called "the most complicated holding company set up."[2] It went into Section 77 B bankruptcy proceedings in 1935, which were terminated in 1938.[3] As of the

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[1] Of course, it is possible that other considerations than plant economies were involved in these decisions.

[2] Bonbright and Means, op. cit., p. 114.

[3] Moody's Manual, 1951.

end of 1938, its electric subsidiaries served an aggregate population of almost 5 million in 19 states and Mexico (see map).[1]

In the Section 11 (b) (1) decision,[2] the Commission called the system "an excellent example of what is not an integrated system." In this decision, the Company agreed to disposing of all properties except a single integrated system. The management of Standard view such action, "not merely as a means of compliance with the requirements of the Public Utility Holding Company Act of 1935, with which [it is] so often associated in the public mind, but also as a necessary and practical treatment of obvious corporate needs." The Commission found the system to consist of 9 of what it called "non-interrelated groups." They were: the Philadelphia Company and its subsidiaries, serving Pittsburgh and vicinity; Louisville Gas and Electric Company system, including the Madison, Indiana, property; Oklahoma Gas and Electric Company; Southern Colorado Power Company; San Diego Gas and Electric Company; California Oregon Power Company; Mountain States Power Company; the Northern States Power Company group, serving Minnesota and Wisconsin; Wisconsin Public Service Corporation and subsidiary.

Standard chose the Philadelphia Company system as its

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[1] Holding Company Act Release 1957.

[2] Holding Company Act Release 2929.

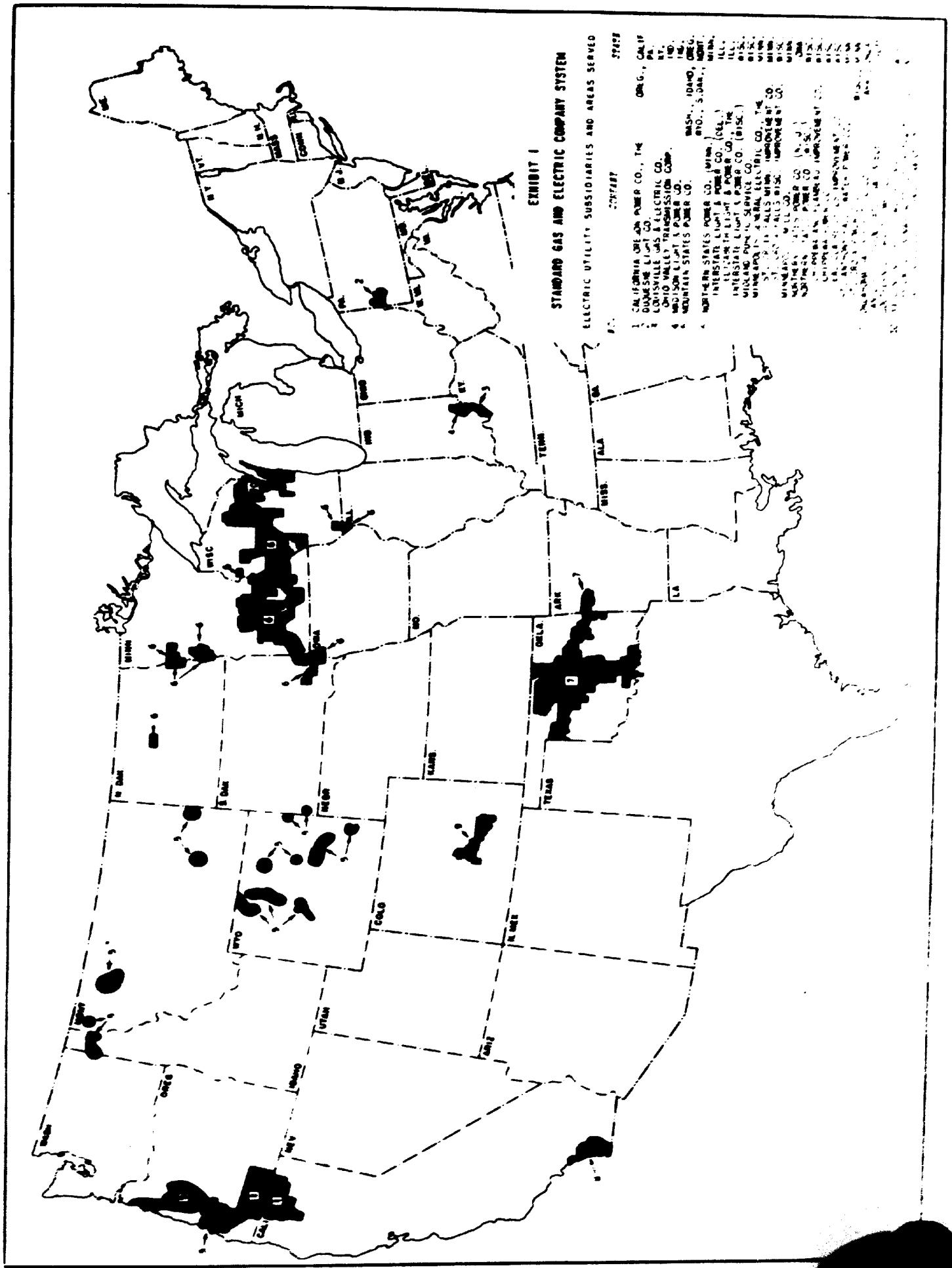
EXHIBIT I
STANDARD GAS AND ELECTRIC COMPANY SYSTEM
ELECTRIC UTILITY SUBSIDIARIES AND AREAS SERVED

single integrated system, and made no claim that any other property was retainable with it. The electric subsidiary of Philadelphia was the Duquesne Light Company. The Commission, without any discussion or question, found it to be an integrated system, since it was completely interconnected and was operated as a single system, with a central load dispatching office coordinating the five large steam generating plants. Its service area was quite small, but it served a population of 1 1/2 million.

Clause (B) excluded the rest of the properties except Louisville, and the Commission determined this not to be retainable with the Pittsburgh electric properties, since "the record shows that, including the Louisville properties, the operation of all the other groups of properties of the Standard Gas holding company system are separated from each other and from the Philadelphia Company." In addition, as noted, the system made no effort to show that it was retainable under the "ABC" standards and, in fact, did not wish to do so.

There were two sets of so-called non-interrelated properties which adjoined geographically: California Oregon and Mountain States, and Northern States and Wisconsin. There was "substantial" power interchange between each of these sets of properties. The Commission of course determined that neither group was retainable with the Pittsburgh Company; the question of whether they were retainable as independent

systems, was not raised, and as far as can be determined, the system presented no evidence relating to such retention.

Standard meant what it said about divestiture being a necessary and practical treatment of obvious corporate needs. Two months before the above decision, Standard exchanged its holdings of San Diego common for its own notes and debentures, and sold the remaining balance on the open market.[1] It lost control of several other subsidiaries through reorganization proceedings. Standard received 1 per cent of the common stock of the reorganized Southern Colorado[2] which it sold in 1949. At the end of the lengthy reorganization proceedings of the Northern States group, Standard received about 4 per cent of the common stock, which it sold.[3] During the course of the reorganization, the bulk of Northern States' subsidiaries were merged into it,[4] certain properties in Iowa and South Dakota were sold to the South Dakota Public Service Company,[5] and physical properties in North Dakota were disposed of to cities and cooperatives.

In 1944, the Madison, Indiana, property was sold to

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[1] Holding Company Act Releases 2262, 2483, 2841, 2872.

[2] Holding Company Act Release 4501.

[3] Moody's Manual, 1951.

[4] Holding Company Act Release 2903, and Moody's Manual, 1951.

[5] Holding Company Act Release 3004.

eight individuals.[1] Standard's holdings of Louisville stock were sold publicly; in 1949 the 13 per cent held directly by Standard was sold, and in 1950, the remaining system holdings (about 23 per cent of the total) were sold when Standard acquired them upon dissolution of a sub-holding company.[2]

Standard's holdings in California, Oregon and Mountain States, were sold publicly in 1947.[3] Hence, the system still controls Philadelphia and its subsidiaries, Wisconsin Public Service and Oklahoma Gas and Electric (in which it received about one-third of the common stock after reorganization). As soon as these are disposed of, Standard and its parent, Standard Power and Light, will dissolve. Standard has used the receipts from the above sales to retire its debentures and make other financial settlements.[4] The combined electric, gas and transportation properties of Philadelphia have been found to be not retainable by the Commission, and hence Philadelphia will dissolve, leaving Duquesne as the electric property in the Pittsburgh area.[5]

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[1] Holding Company Act Release 5282.

[2] Holding Company Act Release 9308, and Moody's Manual, 1951.

[3] Holding Company Act Releases 6707 and 7061. Standard held only 56 per cent of the common stock of the latter company.

[4] Holding Company Act Release 5070, and Moody's Manual, 1951.

[5] Holding Company Act Release 8242.

Analysis

No Commission order required the separation of any of the interconnected properties, and hence, application of the Act could not have resulted in the loss of any plant economies. Standard's holdings in Northern States became so small after its reorganization that there was no possibility of its integration with Wisconsin Public Service under Standard's aegis. Standard never asked to have the two west coast companies, California Oregon and Mountain States, found to be retainable together, which presumably means that integration wasn't desirable. As a matter of fact, these two companies have undergone no change in operating relationship. California Oregon has operated one of Mountain States' generating plants since 1929 under a 25-year contract, and it wholesales energy to Mountain States under a 30-year contract which expires in 1952.[1]

Apparently no great losses in firm economies were anticipated by the system. It does not appear that much help could be given the operating properties by the system, which needed to dispose of them to meet its financial problems. The former system service company became independent on January 1, 1948, and is now owned by the employees.[2] As far

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[1] Moody's Manual, 1951. This contract set very high, rigid rates; from 8 to 4 mills/kwh. on a step basis.

[2] Moody's Manual, 1951.

as can be determined, all former affiliates still use its services on request only. The company charges on a cost plus 10 per cent basis.

Table 19 shows what has happened to administrative and general expenses for those companies for which information is available. San Diego shows an average as a subsidiary of 5.3 per cent, and an average of 4.4 per cent as an independent, a decline of 17 per cent. Comparable averages for the other companies are as follows: California Oregon, 5.4 per cent and 6.2 per cent, an increase of 15 per cent; Mountain States, 4.9 per cent and 4.0 per cent, a decline of 18 per cent; Southern Colorado, 7.7 per cent and 7.3 per cent, a decline of 5 per cent; Northern States (Minnesota), 5.2 per cent and 4.6 per cent, a decline of 12 per cent; Northern States (Wisconsin), 6.4 per cent and 4.6 per cent, a decline of 28 per cent. Southern Colorado and Northern States became independent through Standard's losing their common stock equity in reorganization. Reorganization was completed in 1945 for Southern Colorado and 1948 for Northern States.

Part of the systems' holdings of Louisville were sold in 1949, the remainder in 1950. Thus, no comparisons are possible. The other three companies are still subsidiaries of Standard. The three remaining subsidiaries show no increase in this item even though the size of the holding company system has greatly declined; in fact, there is a marked downward trend in the averages for Duquesne and Wisconsin Public

TABLE 19

[illegible] SUBSIDIARIES OF STANDARD GAS AND ELECTRIC COMPANY
Administrative and General Expenses Excluding the
Pension Account as a Percentage of Gross
Electric Operating Revenue

[illegible] Electric Company	[illegible] Power Company	California Oregon Power Company	Mountain States Power Company	Northern States Power Company (Minnesota)	Northern States Power Company (Wisconsin)	Louisville Gas and Electric Company	Duquesne Light Company	Oklahoma Gas and Electric Company	Wisconsin Public Service Company
[illegible]	[illegible]	6.0	5.4	6.5	7.1	4.5	4.8	10.5	6.4
[illegible]	7.6	5.7	5.5	5.6	7.2	3.6	4.8	10.0	6.4
[illegible]	[illegible]	5.7	5.7	5.3	6.8	3.8	4.8	7.6	5.8
[illegible]	[illegible]	5.4	5.3	4.8	6.7	3.1	4.2	6.7	5.1
[illegible]	[illegible]	5.1	5.3	5.1	7.3	3.1	4.4	6.2	5.1
[illegible]	[illegible]	5.2	4.8	5.1	7.3	2.8	4.5	7.3	4.8
[illegible]	[illegible]	4.8	4.8	4.8	6.5	2.8	3.7	7.1	4.8
[illegible]	5.5[c]	5.1	4.4	5.0	6.8	3.1	3.6	7.8	4.8
[illegible]	[illegible]	5.1	4.1	4.7	6.3	3.4	4.3	6.2	5.3
[illegible]	[illegible]	5.3[c]	4.5[c]	4.3	4.8	3.3	3.6	6.3	4.4
[illegible]	[illegible]	5.1	4.1	4.2[c]	4.5[c]	3.1	2.6	6.6	4.3
[illegible]	[illegible]	5.3	4.1	4.3	4.1	3.1	2.7	6.1	4.3
[illegible]	[illegible]	5.5	5.3	4.3	5.2	3.2[c]	2.6	7.3	4.2

[illegible] Minneapolis General Electric Company and subsidiaries
[illegible] Northern States Power Company (Minnesota) on August
[illegible] data are adjusted to include both companies for the
[illegible] period.

[illegible] A subsidiary of Northern States Power Company
[illegible]

[illegible] Year changed.

as can be determined, all former affiliates still use its services on request only. The company charges on a cost plus 10 per cent basis.

Table 19 shows what has happened to administrative and general expenses for those companies for which information is available. San Diego shows an average as a subsidiary of 5.3 per cent, and an average of 4.4 per cent as an independent, a decline of 17 per cent. Comparable averages for the other companies are as follows: California Oregon, 5.4 per cent and 6.2 per cent, an increase of 15 per cent; Mountain States, 4.9 per cent and 4.0 per cent, a decline of 18 per cent; Southern Colorado, 7.7 per cent and 7.3 per cent, a decline of 5 per cent; Northern States (Minnesota), 5.2 per cent and 4.6 per cent, a decline of 12 per cent; Northern States (Wisconsin), 6.4 per cent and 4.6 per cent, a decline of 28 per cent. Southern Colorado and Northern States became independent through Standard's losing their common stock equity in reorganization. Reorganization was completed in 1945 for Southern Colorado and 1948 for Northern States.

Part of the systems' holdings of Louisville were sold in 1949, the remainder in 1950. Thus, no comparisons are possible. The other three companies are still subsidiaries of Standard. The three remaining subsidiaries show no increase in this item even though the size of the holding company system has greatly declined; in fact, there is a marked downward trend in the averages for Duquesne and Wisconsin Public

TABLE 19

DIVESTED SUBSIDIARIES OF STANDARD GAS AND ELECTRIC COMPANY
Administrative and General Expenses (Excluding the Pension Account) as a Percentage of Gross Electric Operating Revenue

Year	San Diego Gas and Electric Company	Southern Colorado Power Company	California Oregon Power Company	Mountain States Power Company	Northern States Power Company (Minnesota)[a]	Northern States Power Company (Wisconsin)[b]	Louisville Gas and Electric Company	Duquesne Light Company	Oklahoma Gas and Electric Company	Wisconsin Public Service Company
1938	5.5	6.4	6.6	5.4	6.5	7.1	4.9	4.8	10.5	6.4
1939	5.3	7.6	5.7	5.2	5.9	7.0	3.9	4.5	10.0	6.4
1940	5.1	8.6	5.7	5.7	5.3	6.5	3.5	4.5	9.8	5.8
1941	5.8[c]	8.1	5.4	5.0	4.8	6.7	3.1	4.6	8.7	5.2
1942	5.0	7.5	5.1	5.6	5.1	7.0	3.1	4.4	8.0	5.0
1943	4.5	7.2	5.2	4.5	5.0	7.0	2.9	4.4	7.3	4.9
1944	4.6	8.5	4.6	4.5	4.9	6.5	2.6	3.7	7.1	4.8
1945	4.0	8.5[c]	5.0	4.4	5.0	5.8	3.1	3.6	7.8	4.8
1946	4.2	6.7	5.6	4.0	4.7	5.3	3.4	4.5	8.2	5.3
1947	4.5	7.0	6.0[c]	4.5[c]	4.5	4.9	3.3	3.8	8.3	4.9
1948	4.0	7.5	6.0	4.1	4.2[c]	4.5[c]	3.0	2.8	8.5	4.6
1949	4.5	8.1	6.8	4.1	4.3	4.0	3.0	2.7	8.0	4.5
1950	4.6	7.1	5.9	3.9	4.8	5.2	3.2[c]	2.2	7.8	4.2

[a] Minneapolis General Electric Company and subsidiaries merged into Northern States Power Company (Minnesota) on August 29, 1941. Data are adjusted to include both companies for the whole period.

[b] A subsidiary of Northern States Power Company (Minnesota).

[c] Year divested.

Service. Oklahoma shows little change.

Comparing these declines with the national averages for the same years, there is no indication of loss of firm economies.[1]

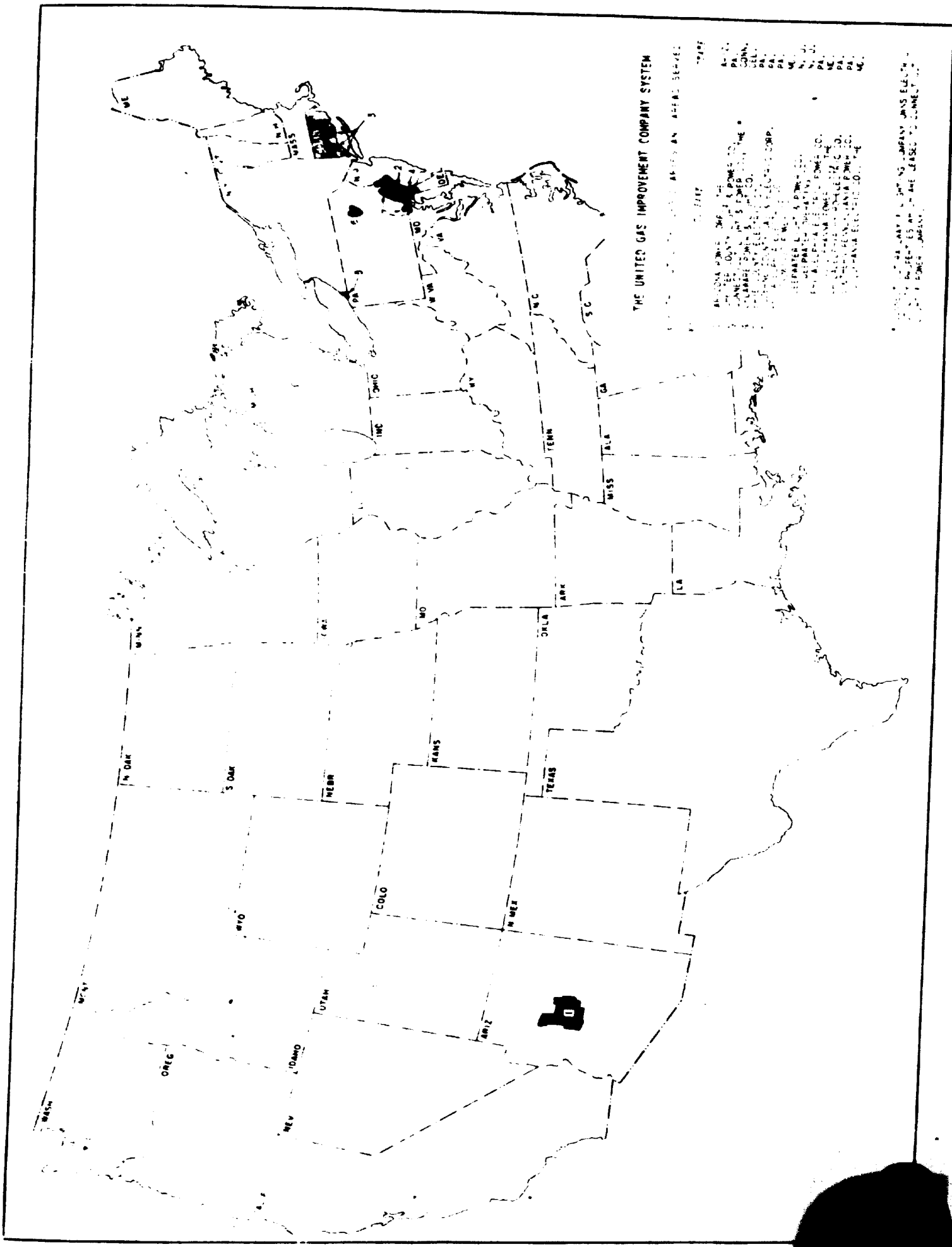
The United Gas Improvement Company System

In spite of its name, this system was composed, in 1940, mainly of electric and combined electric and gas subsidiaries. Section 11 (b) (1) hearings were instituted in March, 1940.[2] During the course of the hearings, United Gas requested a statement of tentative conclusions as to the actions the Commission believed necessary to meet the requirements of this action. The Commission obliged in January, 1941.[3] It concluded tentatively that the single integrated system to which United Gas should be limited was electric properties of Philadelphia Electric Company and subsidiaries, Chester Company Light and Power Company and Delaware Power and Light Company. This interconnected system, located in southeastern Pennsylvania and adjacent portions of New Jersey, Maryland and Delaware (see map), was about 80 by 30 miles in area and served a population of nearly 3 million. The aggregate book value of these properties was more than 350 million dollars and in 1939 the electric operating revenues totaled

[1] See Appendix.

[2] Holding Company Act Release 1953.

[3] Holding Company Act Release 2500.


THE UNITED GAS IMPROVEMENT COMPANY SYSTEM
MINN
WASH
OREG
IDAHO
NEV
UTAH
ARIZ
N MEX
COLO
WYO
N DAK
S DAK
NEBR
KANS
OKLA
TEXAS
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MISS
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MICH

168 million dollars.

The Commission concluded that clause (B) prohibited the retention of electric properties in Arizona and Connecticut, as well as gas and other properties in New Hampshire, Tennessee and Kansas. It also tentatively concluded that clauses (A) and (C) would not allow retention of the other two Pennsylvania electric properties, Erie County Electric Company and Lucerne County Gas and Electric Corporation, as added systems, nor could the gas properties of Philadelphia Electric be retained. Immediately thereafter, United Gas sold the stock of the Connecticut Light and Power Company publicly.[1]

United Gas raised the question of whether, under the Act, both gas and electric companies were, or could be, a single integrated system. On April 15, 1941, the Commission answered in the negative.[2] One might be retainable with the other only as an additional system if the "ABC" requirements were met. United Gas appealed this decision to the courts, but the Commission's interpretation was upheld.[3] Upon meeting this rebuff, United Gas submitted a Section 11 (e) (voluntary)

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[1] Holding Company Act Release 2687, April 9, 1941.

[2] Holding Company Act Release 2692. With the possible exception of the American Water Works case (which see), the Commission has maintained this interpretation without exception.

[3] 138 F (2d), 1010 (1943).

plan to the Commission, although no definitive Section 11 (b) (1) decision had been reached.[1] At the time of the decision on this voluntary plan,[2] the consolidated total assets of the United Gas system totaled nearly 760 million dollars,[3] two-thirds of which accrued from the Pennsylvania-Maryland-Delaware cluster of properties. United Gas' subsidiaries received 107 million dollars in operating revenues in 1942, 84 per cent of which was received by the above cluster of companies.

United Gas' plan was to distribute the stock of Philadelphia Electric to its stockholders (and also that of Public Service of New Jersey) as a partial liquidating dividend. No reason was given for the apparent decision to liquidate United Gas. The Commission undertook to determine the effects on Philadelphia Electric of such separation. On the basis of the testimony of United Gas' directors, among others, the Commission found that

> the establishment of active markets through this wide distribution [of Philadelphia Electric's stock to United

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[1] In Holding Company Act Release 2692, United Gas had been ordered to divest those properties precluded by clause (B). The only electric property involved was Arizona Power Corporation.

[2] Holding Company Act Release 4173, March 18, 1943.

[3] Not consolidated in this figure were the 742 million dollar assets of Public Service of New Jersey. This company was legally United Gas' subsidiary, but United Gas owned considerably less than 50 per cent of Public Service's stock. This stock was distributed to United Gas stockholders at the same time as Pennsylvania Electric's was.

> Gas stockholders] would afford Philadelphia Electric a better opportunity to do its own junior financing. In this connection, there seems little question that Philadelphia Electric can finance itself upon much more favorable terms than United Gas could render such financial aid through the sale of its own securities.

Also, the distribution would

> in no way affect the contractual obligations of Philadelphia Electric [such as the purchasing, and the sale and interchange of energy] or physical operation of Philadelphia Electric, nor would it result in any additional expense to Philadelphia Electric other than expenses incident to dealing with an enlarged list of stockholders.

The Commission thus approved the separation of the principal part of what it had felt to be the principal system of United Gas, since it appeared that no loss of economies would result.

In 1945, United Gas sold Chester County Light and Power Company to the now independent Philadelphia Electric Company.[1] This company's service area was surrounded on all sides except the southeast by the Philadelphia Electric system. There, it was bordered by Delaware Power. Chester was not directly connected with Philadelphia Electric, but received substantially all of its energy from it indirectly through the facilities of Delaware Power which did not operate in the state of Pennsylvania. (It will be remembered that all three companies had been tentatively concluded by the Commission to be the main integrated system of United Gas.) It was planned to interconnect the two companies directly, and

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[1] Holding Company Act Release 5751.

to merge Chester with a subsidiary of Philadelphia Electric. This integration of facilities would give rise to savings estimated at 30 to 40 thousand dollars per year. Pending the completion of the postwar construction program, Philadelphia Electric proposed to negotiate a change of contract with Delaware Power so that it could sell energy directly to Chester over Delaware Power's facilities. The acquisition was approved under Section 10 (c) (2).

In 1944, United Gas distributed the stock of Delaware Power as another partial liquidating dividend.[1] Before this was done, United Gas traded electric operating properties with the Associated Gas and Electric system.[2] Associated Gas and Electric was under Commission order to dispose of Eastern Shore Public Service Company. United Gas had not been ordered to dispose of Erie County Electric Company, but it seemed likely that it would be. These two properties were exchanged.[3] Eastern Shore served electricity to about 40,000 customers in the parts of Delaware, Virginia and Maryland known as the Delmarva peninsula (see Associated Gas and Electric Company map above, p. 42). The territory, 160 miles in length by 15-60 miles in width, is primarily rural in character. The

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[1] Holding Company Act Release 4784.

[2] Holding Company Act Release 4505.

[3] As noted previously, Erie was practically surrounded by the subsidiary of Associated which acquired it. See the Associated Gas and Electric Company, above, pp. 44-45.

main service area of Eastern Shore adjoined Delaware Power on the north. In addition, a subsidiary of Eastern Shore served electricity to a portion of Maryland on the west side of Chesapeake Bay, beginning 10 miles south of Washington, D. C. This part was of course not connected with the main body of Eastern Shore, and it purchased nearly all of its power requirements from the Potomac Electric Company.

Some savings were anticipated by operating Delaware and Eastern Shore as a group. Eastern Shore, which was separated by water from contact with lines of any other system except Delaware, was a self-contained, integrated unit. It was expected that the postwar period would find Eastern Shore short of power. United Gas engineers had considered the two possibilities, namely, interconnecting with Delaware and enlarging its main plant. A 66 kv. interconnection from Wilmington to Eastern Shore's lines at Greenwood, a distance of 68 miles, would cost about $1,035,000, while installation of a 7500 kw. generator in its generating plant would cost around $1,540,000. The interconnection would not only give an alternative source of power, and hence make service more dependable, but would result in average annual savings of $30,000 in generating costs for the period 1943-1952, based upon continuance of the then present price that Delaware paid Philadelphia Electric for its power.[1] It was said that this

[1] At this time, substantially all of Delaware's power was bought from Philadelphia Electric.

figure was arrived at on the basis of a larger generator being built than would be required immediately, and hence, "the investment in the unit would be utilized only as the load increased." The Commission pointed out that the two companies had different peak load times.

Administrative savings of $34,000 annually were also expected. Eastern Shore was currently purchasing engineering, tax and accounting services to that amount, and Delaware expected to be able to supply these by its staff without additional cost.

The acquisition was approved and Eastern Shore was merged into Delaware. Later, Delaware sold the Eastern Shore property south of Washington, D. C., to the Southern Maryland Electric Cooperative.[1] In the same year, Arizona Power was also sold. An individual who owned the Arizona Electric Power Corporation proposed to purchase this company and to merge the two. The two properties were contiguous and interconnected, Arizona Power supplying Electric with a substantial portion of its energy. The individual estimated that "numerous operating economies" would result from the merger, although no specific amounts were named. The proposal had been approved by the Arizona commission, and it was approved by the SEC under Section 10 (c) (2), although one of the Commissioners dissented.[2] He approved the merger but questioned

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[1] Holding Company Act Release 5694.

[2] Holding Company Act Release 5882.

proposed methods of financing it.

According to a statement in the 1951 Moody's Public Utility Manual, United Gas now intends to remain as a holding company system in the gas field. It still controls Luzerne County Gas and Electric Corporation, as well as other gas properties in Pennsylvania. The question of the disposition of Luzerne has not yet been settled.

Analysis

Since the Commission did not order the separation of any interconnected subsidiaries, application of the Act resulted in no losses of plant economies. While Delaware was separated from Philadelphia Electric and Chester County, United Gas requested this move, and the Commission allowed it only after assuring itself that no losses in economies were anticipated. The interconnections between the two sets of properties still exist, and Delaware still depends upon Philadelphia Electric for practically all of its energy requirements. The record indicates that the companies could have been kept together as a unit if United Gas had so desired.

The transfer of properties between United Gas and Associated Gas and Electric resulted in the gain of plant economies. The acquisition of Erie County Electric by Pennsylvania Power eliminated duplication of generation, transmission and distribution facilities in and around Erie, Pennsylvania, while the acquisition of Eastern Shore by

Delaware should have resulted in decreased operating and capital costs due to its inclusion into Philadelphia Electric's large generating facilities. Savings should also accrue to Arizona Power through its amalgamation with an adjacent, interconnected property.

There was nothing in the record to indicate loss of firm economies upon separation of subsidiaries from United Gas. Indeed, the Commission felt that separation of Philadelphia Electric would result in gains, so far as capital costs were concerned, and that there would be no losses of any kind in this case.

Table 20 shows, for those former subsidiaries for which data are available, what has happened to those firm costs which are included in administrative and general expenses. Connecticut Power and Light shows an average of 6.4 per cent for the years prior to separation, and 6.2 per cent after separation, a decline of 3 per cent; Delaware had an average of 3.8 per cent prior to separation and 3.7 per cent afterwards, a decline of 3 per cent; Chester County, acquired by, but not merged with, Philadelphia Electric in 1945, shows a marked decline after separation. The averages are 6.2 per cent before separation and 2.5 per cent after separation, a decline of 60 per cent. Philadelphia Electric itself, by far the largest of the former subsidiaries, shows an increase of 6 per cent after separation, with averages of 3.3 per cent before separation and 3.5 per cent after separation.

TABLE 20

DIVESTED SUBSIDIARIES OF UNITED GAS IMPROVEMENT COMPANY
Administrative and General Expenses (Excluding the Pension Account) as a Percentage of Gross Electric Operating Revenues

Year	Connecticut Power and Light Co.[a]	Delaware Power & Light Co.[b]	Chester Co. Light & Power Co.	Philadelphia Electric Co.	Luzerne Co. Gas and Electric Corp.
1938	6.6	5.5	---	3.2	4.0
1939	6.3	4.6	6.5	3.3	5.5
1940	6.2	3.5	6.2	3.3	3.2
1941	5.9[c]	3.0	5.9	3.3	3.9
1942	6.3	3.2	5.9	3.4	2.8
1943	6.1	3.0	7.0	4.3[c]	3.3
1944	5.8	4.6[c]	5.8	3.5	2.7
1945	6.1	4.4	3.7[c]	3.9	2.4
1946	6.8	4.1	2.4	3.4	2.5
1947	6.5	3.8	2.5	3.4	2.5
1948	6.2	3.4	2.6	3.5	2.6
1949	6.3	3.2	2.7	3.7	2.6
1950	6.1	3.2	2.4	3.4	2.4

[a] From 1941-1950, the "rents" item (line 134) included about $325,000 annually of undistributed rent for plant leased from others. Since this is properly a production expense, it has been excluded from the administrative and general expense account total.

[b] Acquired Eastern Shore Public Service Company on October 15, 1943. Previous years' data adjusted to include Eastern Shore with Delaware.

[c] Year divested.

Luzerne County, which is still a subsidiary of United Gas, seems to show a decrease in these firm costs over the period, even though the size of the system has become markedly smaller.

However, comparing changes in administrative and general expenses for United Gas' former subsidiaries with the national averages for the same periods, losses of firm economies here are indicated.[1]

If the claim made by Delaware that $34,000 annually could be saved in administrative costs by the merger of Eastern Shore into it is correct, it would appear that separation of Associated Gas and Electric's subsidiary from it did not result in loss of firm economies.

United Light and Power Company (United Light and Railways Company)

At the end of 1938, this system served electricity to areas with an aggregate population of slightly less than 2 million in eleven states (see map).[2] The consolidated book assets of the system on December 31, 1940, were nearly 600 million dollars.[3]

In 1941, at the request of United Light and Power, the Commission issued its tentative conclusions as to what the

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[1] See Appendix.

[2] Holding Company Act Release 1961.

[3] Holding Company Act Release 2636. No breakdown is available as between electric and gas property.

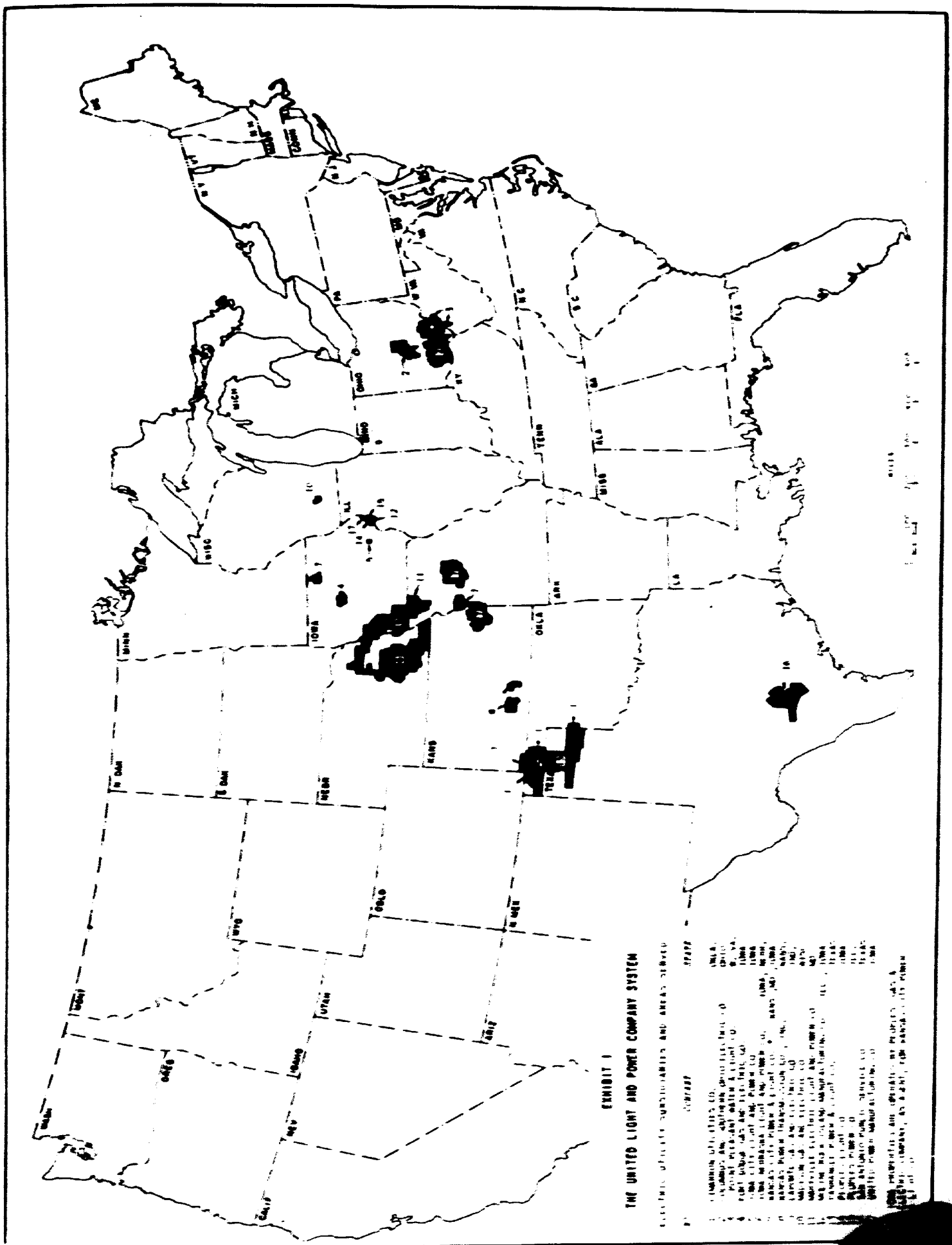
EXHIBIT 1
THE UNITED LIGHT AND POWER COMPANY SYSTEM

system must do to comply with the integration provisions of the Act.[1] The conclusions were based entirely upon the one area interpretation of clause (B). A vice-president of United Light and Power had testified that the system considered the Kansas City Power and Light Company to be the principal system which it wished to retain. This seemed reasonable to the Commission, since it was the largest operating company in the system. On the basis of its tentative examination, it concluded that Kansas City was an integrated electric system (except for the isolated properties in Morton County, Kansas, and in northern Iowa). On the basis of clause (B), therefore, the properties in Ohio, West Virginia, Indiana and Texas were concluded not to be retainable.[2] The Commission felt that this decision as to clause (B) might facilitate solution of problems arising under clauses (A) and (C):

> Our opinion in this respect is based in part upon the possibility of changed circumstances in the event that the holding company system should transfer its principal base of operations to Kansas City; upon the possibility that the holding company system as so limited may acquire other properties in the Kansas City area, the acquisition of which might change the nature of the problem presented under clauses (A) and (C); and upon the possibility that the holding company system may voluntarily dispose of some of these properties.

Later the same year, the tri-cities properties: Moline-

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[1] Holding Company Act Release 2820.

[2] Their disposal was ordered in Holding Company Act Release 2923.

Rock Island Manufacturing Company, Peoples Light Company, Peoples Power Company, and United Power Manufacturing Company (the latter the separate Iowa properties) were merged into a new company, Iowa-Illinois Gas and Electric Company.[1] These so-called "first lien" companies had all been direct subsidiaries of United Light and Power. The parent company was then dissolved, and United Light and Railways Company became the top holding company in the system. The merger did not affect the Section 11 (b) (1) questions not yet decided, but the Commission did note that the electric assets in the tri-city area were interconnected and appeared capable of being operated as an integrated electric system.

The system set out to acquire adjacent companies.[2] In 1942, Eastern Kansas Utilities was acquired from the Community Power and Light system.[3] As may be seen on the map of this three-state area, Eastern was adjacent to Kansas City Power and Light. The two companies were interconnected at several points and Eastern purchased about one-third of its energy requirements from Kansas City.[4] Eastern served about 10,000 customers,

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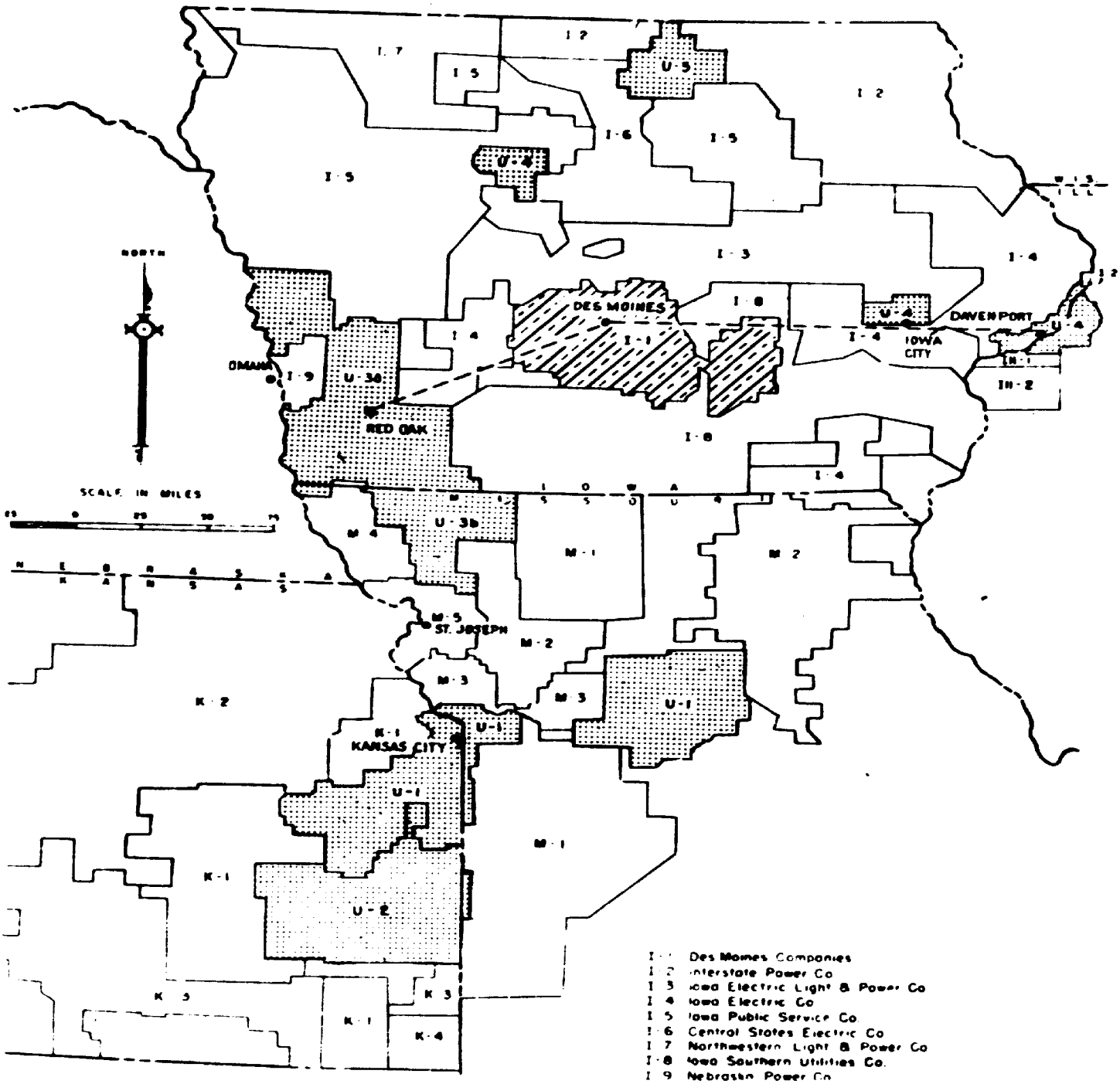
[1] Holding Company Act Release 3242.

[2] As will be seen later, the plan was to develop an integrated system in the Iowa-Missouri-Kansas area.

[3] Holding Company Act Release 3666.

[4] It purchased about one-fourth from Kansas Gas and Electric Company, a non-affiliate, and generated the rest itself.



I-1 Des Moines Companies
I-2 Interstate Power Co
I-3 Iowa Electric Light & Power Co
I-4 Iowa Electric Co
I-5 Iowa Public Service Co
I-6 Central States Electric Co
I-7 Northwestern Light & Power Co
I-8 Iowa Southern Utilities Co.
I-9 Nebraska Power Co

III-1 Sherrard Power System
III-2 Illinois Northern Utilities Co.

U-1 Kansas City Power & Light Co.
U-2 Eastern Kansas Utilities, Inc
U-3a Iowa Nebraska Light and Power Co
U-3b Maryville Electric Light and Power Co
U-4 Iowa Illinois Gas and Electric Co.
U-5 Peoples' Gas & Electric Co.

M-1 Missouri Public Service Co
M-2 Missouri Power & Light Co
M-3 Missouri Gas & Electric Service Co.
M-4 Missouri Service Co
M-5 St. Joseph Ry, Light, Heat & Power Co

K-1 Kansas Electric Power Co.
K-2 Kansas Power & Light Co.
K-3 Kansas Gas & Electric Co
K-4 Empire District Electric Co

ELECTRIC SERVICE AREA MAP OF IOWA AND SURROUNDING TERRITORY

AS OF DECEMBER 31, 1942

mostly rural. Because of the service area's proximity to Kansas City's principal generating plants in that city, it was stated that the acquisition would result in "advantages" to investors and consumers in both companies. The Commission decided that, "some operating savings will be realized immediately and additional savings are estimated to be realizable from future development in power supply and system operation." The acquisition was approved under Section 10 (c) (2).

A little over a year later, the system asked the Commission to approve its acquisition of Des Moines Electric Light Company and Iowa Power and Light Company from the North American Company, which was under Commission orders to dispose of them.[1] United Light and Railways stated that the purchase was "a major step in the consummation of a well-defined program designed to bring the [holding company system] into compliance with Section 11 (b) (1) of the Act." The proposed system was to extend from the tri-city area across Iowa and into northwestern Missouri and southeastern Kansas (see map of the three-state area). It was United Power and Light's intention to interconnect by high voltage lines all of these properties and to operate them as a "single integrated system." In addition, it was planned to add to this system, by later purchase,

utility assets of companies serving communities in

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[1] Holding Company Act Release 4497.

territories intervening or adjacent to the territories served by the properties named, including, among others, the utility properties in and around St. Joseph, Missouri, and part or all of the properties of Iowa Electric Company and Iowa Southern Utilities Company, located in the territory bordering on the service area of the Des Moines Companies.

It was argued that the acquisition of these properties from North American was the key to effecting the proposed interconnection because of their location. United Light and Railways presented evidence, prepared by independent engineers retained for the purpose, to show the operational economies anticipated from interconnecting these properties and operating them as a unit.

Even though particular emphasis was placed on the inclusion of Kansas City in the proposed integrated system, the Commission did not deem it necessary to determine whether acquisition of the Des Moines properties was permissible in relation to those in Kansas City under Section 10 (c) (2). It felt the record showed that economies would be obtained by interconnecting Des Moines, Iowa City and the tri-cities, and by connecting Des Moines and Iowa-Nebraska Power without interconnecting Des Moines with Kansas City. It was estimated that making the former interconnection by means of 160 miles of 132 kv. line would give production savings of $960,900 over an 8-year period, and "savings in fixed charges at 11 1/2% on investment,"[1] of $219,900 over the same period,

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[1] The 11 1/2 per cent figure was arrived at as follows: "taxes, 1 1/4%, depreciation 3%, interest 6%, insurance 1 1/4%." The meaning of all this is not clear. It would appear that

or an average of $147,600 of annual savings.

A 99-mile 66 kv. line from Des Moines to Red Oak, in Iowa-Nebraska's territory, and combining the operations of Des Moines and Iowa Power and Light, would give estimated annual savings of $160,560, on the basis of savings of $20,800 in executive and administrative costs, $37,500 in "general and commercial" costs, and $32,760 in reduction of physical plant payroll, in the combined operation of the two companies proposed to be acquired. There would also be $69,500 of annual "interconnection" savings--presumably operating savings over and above the interconnection cost.

As may be seen on the map, the state of Iowa was served by a large number of small utilities which, according to the Commission, had small generating capacities and a "noticeable lack" of interconnection, and hence, energy costs were high. Interconnection in general would reduce costs, "principally by reason of savings arising from a reduction in necessary capacities and the more efficient loading of generators."[1]

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the interconnection cost would be an offset to production savings, unless it reduced the need for capital expenditure for generating capacity by more than its cost. In this case, the use of the 11 1/2 per cent multiplier on total capital savings would appear to give an annual savings figure.

[1] In addition, larger generating units could be used in the future, although the Commission did not note this source of plant economy.

The proposed acquisition would mean that this system in Illinois and Iowa would have a total of 55.1/2 million dollars in electric plant and property, with gross revenues of about 14 million dollars,[1] and it would serve areas with a total population of 430,000.[2]

The Commission approved the acquisition of the Des Moines companies, but it stated that such approval did not mean that both the Kansas-Missouri properties and the Illinois-Iowa properties might be retained together. It expressly reserved jurisdiction on the Section 11 (b) (1) question. Permission was also granted for Iowa Power and Light to absorb the properties of Des Moines Electric and the Iowa properties of Iowa-Nebraska by intrasystem exchanges.[3]

In 1945, United Light and Railways completed negotiations with Cities Service for the purchase of St. Joseph Railway, Light, Heat and Power Company and asked the Commission for its approval.[4] As noted in the previous case, this

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[1] Based on 1942 data.

[2] Kansas City Power and Light Company, and the small Eastern Kansas Utilities, both almost exclusively electric properties, had total assets of about 103 million dollars and gross revenues of 19.5 million dollars.

[3] The Nebraska electric properties of Iowa-Nebraska had been sold in 1941 to the Nebraska Consumers Public Power District. After the above transaction, Iowa-Nebraska's only remaining assets were gas properties in Nebraska, which were sold to Central Electric and Gas Company in 1945. Holding Company Act Release 5619.

[4] Holding Company Act Release 5943. See above, pp. 69-73.

acquisition was part of the system's plan to develop an integrated system in this general area. As the three-state map shows, St. Joseph was close to Kansas City and Power and Light's service area.[1] It was contiguous with and interconnected with the Maryville property of United Light and Railways, and sold power at wholesale to it. St. Joseph's entire supply of energy was produced in one generating plant, which had a capacity of 33,100 kw. The territory served had a total population of 110,000.

Upon acquisition of St. Joseph, the system proposed to interconnect it with Kansas City Power and Light by a 132 kv. line and coordinate the operation of the companies. Not only would savings be obtained in this way, but St. Joseph's capacity was currently insufficient to meet its requirements and the interconnection would obviate the necessity of installing a new 10,000 kw. generator unit in the St. Joseph generating plant. The Commission found this acquisition permissible under Section 10 (c) (2), but it pointed out that the economies would be obtained regardless of whether the Kansas-Missouri properties were interconnected with or retainable with those in Illinois and Iowa.

The system meanwhile was complying with the Commission's Section 11 (b) (1) divestment order. In 1941, Kansas Power Transmission Company was sold to Western Light and

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[1] They were 18 miles apart at the closest point.

Telephone Company.[1] Point Pleasant water and Light Company was acquired by, and merged into, Appalachian Power Company, a subsidiary of American Gas and Electric Company.[2] San Antonio Public Service Company was sold to that city.[3] Cimarron Utilities Company and Panhandle Power and Light Company, along with the Morton county properties of Kansas City were sold to Community Power and Light Company.[4] In 1946, the stock of Columbus and Southern Ohio Electric Company was sold publicly, and Wisconsin was disposed of the same way in 1949.[5]

In 1944, LaPorte Gas and Electric Company was sold to Northern Indiana Public Service Company.[6] Some information is available on the effects of this sale. Northern Indiana, then a subsidiary of the trustees of Midland Utilities Company,[7] bounded LaPorte on three sides; Indiana and Michigan,

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[1] Moody's Manual, 1942.

[2] Holding Company Act Release 3688.

[3] Holding Company Act Release 3870.

[4] Holding Company Act Releases 3667 and 4937. See above, pp. 234-235.

[5] Holding Company Act Release 6621. The Commission had not allowed American Gas and Electric to acquire Columbus and Southern Ohio. See Electric Bond and Share, above, pp. 106 ff.

[6] Holding Company Act Release 4740.

[7] Midland Utilities was formerly a part of the Insull holdings.

a subsidiary of American Gas and Electric, bounded it on the northeast. Ninety per cent of LaPorte's energy requirements were obtained from Indiana and Michigan over two 33 kv. ties at the New Carlisle substation, 15 miles from LaPorte, an interchange point between the 132 kv. transmission systems of Northern Indiana and Indiana and Michigan. The rest of its power it generated in its own plant--used mostly for stand-by--which only operated when it supplied exhaust steam for heating purposes in LaPorte. Northern Indiana expected to assume LaPorte's power purchase contract with Indiana and Michigan and to continue the existing purchase arrangements. LaPorte was a relatively small company, with operating revenues in 1943 of about $1,000,000, compared with $29,000,000 for Northern Indiana. Savings of "at least $20,000 annually" were expected from the acquisition.

Although the initial Commission order had been substantially complied with, the question of whether the remaining properties were an integrated system within the meaning of the Act had not yet been determined. It never was, since the management of United Light and Railways decided to dismantle the system.

By 1948, a high-voltage transmission line interconnected all the companies of the system.[1] Each operating

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[1] The two isolated properties in northern Iowa were not interconnected with any of the rest.

company had constructed and owned the portion of the line in its service area. The companies had signed a contract providing that the line and other necessary facilities would be the basis of a 25-year power pool arrangement. The power pool agreement provided that energy was to be interchanged among the companies on the basis of "cost of production," adjusted for contributions to the power pool by each company of generation and transmission facilities. Even so, the system feared that determination of this question might result in the compulsory segregation of the properties of the major subsidiaries. In addition, the president of United Light and Railways testified that "the major operating utility companies in the system could finance their extensive construction programs with the sale of their own securities directly to the public more advantageously than the holding company could market its own common stock and furnish funds to such subsidiaries." Therefore, a voluntary program of dissolution of the parent companies (United Light and Railways and a subsidiary holding company) was felt appropriate by the management, not only to solve the Section 11 (b) (1) problems, but also as a benefit to the operating companies themselves. The Commission was asked to approve this plan.

It did so. The Commission felt that no operating economies would be lost by such dissolution:

> While the electric properties have been physically integrated since July, 1948, it appears .... that such

> interconnection was for the purpose of permitting a type of power pool operation which can be effectuated through contractual arrangements among the operating companies. The record is barren of any indication or claim of the type of integrated operation which we have held to justify the continuation of a holding company to perform the integration function. [Citation of HCAR 8889. See Electric Bond and Share, above, pp. 131-132.] The judgment of the management to liquidate supports the negative finding impelled by the record.....

The stocks of all the subsidiaries were distributed in 1950 to the stockholders of United Light and Railways as liquidating dividends.[1] Thus, Iowa-Illinois, Kansas City, Iowa Power and Light, St. Joseph[2] and Eastern Kansas are now all independent operating companies, bound together only by the power pool agreement.

Analysis

It is clear that none of the properties divested under Commission order lost plant economies. Very probably most of them gained in this respect. The Morton County property of Kansas City Power and Light, Panhandle Power and Light and Cimarron Utilities were all interconnected,[3] but they were sold to and integrated into what is now Southwestern Public Service Company with probable resultant economies due to the larger operational unit. This same point can be made for

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[1] Holding Company Act Releases 9587 and 9989. The stock of Madison Gas and Electric Company was distributed as a partial liquidating dividend in 1949 (Holding Company Act Release 9089).

[2] St. Joseph absorbed Maryville Electric in 1947.

[3] Holding Company Act Release 3667.

American Gas and Electric's acquisition of Point Pleasant, Western Light and Telephone's acquisition of Kansas Power and Northern Indiana Public Service's acquisition of LaPorte. Although originally it might have been more desirable economically for LaPorte to be acquired by American Gas and Electric's subsidiary, since it supplied the bulk of LaPorte's energy, American Gas and Electric did not bid on the property, perhaps because its Section 11 (b) (1) case had not yet been decided. In any event, the Commission has only permissive power in such cases. American Gas and Electric could not be compelled to buy the property. LaPorte's operation has since been interconnected and integrated into Northern Indiana Public Service's system.

The sale of San Antonio to that city and Columbus and Southern Ohio to the general public should not have affected their plant economies in any way. The fact that the Des Moines companies, St. Joseph and Eastern Kansas were acquired from other systems and became parts of a larger operating unit should have resulted in gains, as the testimony indicates. Gains should have resulted also to the system's original properties due to the interconnection made possible by the acquisition of the above companies.

The effect of dismantling the system upon the subsidiaries' plant costs is not easy to assess. The question must be raised whether, in fact, the existing operational set-up of the system companies in the three-state area was indeed

different than that of Middle South Utilities. It is quite possible that continuing holding company ownership would have given rise to additional economies over and above those obtained by the power pool contracts. However, if this were true, United Light and Railways would have had a good case to present to the Commission to allow all the subsidiaries to be retained under its control as an integrated system. The group was not nearly as large as others found to meet the standards of the Act, and there was precedent to allow the system's operating territory to be divided by intervening foreign service areas.[1]

There is no evidence to indicate that the break-up of the Kansas-Missouri-Iowa system did result in loss of plant economies. Further, it should be remembered that the Commission did not order it dismantled. This was the company's decision.

The question of whether the properties divested under Commission order lost firm economies is impossible to answer for a number of the companies, because they became governmentally owned or were merged into larger units with the resultant impossibility of isolating any changes caused by divestment from United Light and Railways. Only two of the divested companies did not lose their identities, and the

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[1] For example, see American Gas and Electric, above, pp. 101 ff.

data for them are shown in the following table:

TABLE 21

DIVESTED SUBSIDIARIES OF UNITED LIGHT AND RAILWAYS COMPANY
Administrative and General Expenses (Excluding the Pension Account) as a Percentage of Gross Electric Operating Revenue

Year	Columbus and Southern Ohio	Madison Gas and Electric
1938	4.2	3.0
1939	3.7	3.4
1940	3.7	3.4
1941	4.0	2.9
1942	4.3	3.0
1943	4.2	3.0
1944	3.7	3.2
1945	3.4	2.6
1946	3.8[a]	2.7
1947	3.8	2.7
1948	3.8	2.6
1949	4.2	3.0[a]
1950	4.7	2.8

[a] Year divested.

The average for Columbus and Southern Ohio as a subsidiary is 3.9 per cent and as an independent, 4.1 per cent, an increase of 5 per cent. The average for Madison as a subsidiary is 3.0 per cent. Only one full year of independence, 1950, is shown. The figure for that year is 2.8 per cent, a decline of 7 per cent.

Comparing these changes with changes in the national

averages for the same periods,[1] it appears that one company lost firm economies and the other did not. The sample is not large enough to generalize for the system as a whole.

The effects on the system companies divested because of the dissolution of United Light and Power are not yet determinable, since the dissolution occurred in 1950. If there are any losses after 1950, it is not clear that they should be considered as an effect of application of the Act, since the action was voluntary. It should be remembered also that part of the reason given for dissolution was to enable the operating companies to obtain capital at lower cost.

It was not felt possible to make any meaningful study of the effects on the remaining subsidiaries' firm costs after divestment of those subsidiaries required by the Act. The size of the system, in terms of electric utility plant, increased from 216 million dollars in 1942 to 231 million dollars in 1946, since the companies acquired by the system were larger than those divested.[2] Only after the divestment of Columbus and Southern Ohio, in the latter year, did the electric utility plant of the system become smaller than in 1942, dropping to 173 million dollars, a decline of slightly

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[1] See Appendix.

[2] Based on data in Statistics, 1942-1946. This increase was not due to the growth of individual companies. Growth of companies remaining in the system was negligible, in net terms, over the period.

less than 20 per cent of the original figure. It would not appear, however, that there should be any marked change in firm costs for the period as a whole, because of the relatively small net change in size of the system.

United Public Utilities Corporation

United Public Utilities, one of the smallest systems to which Section 11 (b) (1) was applied, consisted of 19 subsidiaries in 1940, thirteen of which were public utilities within the meaning of the Act.[1] Eight of these were electric companies. The combined book assets of the system as of December 31, 1940, were slightly more than 22 1/2 million dollars. The electric properties were in two separate areas: in North and South Dakota, and Indiana and Ohio (see map).

In 1941, the Commission tentatively concluded that retention of both of the above sets of properties was precluded by clause (B), and that in addition, the other properties (gas and ice companies) in the South could not be retained.[2] United Public Utilities did not concede the Commission's interpretation of clause (B) (the single area interpretation) but stated:

> we are making no contention that the retention of [the southern companies] is necessary to prevent the loss of substantial economies, so that even though the Commission's interpretation of the requirements regarding

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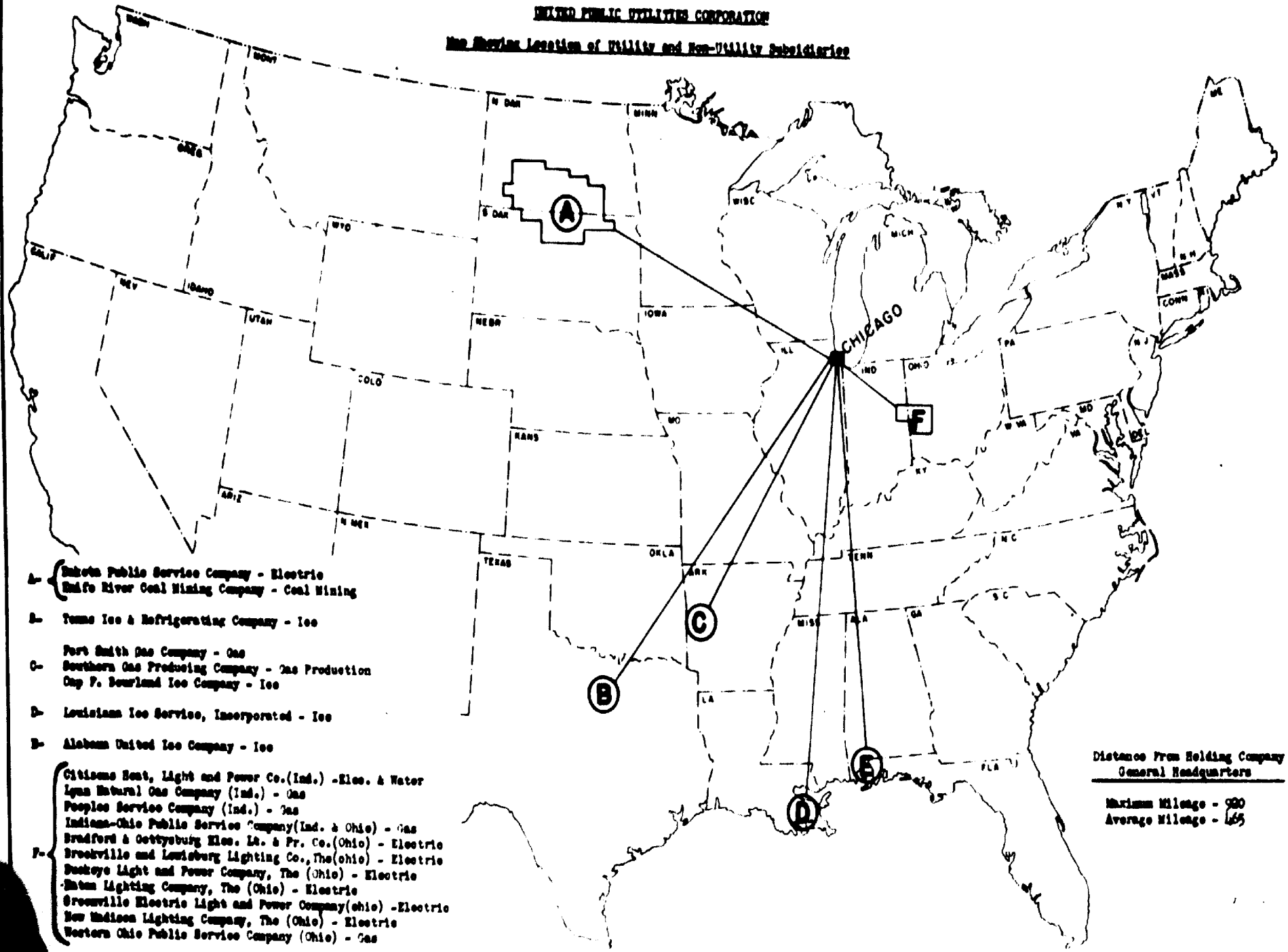
[1] Holding Company Act Release 3105.

[2] Ibid.

UNITED PUBLIC UTILITIES CORPORATION

Map Showing Location of Utility and Non-Utility Subsidiaries



A- Dakota Public Service Company - Electric
Knife River Coal Mining Company - Coal Mining

B- Texas Ice & Refrigerating Company - Ice

C- Fort Smith Gas Company - Gas
Southern Gas Producing Company - Gas Production
Clay F. Scurlock Ice Company - Ice

D- Louisiana Ice Service, Incorporated - Ice

E- Alabama United Ice Company - Ice

F- Citizens Heat, Light and Power Co.(Ind.) -Elec. & Water
Lynn Natural Gas Company (Ind.) - Gas
Peoples Service Company (Ind.) - Gas
Indiana-Ohio Public Service Company(Ind. & Ohio) - Gas
Bradford & Gettysburg Elec. Lt. & Pr. Co.(Ohio) - Electric
Brookville and Lewisburg Lighting Co., The(ohio) - Electric
Buckeye Light and Power Company, The (Ohio) - Electric
Eaton Lighting Company, The (Ohio) - Electric
Greenville Electric Light and Power Company(ohio) -Electric
New Madison Lighting Company, The (Ohio) - Electric
Western Ohio Public Service Company (Ohio) - Gas

Distance From Holding Company General Headquarters

Maximum Mileage - 980
Average Mileage - 665

> additional systems be proved wrong, we are making no proof regarding economies in the retention of those [southern companies].

On this basis, the Commission ordered the divestment of the southern (non-electric) companies from the system.[1] Further proceedings under clause (B) were deferred, evidently to await the results of court cases then in progress on the Commission's interpretation of this clause.[2] However, in 1945, before the Supreme Court decided this issue, United Public Utilities requested the Commission to approve of its plans to sell the Dakota properties.[3] On October 19, 1945, the Commission approved the sale.[4] The purchaser was Montana-Dakota Utilities Company, which was not a holding company nor a subsidiary or affiliate of a holding company or another public utility.

Dakota Public Service Company, the electric property being sold, served about 20 thousand customers in an area including Bismark, South Dakota, and Mandan and Dickson, North Dakota. Its service area was adjacent to that of Montana-Dakota, which served western North and South Dakota,

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[1] Holding Company Act Release 3368.

[2] See the North American Company case, above, p. 188.

[3] However, the single area interpretation of the Commission had been upheld by lower courts prior to this. See Engineers Public Service Company, above, p. 146.

[4] Holding Company Act Release 6142.

eastern Montana, and Canada. The properties were not interconnected, but Montana-Dakota proposed, upon acquiring Dakota Public Service, to construct two transmission lines interconnecting them in order to "permit interchange of power."

The acquisition by Montana-Dakota was subject to the approval of the Federal Power Commission and the North Dakota Public Service Commission. Both approved. The Securities and Exchange Commission noted that:

> While United Public Utilities has not been ordered to divest itself of its interest in Dakota or Knife River [Knife River was a coal company subsidiary which supplied fuel by conveyor to the steam generating plant of Dakota], it is obvious that the properties of Dakota and Knife River and the Indiana-Ohio group, located in states which do not adjoin each other, cannot be retained in combination under the standards of clause (B) of Section 11 (b) (1).

On the date of Commission approval of the sale, Dakota Public Service was merged into Montana-Dakota.

The dispositions of the remaining electric properties in Indiana and Ohio have already been discussed. American Gas and Electric acquired Citizen's Heat, Light and Power Company,[1] and the six Ohio electric companies were purchased by the Dayton Power and Light Company.[2] These divestments were made pursuant to a Section 11 (e) (voluntary) plan of dissolution, made necessary due to substantial dividend arrearages on its preferred stock.[3] United Public Utilities,

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[1] See above, pp. 112 ff.

[2] See above, pp. 207 ff.

[3] Holding Company Act Release 7984.

having no electric subsidiaries, disposed of its remaining properties and wound up its corporate affairs.

Analysis

The question of gains of economies of the Indiana and Ohio electric companies, all of which were acquired by holding company subsidiaries, has already been discussed in the analysis of the respective systems. The only question remaining here is the effect on Dakota Public Service Company of its separation from United Public Utilities.

The fact that hydro-power was to become available to Dakota when the interconnection between Montana-Dakota and it was completed, indicates the possibility of gains in plant economies over and above those usually considered in conjunction with the interconnection of operating units--i.e., reduction in necessary plant and lowest marginal cost production of additional necessary energy.[1] Thus, plant economies should have resulted from the interconnection, even though it is not known whether the two companies were so integrated as to have central load dispatching.

Using the same formula as before to measure changes in firm economies, in so far as they are measurable, the following table shows the results of the acquisition of Dakota by Montana-Dakota.

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[1] Montana-Dakota received energy from the U. S. Bureau of Reclamation's Fort Peck hydro-electric project.

TABLE 22

DAKOTA PUBLIC SERVICE AND MONTANA-DAKOTA UTILITIES
Administrative and General Expenses (Excluding the Pension Account) as a Percentage of Gross Electric Operating Revenues for the Combined Companies

Year	Per Cent
1939	7.3
1940	6.5
1941	6.5
1942	6.1
1943	5.8
1944	6.0
1945[a]	6.1
1946	4.6
1947[b]	4.5
1948	6.4
1949	4.2
1950	4.2

[a] Acquisition of Dakota Public Service Company, October 19, 1945.

[b] Acquisition of Sheridan County Electric Company, July 14, 1947 (until 1945, Sheridan had been a subsidiary of Cities Service).

The merger of the two companies, which were roughly of equal size, resulted in lower averages for both. The average for the combined companies, while Dakota was still a subsidiary of United Public Utilities, is 6.4 per cent, while the average for the combined companies after merger is 5.5 per cent.

There is no indication from the data of loss of firm economies due to separation here.

CHAPTER V

CONCLUSION

The preceding two chapters contain detailed studies of all the electric systems to which Section 11 (b) (1) has been applied.[1] This information, together with that contained in Chapter II, makes it possible to determine the general impact of that section on the costs of subsidiary companies. The effect on plant costs will be examined, and then the effect on firm costs.

Among the systems studied there are only two instances of Commission orders requiring the separation of interconnected electric properties. The North American Company was

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[1] There are two minor exceptions to this. Not included are Republic Electric Power Corporation and Utilities Stock and Bond Corporation. The first company owned three extremely small distribution companies on the West Coast. In 1938 the Commission held the "ABC" provisions were met. A voluntary plan called for eventual dissolution of Republic (Holding Company Act Release 1270). The second company met the requirements of the Act by distributing all of the stock it held (17 per cent) in its single electric subsidiary to its stockholders (Holding Company Act Release 3863). Section 11 (b) (1) proceedings against Central Public Utilities Corporation were postponed until 1946, in order that the company could divest its properties under a voluntary plan brought about because of near bankruptcy--the holding company's income bonds were in default (Holding Company Act Release 3225 and Moody's Manual, 1947). The electric subsidiaries consisted of seven small properties located in five states. Since the system was liquidated, the Act was never applied to it.

ordered to divest Illinois Iowa Power Company, which was interconnected with the Union Electric Company, North American's principal system. Commonwealth and Southern Corporation was required to dispose of South Carolina Power Company which was interconnected with Georgia Power Company, a part of Commonwealth and Southern's principal system (now the Southern Corporation).

As has been pointed out, the economic effects in these two instances, in terms of losses of plant economies, have been negligible.[1] In the first, North American had introduced no testimony or evidence that it was desirable for the two properties to be kept together. The Commission pointed out that the system could introduce evidence on this point if it desired, thus intimating that the Commission would consider reversing the decision for cause. Such evidence was never introduced and the system showed no desire to keep the two together. As far as can be determined, operating relationships between the two companies were not affected by the separation.

In the second, South Carolina Power purchased less than 5 per cent of its energy from Georgia Power while purchasing over 55 per cent from a state hydro-electric project. In addition, South Carolina Power was building a new steam generating plant, and it was testified that upon its completion

[1] See above, pp. 193 and 228-229.

even less energy would be purchased from Georgia Power. It is doubtful that there has been any loss of plant economies due to separation of these two companies, since there has been no physical separation.

With these exceptions, there is no evidence whatever that forced geographic integration has resulted in the loss of any plant economies. To be sure, there have been a number of cases where interconnected properties which were under divestiture orders were separated, but these were all management, rather than Commission, decisions. They could have remained together had management so desired. In some cases the Commission could have prevented separation,[1] but once the companies ceased to be holding company subsidiaries, the Commission was powerless to act.

Only in the case of Cities Service did the Commission refuse to allow the retention of properties which were claimed to be capable of physical interconnection with the principal system. Therefore, it appears that this was the only instance where the Commission's orders could have resulted in loss of future plant economies. Three claims of future economies made by Cities Service were rejected by the Commission.

In the first situation, it was claimed that plant economies would result if the St. Joseph property were

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[1] In the writer's opinion, it should have done so in at least one instance. See above, p. 60.

interconnected with system properties about 100 miles distant, which would allow the movement of power from the Joplin generating station, about 200 miles away. The St. Joseph company was later sold to the United Light and Railways system, which interconnected it with Kansas City Power and Light's large generators by building a 50-mile tie. Clearly, this latter interconnection was more economic than the former would have been.

In the second situation, which concerned the Tucson Gas, Electric Light and Power Company, it is clear that the 200-mile interconnection between it and Demming would not be built unless hydro-electric energy were to be made available by the United States Bureau of Reclamation. If it did become available, the Bureau would build the lines in order to sell the energy. Only by building system lines could these Cities Service properties develop a system flow of power, and the duplication of transmission lines would be clearly undesirable.[1] Thus, separation from the system could have no effect on the Tucson property's future plant costs.

There is the possibility of future increases in plant costs in the third situation. The Commission decided that the Trinidad Company could be a part of either of two systems. It could be retained with Public Service Company of Colorado,

[1] Even then, the amount of flow between generators 400 miles apart--Demming having only negligible capacity--would be minor, to say the least, because of line losses.

or, together with a portion of this latter company (the Salida-Alamosa division), it could be retained with the New Mexico Power Company, but the two groups could not be retained together. Cities Service had claimed such retention would result in future operating economies. Subsequent events appear to make the possibility of loss seem minimal, since neither Public Service of Colorado nor New Mexico Power Company made any attempt to acquire the Trinidad property, and it became an independent company.[1]

While losses of plant economies due to forced geographic integration have been negligible, gains in plant economies have been large. These gains have often been a sort of by-product of application of Section 11 (b) (1). Holding companies which have been ordered to divest properties which were not part of an operating unit have, in many cases, sold them to the economically logical operator. There are two obvious examples, both of which have resulted in eliminating duplicate urban facilities. The United Gas Improvement Company traded Erie County Electric Company to the

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[1] See above, pp. 93-94. The above statement is not entirely correct, since New Mexico's acquisition of Trinidad with or without Salida-Alamosa would have brought it under the jurisdiction of the Federal Power Commission, and possibly the Securities and Exchange Commission.

However, the main claim was that interconnections between the main body of Public Service and Salida-Alamosa, and Trinidad and Salida-Alamosa, were economically desirable. Public Service could have acquired the properties of Trinidad without coming under the jurisdiction of any Federal regulatory agency.

Associated Gas and Electric Company whose subsidiary, Pennsylvania Electric Company, was in direct competition with Erie County in the city of Erie, Pennsylvania. The merger of these two operating companies eliminated the duplication of service in this city.[1] In the other case, the Ogden Corporation, under a voluntary (Section 11 (e)) plan to meet the requirements of Section 11 (b) (1), sold Laclede Power and Light Company to Union Electric Company of Missouri, the principal system of the North American Company. The two operating companies had been in direct competition in the city of St. Louis, and the acquisition of course eliminated duplicating of facilities.

In general, the only cases involving gains in plant economies discussed herein have been interholding company transactions--that is, those over which the Commission has nad jurisdiction under Section 10 (c) (2)--and it is in these cases alone that data are available to indicate the magnitude of reductions in plant costs from re-grouping operating units. But the discussion in Chapter II of economies from increased plant size indicates the probability of plant economies from acquisition of subsidiaries by operating units not affiliated with a holding company system. There can be

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[1] United Gas received, in return, Eastern Shore Public Service Company, which it merged into the only operating company with which it could be interconnected. This acquisition resulted in a gain in economies. See above, pp. 264-267.

no doubt that the numerous acquisitions of adjacent companies have increased the average size of integrated plant, and thus unit costs must have declined. While these transfers which resulted in increasing plant size could have been accomplished without application of the Act, there is no reason to think that they would have been accomplished.

In addition, the requirements of the Act have apparently resulted in some slight reductions of plant costs through the operational integration of adjacent operating companies which had been subsidiaries of the same holding company. When a new holding company, Texas Utilities, was set up in the Electric Bond and Share system to take over three Texas subsidiaries, it was said that the result would be a higher degree of coordination in the operating of the three companies (which previously had coordinated their operations by contracts) and an increase in long-range group planning, which presumably should give rise to a reduction in necessary capacity.[1]

It appears safe to conclude that the net effect of forced geographic integration on plant costs has been to reduce

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[1] This may have been said simply to obtain the Commission's approval, but the Commission has apparently been wary of unsupported claims, and it did not object to this testimony.

There is another apparently similar example, that of Union Electric Company of Missouri's acquisition of Missouri Power and Light (see p. 190), but it is not clear here that economies over and above those obtained under holding company control would be gotten.

them. This has resulted even though, as pointed out in Chapter I, it was probably not an objective Congress had in mind when the Act was passed.

The question of whether costs which are a function of firm size, in contrast with plant size, have been increased due to forced geographic integration has no such clear-cut answer. Obviously, holding company size has been reduced, but operating company size has not. In Chapter II it was concluded that the most likely place for holding company size to affect firm costs was in the account "administrative and general expense." The same conclusion was reached by holding company systems when they attempted to meet the requirements of clause (A), since in practically every case in Chapter III it was claimed that it was in this account that the increased costs due to separation would occur. Estimates of the amount of cost increases ran as high as 15 per cent of electric operating revenues. On the average, the account itself was expected to increase on the order of magnitude of 20 to 50 per cent.

The difficulty of determining whether this has happened as a result of the divestment of subsidiaries is obvious. If the volume of business, both in real and in money terms, did not change, it would be a simple matter to measure changes in administrative and general expenses due to separation, since if economies were lost, the dollar amount of this account would rise. This is the technique by which

anticipated increases were measured in the cases under discussion, but it is only valid under the above assumption. Unfortunately, from this standpoint, the dollar volume of business, due both to physical and price-level increases, more than doubled over the period 1938-1950, the years for which data are available. This means that changes in the dollar amount of administrative and general expense include more than the effect of divestiture, and therefore, in order to isolate this, another technique must be used. The one followed is to find what percentage this account is of gross electric operating revenue for each year (1938-1950) for every divested subsidiary for which data are available.[1] These percentages are averaged for the years prior to separation, and for the years following. The percentage change between these two averages is then found. This figure is compared with the comparable one for all electric utilities.[2] While the comparison is probably of little significance for any one company, a general relative increase in this figure for all divested subsidiaries, as compared with all companies,

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[1] The pension account is deducted from administrative and general expense before the percentage is calculated in order to eliminate an increasing item which tends to obscure what is being sought. See Appendix for a complete explanation.

[2] The figures for all companies were obtained by summing all administrative and general expense accounts and dividing them by total electric revenues. This was done for each of the 13 years. Then the average of these for the years prior to, and after, a particular year were compared as above. See Appendix for these data.

would appear to indicate loss of firm economies. No loss would be indicated if there were no general increase in this figure.

While by no means a perfect measure, this seems the best that can be devised with available data. Administrative and general expense is such a small percentage of revenues that if it is doubled, and revenues increase sufficiently to cover the increase in costs, the account, as a percentage of revenues, will still be approximately twice as large as previously.[1] The use of averages eliminates revenue or administrative and general expense changes that are peculiar to one company.[2] The averaging should thus eliminate nearly all extraneous changes and it should be possible to determine whether firm economies have been lost.

Table 23 summarizes the data developed in Chapters III and IV.

In addition, the four divested companies (for which data are available) which were acquired by an independent

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[1] If administrative and general expenses are 5 per cent of revenues (an average figure) and this account doubles, with revenues increasing by the same amount, the account will be more than 9.5 per cent of revenues.

[2] It also tends to eliminate differences caused by different time lags in rate increases as inflation forces up dollar costs. This problem exists because of the large number of regulatory agencies. There is no apparent bias in the data due to concentration in a particular state of companies in either sample. Nor is there an apparent bias in size of companies in one sample compared with the other.

TABLE 23

EFFECT OF DIVESTITURE ON ADMINISTRATIVE AND GENERAL EXPENSE

Year	Number of Companies Divested	Change in Relative Magnitude after Divestiture--by Companies Per Cent	Decline in National Average Per Cent	Divested Companies in Relation to the National Average		
				Declined More than National Average	Declined Equal to National Average (+ or -1 Per Cent)	Declined Less than National Average
1941	3	-18 -17 -3	-16	1	1	1
1942	0					
1943	6	-27 -16 -12 -11 -3 +6	-11	2	2	2
1944	8	-34 -25 -25 -16 -11 -9 -4 -3	-9	5	1	2
1945	11	-60 -48 -32 27 -23 14 -12 -11 -5 +2 +4	-8	8	0	3
1946	9	-24 -20 -19 -13 -11 -6 -5 +2 +5	-10	4	1	4
1947	8	-35 -18 -8 +6 +12 +13 +13 +15	-8	2	1	5
1948	6	-38 -28 -19 -17 -12 -8	-8	5	1	0
1949	10	-27 -24 -23 -20 -7 -5 +5 +6 +12 +19	-8	4	1	5
	61			31	8	22

company all show declines greater than the national average. In the case of the four holding company groups which became independent (American Gas and Electric, Central and Southwest, Middle South Utilities and the Southern Corporation), considered as systems, one shows a decline greater than the national average, one shows the same decline, and two show declines less than the national average.

Although the evidence does not necessarily prove the point, there is nothing in the data to indicate a general increase in administrative and general expenses due to separation from a holding company system. It does not follow that these former subsidiaries might not have become better off, in terms of this account, had they remained in a holding company system. The indications are that they did not become worse off, compared to operating companies in general. That this should be true is not surprising when it is realized that the bulk of the former subsidiaries still use the services of the same service companies that they did as subsidiaries--although both are now independent--on about the same basis as before.[1] The doubling in revenues of the average company over the period has no doubt made it possible for many operating companies to perform certain management functions which might have been uneconomical for them when they were smaller.

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[1] That is, charges in general are on a cost plus basis, as they have been since the Commission began to regulate service companies, which was prior to 1938.

Conclusions regarding capital costs are similar. About as many systems expected lower as higher costs in obtaining capital. In light of studies reviewed in Chapter II and of evidence contained in Chapters III and IV, general losses in this firm cost cannot be anticipated, especially since there is no reason to believe that holding companies have done much financing for subsidiaries.

Thus, general increases in firm costs appear to be nonexistent, or, at most, negligible. Since reductions in plant costs have been realized, the conclusion must be that the Commission's application of the forced geographic integration provisions of the Act has not resulted in increased costs.

It of course does not follow that this country has achieved the lowest possible cost of electricity as it depends on company and geographic organization. This was not the objective of the Act, and it was not the goal of the Commission in applying it. Therefore, even though forced geographic integration may well have been a step in the right direction (this is certainly true in so far as plant size is concerned), it is unlikely that this result has been attained.[1]

[1] See Emery Troxell, "Holding Company Integration: Several Comments," Land Economics, 24 (February, 1948), 86-89. For a vigorous statement concerning the lack of a rational electric system, see Horace H. Gray, "The Integration of the Electric Power Industry," American Economic Review, Papers and Proceedings, Vol. XLI, No. 2 (May, 1951), pp. 538-549. But see also the rejoinder made by David G. Tyndall, loc. cit., pp. 550-552.

Indeed, at least one case discussed herein demonstrates this. The Commission's decision to disapprove American Gas and Electric's acquisition of Columbus and Southern Ohio prevented considerable cost reductions.[1] While perhaps proper, in view of the disparate requirements of the Act, the decision appears to have been unfortunate from a purely economic standpoint.

However, some steps have been taken to achieve the most economic size of system, and there is reason to believe that more will be done in the near future. Apart from the results already discussed, the Federal Power Commission is empowered to "divide the country into regional districts for the voluntary [emphasis supplied] interconnection and coordination of facilities for the generation, transmission and sale of electric energy." The Power Commission may require physical interconnection only when requested by a state commission or electric company, and provided such interconnection will not result in impairment of service to the company's own customers and does not necessitate increased capacity.[3] The Power Commission is also empowered to require interconnections necessary for national defense during an emergency,

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[1] See above, pp. 106-110.

[2] Section 202 of the Federal Power Act of 1935.

[3] Ibid. The author can find no record of this mandatory provision ever having been used.

and many such connections were ordered during the war. Few remained in existence after the War, in part at least, because the companies involved thus escaped federal regulation.[1]

While this Commission has never officially published the results of its studies of optimal operating areas, it did tentatively divide the country in 1936 into 48 "power districts," which were grouped into 8 "power regions." The districts were outlined so that each would embrace an area which, in the judgment of the Commission, could be served economically as an integrated operating unit. These divisions were discussed with state commissions and utility officials. The boundaries have been changed from time to time since 1936 to account for interconnections, mergers and other changes. One purpose of these divisions was to afford a proper and convenient basis upon which the necessary data could be assembled to determine the economic boundaries for regional integration.[2] While the boundaries of these power supply areas are generally available, the data which determine them are not.

The Power Commission encourages the voluntary interconnection of electric companies by making engineering studies of potential interconnections and transmitting this information to "interested Federal agencies, State officials, and

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[1] Gray, "The Integration of the Electric Power Industry," op. cit., p. 545.

[2] This information was furnished by Nelson Lee Smith, Commissioner of the Federal Power Commission.

electric utilities."[1] This information is not made generally available.

The Securities and Exchange Commission is about to undertake work in this area also. Section 30 of the Public Utility Holding Company Act requires the Commission to recommend, in public reports, the "type and size of geographically and economically integrated .... systems which .... can best promote and harmonize the interests of the public, the investors and the consumer." Section 30 has been neglected since 1935, since the Commission felt that application of Section 11 (b) (1) had priority. However, a recent speech by Donald Cook, chairman of the Securities and Exchange Commission, indicates that, since this has been almost completely accomplished, studies under Section 30 are about to begin.[2] The intent, of course, will be to determine economically desirable interconnections and integrations of adjacent operating companies.[3] The Commission is not empowered to require

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[1] Federal Power Commission, 31st Annual Report (1951), p. 62. In fiscal 1951, for example, 4 such studies were completed, 7 were in progress, and 3 were terminated "due either to the demonstration of insufficient economic benefit or to the construction of facilities serving purposes similar to the proposed connections." Ibid.

[2] Donald C. Cook, "Public Utility System Integration--A Study for Future Progress." Address before the Public Utility Executive Program, University of Michigan School of Business Administration, Ann Arbor, July 17, 1952. Mimeographed.

[3] This is essentially the purpose of Section 202 of the Federal Power Act. The reason Congress provided for this apparent duplication is not clear.

such interconnection; however, Chairman Cook stated the Commission felt that,

> for the most part any recommendations made under Section 30 would be adopted voluntarily by the companies or systems concerned. If the recommendations are based on facts, add up to good sense, have the support of other regulatory bodies, and are in the public interest, it should be possible around the conference table to persuade the systems affected to cooperate. This is particularly the case since as I see it a large proportion of our recommendations would be advantageous to all concerned.

Commissioner Cook expressed the belief that, by working in conjunction with the Federal Power Commission, certain recommendations could be made mandatory under Section 202 of the Federal Power Act.

While the results of these studies by the two commissions are far from clear, it appears that if they take into account all relevant costs and are made generally available, it will be possible at last to reach concrete conclusions as to whether voluntary action has resulted in minimum electric costs, or whether (and what kind of) compulsory legislation is necessary to attain this goal.

APPENDIX

As noted in Chapter II, a means of measuring (some) firm costs is through the use of the Federal Power Commission's account, "administrative and general expenses." This account is available for all class A and B privately owned electric utility companies in the U. S., since they report to the Federal Power Commission their operating expenses (among other things) on a uniform basis.[1]

There are six general sub-headings under expenses: production expenses, transmission expenses, distributing expenses, customer accounting and collecting expenses, sales promotion expenses, and administrative and general expenses. This information is published annually by the FPC in a series entitled Statistics of Electric Utilities in the United States, Washington, 1938--. The administration and general expenses account now contains the following sub-accounts:

Line #119	Salaries of general officers and executives
120	Other general office salaries
121	Expenses of general officers
122	Expenses of general office employees
123	General office supplies and expenses

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[1] Classes A and B include, generally, those companies which have annual electric revenues of more than $250,000.

[2] Prior to 1948 the account was broken down in less detail. In some cases two or more of the present items were lumped under a more general heading. However, the same items were included. See Statistics, 1948, pp. v and xvi.

124 Management and supervision fees and expenses
125 Special services
126 Legal services
127 Regulatory commission expenses
128 Insurance
129 Injuries and damages
130 Employees' welfare expenses
131 Pensions
132 Miscellaneous general expenses
133 Maintenance of general property
134 Rents
135 Commissions paid under agency sales contracts
136 Franchise requirements
137 Duplicate miscellaneous charges--Credit
138 Administrative and general expenses transferred--Credit
139 Joint expenses--Debit
140 Joint expenses--Credit

It seems desirable to eliminate some of the items from the account in order to be sure that the right thing is being measured. The items in lines 119 through 125 certainly are management costs, and should thus be included. Items number 126 through 130 vary, of course, from year to year in response to other factors, but these are the sort of advisory services often provided by service companies to subsidiaries, and so probably should be included, with the hope that the fluctuations will average out, more or less. Not much can be said about what should be done with the miscellaneous, duplicate and joint items, lines 132 and 137-140. Probably most of them should be kept in the account. Lines 133-136 probably should not be included, but they are so small in magnitude (line 135 is commonly zero) and so proportionate over the period that including them does not change the accounts significantly. Lines 130 and 131, the total of which is called

the pension account, give the most trouble. It has, in all cases included in this paper, become a larger part of the total over the period.[1] This is undoubtedly due to increased pension provisions in labor contracts, which have come into widespread use in the past five to ten years, although some of it is no doubt management cost.

It is not at all apparent that the size of the pension account,[2] that is, lines 130 and 131, is a function of firm size, except in so far as larger firm size can reduce the cost of servicing a given pension plan. It seems improbable that the size of firm has any connection with the size of the pension plan itself. Therefore, the pension account (lines 130 and 131) has been eliminated from administrative and general expenses, since that total appears to be the significant one.

Changes in the absolute dollar amount of administrative and general expenses would be a real measure of (at least part of) changes in firm costs due to separation from a holding company, only if nothing else changed; that is, the volume of business, both in real and money terms, remained

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[1] To cite one example, that of Cincinnati Gas and Electric Company (see Columbia Gas and Electric Company, above, pp. 202 ff), the pension account was 13 per cent of the total administrative and general expenses in 1938 and 48 per cent in 1950.

[2] The sum of the two lines is used as the pension account, because prior to 1948, the sum of the two was not broken down, and since 1948 it has not been broken down by all companies.

the same, and the size of the operating utility itself remained the same. This, of course, is not even approximately true for the period under discussion.[1] Therefore, a technique had to be devised to attempt to measure relative changes. The one followed is to calculate administrative and general expenses as a percentage of gross electric operating revenue, to average these percentages both for the years prior to, and after, separation, and to compare the two averages. This comparison for any one company is probably not very meaningful, since if costs go up in the electric industry, rates will follow sooner or later. Also, the percentage would change if revenues changed, due to either rate or volume changes. However, any loss of firm economies due to separation from holding company systems should be unusual--that is, over and above any changes which would occur due to changing conditions if the company remained in the system. If the above percentages are known for the total of all companies in the United States for every year, a comparison of the changes in the averages of the percentages before and after separation for the particular company under study, compared to the change in the averages of percentages of all companies for the same two periods, should indicate if there were any unusual changes. If this is done for a large number of affected

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[1] Gross electric operating revenues of privately owned companies totaled about $2,169,000,000 in 1938 and $4,382,000,000 in 1950.

companies, general losses of firm economies in the involved category should show up. That is, the average of the percentages after separation should be higher, compared to the same average for the years before separation, for the former subsidiaries than for all electric companies. If this is not generally true, then it would appear that these firm costs are not increased upon separation from holding companies.

The data for all companies, with which individual company data is compared in Chapters III and IV, is shown in the following table:

TABLE 24

ALL CLASS A AND B PRIVATELY OWNED ELECTRIC UTILITIES IN THE UNITED STATES
Administrative and General Expenses (Less the Pension Account) as a Percentage of Gross Electric Operating Revenues

Year	Per Cent	Year	Per Cent
1938	6.0	1945	4.8
1939	5.7	1946	4.9
1940	5.4	1947	4.9
1941	4.9	1948	4.6
1942	4.9	1949	4.7
1943	5.0	1950	4.7
1944	4.7		

Year	Averages of Above Per Cents for Years Prior to that Year	Averages of Above Per Cents for Years Following that Year	Per Cent Decline of Column 2 from Column 1
1941	5.7	4.8	16
1942	5.4	4.8	11
1943	5.4	4.8	11
1944	5.3	4.8	9
1945	5.2	4.8	8
1946	5.2	4.7	10
1947	5.1	4.7	8
1948	5.1	4.7	8
1949	5.1	4.7	8

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