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Opportunities to develop a strategic competitive advantage in the electric utility industry

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OPPORTUNITIES TO DEVELOP A STRATEGIC COMPETITIVE ADVANTAGE IN THE ELECTRIC UTILITY INDUSTRY

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Abstract

OPPORTUNITIES TO DEVELOP A STRATEGIC COMPETITIVE ADVANTAGE IN THE ELECTRIC UTILITY INDUSTRY

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Competitive forces are gaining more steam within an industry that has been characterized as a regulated monopoly. Electric Utilities must develop a strategic competitive advantage in order to survive and succeed in this new environment. This project articulates the more significant competitive issues impacting the generation, transmission and distribution of electric power. Issues are organized and focused, communicating the important connection between the macroenvironment and successful strategy development. The project explores several parameters which could provide an indication of the relative strengths or weaknesses of market participants. Specific utilities are evaluated to reveal the opportunities and challenges facing executive management. The project concludes that there are several accessible indicators of a utility's need to develop and implement competitive strategies. A number of activities are proposed to identify and validate important parameters; define the real needs of investor-owned utilities; construct effective issue identification programs; and develop strategies which enhance the corporation's ability to succeed in an increasingly competitive market.

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CHAPTER 1

Project Scope & Objectives

Competition...Electric Utilities - a concept, and an industry, that until recently, represented opposite ends of the U. S. business and economic spectrum. Today, market forces are steadily replacing rate-of-return regulation.

Traditional electric utilities face profound challenges as they move from a regulated monopoly toward a competitive market structure. The energy crisis and the multi-billion dollar nuclear construction debacle, of the 1970s and early 1980s, have contributed to the intense pressures for discipline through pricing and cost control. The Public Utilities Regulatory Power Act of 1978 (PURPA) represented the initial legislative response to these pressures. PURPA created a market for power generated by non-utilities. The result was a hugh influx of cogenerators and other Qualifying Facilities (QFs) into the power generation market. By 1986 cogenerators represented more than 3 percent of the total U.S. power generation. In 1988, the Federal Energy Regulatory Commission (FERC) issued three Notices of Public Rulemaking (NOPRs) which further stimulated competitive forces. The NOPRs provided guidance concerning the pricing of cogenerated power, competitive bidding for new generation and perhaps most importantly, relaxed regulation for an administratively new class of electric power generators called Independent Power Producers or IPPs.

As we move into the 1990s, the continuing growth of the United States economy has contributed to a significant increase in the forecasted demand for electrical power. While demand is increasing, the power supply is dwindling. Utilities are reluctant to build new capacity due to the disincentives of high construction costs and regulatory red tape. 65 nuclear reactors have been canceled since the Three Mile Island accident. Clean air legislation threatens to shut down coal-fired power plants that do not comply with emissions standards.

In this climate of increasingly competitive industrial and commercial markets and imbalanced supply-demand relationships, IPPs and cogenerators, collectively referred to as non-utility generators (NUGs), have been extremely successful at implementing profitable power generation projects. Manufacturers and bulk power users have contracted directly with NUGs for less expensive power, bypassing the franchise utility and consequently reducing that utility's customer base. Some public utilities have reacted to the NUG's success by restructuring their strategies to accommodate the market dynamics of the 90s. These utilities have contracted with NUGs to supply a portion of the power needs within their regulated service territory. Other utilities are creating non-regulated subsidiaries which will build and operate independent power projects outside their franchise area, thus threatening the customer base of the indigenous regulated·

utility.

Non-utility generators have achieved a critical mass that portends a need for investor-owned electric utilities to consider vastly different business strategies. This project will take the first steps toward understanding the competitive market dynamics and articulating the impact of these forces on the industry in general and on specific electric utilities.

Chapter 2 of this project, discusses the general philosophy that motivated the study and the methodology used to define the competitive issues, select specific utilities for evaluation, and prepare the case analyses for each of the selected utilities.

Chapter 3 describes the specific issues impacting the generation, transmission and distribution of electric power. This section is generally derived from the existing literature. The chronological presentation is intended to provide the reader with a feel for the influence of the macroenvironment. Chapter 3 concentrates on the forces which, in retrospect, have been the most significant. Clearly, an ability to distinguish the most significant current and future issues must create an advantage for those who are able to implement strategies which anticipate change.

Chapters 4 through 6 present operational and comparative data for each selected utility, together with a case analysis. Each case analysis will discuss the perceived success or failure of current business strategies and considerations which, if implemented, could potentially improve the utility's competitive advantage.

Chapter 7 summarizes the findings of this project. Chapter 7 also describes the continuing research and development required to move beyond academic analysis into practical strategic policy formulation for the electric utility industry.

CHAPTER 2

Methodology

PROJECT PHILOSOPHY

Investor-owned public utilities are operating in an increasingly competitive market. The managers of these organizations can no longer assume their utilities will continue to operate as regulated monopolies. Management must, instead, look beyond traditional methods of operation and develop strategies which will position the utility to take advantage of opportunities and defend against threats.

This project is motivated by the assumption that there are tremendous opportunities to assist utility management in developing competitive strategies. The project is designed to provide basic information concerning the nature of the industry and the impact of competitive forces. This information should be used as a foundation for marketing programs and value-added products and services that address various elements of competitive strategy formulation for the electric utility industry.

APPROACH

1. Issue definitions were developed from hundreds of data sources which have been collected during the past two years. These sources include: industry projects and reports such as those produced by Electric Power Research Institute (EPRI), Edison Electric Institute (EEI) and The North American Electric Reliability Council (NERC); articles published in industry journals, such as Electric Perspectives, Public Utilities Fortnightly, Power Engineering, Nuclear Industry, Electrical World etc. (several articles documented interviews with a number of utility executives); articles published in the business press such as The Wall Street Journal, Forbes, Barrons, etc.; and articles published in other journals, magazines and newspapers such as Cost Engineering, The New York Times, Engineering News Record, etc.

2. Initial utility data was derived from the "Compact Disclosure" data-base resident at the Morris Library, University of Delaware. The Standard Industrial Classification Manual was used to identify the primary "Standard Industrial Classification" (SIC) for electric and gas utilities. The following SIC codes were identified:

4911	Generation, Transmission and Distribution of Electrical Energy for Sale
4922	Natural Gas Transmission or Storage
4923	Natural Gas Transmission and Distribution
4924	Natural Gas Distribution

Investor-owned public utilities with primary or secondary SIC codes matching those above, and with corporate addresses in states east of the Mississippi were selected from the Compact Disclosure data-base.

The Compact Disclosure data-base contains much of the financial information associated with each corporation. This information is generally derived from the company's annual reports and 10K reports. The information selected for this project included the following for each utility:

NAME, ADDRESS, PHONE NUMBER

DESCRIPTION OF BUSINESS

NUMBER OF EMPLOYEES

SEGMENT DATA, INCLUDING SALES AND INCOME

FIVE YEAR SALES, NET INCOME AND EPS

ANNUAL ASSETS FOR YEARS 1986, 1987, 1988

ANNUAL LIABILITIES FOR YEARS 1986, 1987, 1988

ANNUAL INCOME FOR YEARS 1986, 1987, 1988

CASH FLOW PROVIDED FROM OPERATING ACTIVITY, 1986-1988

CASH FLOW PROVIDED FROM INVESTING ACTIVITY, 1986-1988

STOCK VOLUME, HIGH, LOW, CLOSE AND MARKET VALUE, 1988

EARNINGS INFORMATION

DIVIDEND INFORMATION

KEY ANNUAL FINANCIAL RATIOS FOR YEARS 1986, 1987, 1988

SUBSIDIARIES

Note: Generally no attempt was made to segregate subsidiaries from holding or parent companies.

3. Each utility was contacted, by phone, to request a copy of their latest Annual Report. Those utilities which did not respond were not included in the analysis. 82 utilities and subsidiaries were chosen for evaluation. Table 2.1 presents the

complete list together with the parameter information described below.

4. The following parameters were identified as important in determining the competitive health of each utility:

   - AVERAGE ANNUAL PERCENT CHANGE IN KILOWATT-HOUR SALES, 1986 - 1988

     This information was taken directly from the company's 1988 Annual Report.

   - AVERAGE ANNUAL PERCENT CHANGE IN TOTAL REVENUE, 1986 - 1988

   - AVERAGE ANNUAL PERCENT CHANGE IN NET INCOME, 1986 - 1988

   - AVERAGE ANNUAL COST OF GOODS SOLD AS A PERCENT OF SALES, 1986-1988

     Revenue, Net Income and Cost of Goods information was taken directly from the Compact Disclosure reports. Cost of Goods was calculated from the given COGs dollar amount divided by the given total revenue amount. Several COGs figures were checked against the company's annual report and were found to be accurate.

o DIFFERENCE BETWEEN THE AVERAGE ANNUAL KWH SALES GROWTH FOR THE UTILITY VERSUS THE OVERALL GROWTH IN KWH SALES FOR THE REGION, 1986-1987

Regional sales growth was derived from the "Statistical Yearbook of the Electric Utility Industry / 1988", published November 1989. Statistical Yearbook regions are designated by state and in some cases did not match exactly with each utility's service area. Where the utility's service area covered more than one region, the region which accounted for the greatest portion of the utility's service area was designated as the calculation region.

Although there is a difference between the growth periods, the project author felt the regional growth statistics provided an adequate comparison because they are much less susceptible to erratic behavior.

The analytical methodology could be improved by using more closely matched data for both regional and period growth comparisons.

5. The difference between the utility and regional Kwh sales growth, percent change in total revenue, and cost of goods sold (as a percent of sales) were chosen as the most critical parameters. Each utility was ranked from 1 to 82 based on its relative performance with regard to each of these critical parameters, 1 being the worst performance and 82 being the best performance. The relative rankings were added together for each utility to calculate an overall utility rank.

6. One utility was selected from each of three NERC regions based on their relatively poor overall performance rank i.e. the worst performers from each of the three regions were chosen for a detailed analysis. The following utilities were selected (the overall performance rank is listed next to each utility):

AMERICAN ELECTRIC POWER COMPANY, INC.	3
BOSTON EDISON	6
CENTRAL ILLINOIS PUBLIC SERVICE COMPANY	10

7. Operating and comparative data was derived for each of the selected utilities from the company's annual report, and the annual reports of the other utilities operating in the same NERC region. Other publications were used as footnoted.

8. Each case analysis attempts to summarize strategic problems and opportunities relative to the specific competitive environment. The case analyses are intended to provide possible strategic direction based on the available data. Additional data, including interviews with utility managers should improve the content and usefulness of these analyses.

TABLE 2.1 : UTILITY STATISTICS & DECISION MATRIX

PERIOD 1986 TO 1988

#	COMPANY NAME	% CHG KWH SALES	% CHG KWH REV.	% CHG NET INCOME	COGS / SALES	DELTA REG. VS. CO KWH	STATE REGION	NERC REGION	D	S	G	T
1	APPALACHIAN POWER CO.	-1.4	-1.1	-0.8	0.543	-5.3	3	1	3	13	25	41
2	FLORIDA PUBLIC UTILITIES	3.7	-1.7	-4.9	0.773	-0.9	5	7	29	10	2	41
3	AMERICAN ELECTRIC POWER CO. INC	-0.8	-0.7	5.1	0.564	-4.7	3	1	4	18	21	43
4	KENTUCKY POWER CO.	-0.5	0.1	1.9	0.620	-3.2	6	1	9	24	10	43
5	NEW ORLEANS PUBLIC SERVICE, INC		0.2	0.4	0.710	-2.7	6	8	15	26	3	44
6	BOSTON EDISON CO.	2.8	-1.1	-2.0	0.597	-2.4	1	6	20	14	13	47
7	MIDDLE SOUTH UTILITIES, INC.		-3.9	-4.1	0.495	-2.7	6	8	14	2	34	50
8	MISSISSIPPI POWER CO.	-0.6	-1.1	2.2	0.495	-3.3	6	7	8	15	35	58
9	UPPER PENINSULA POWER CO	2.3	0.7	8.3	0.692	-1.6	3	4	32	35	4	71
10	CENTRAL ILLINOIS PUBLIC SERVICE CO	-0.4	-3.1	-1.6	0.403	-4.3	3	4	5	4	65	74
11	NORTHERN STATES POWER CO.		4.2	17.2	0.642	-3.9	3	4	7	60	8	75
12	ARKANSAS POWER & LIGHT	-0.2	0.7	-1.7	0.604	-0.2	7	8	34	33	12	79
13	GEORGIA POWER CO.	1.9	3.8	2.9	0.630	-2.7	5	7	18	56	9	83
14	OHIO POWER CO.	1.1	-1.8	2.4	0.409	-2.8	3	1	12	9	62	83
15	NORTHERN INDIANA PUBLIC SERVICE CO.	7.0	-5.2	0.4	0.582	3.1	3	1	66	1	17	84
16	INDIANA MICHIGAN POWER CO.	-5.3	0.0	1.3	0.410	-9.2	3	1	1	23	61	85
17	P S I HOLDINGS INC.	4.2	-0.3	40.0	0.545	0.3	3	1	40	21	24	85
18	C M S ENERGY	4.3	-1.8	22.1	0.493	0.4	3	1	42	8	36	86
19	SCANA CORP.	2.7	-0.8	-0.1	0.443	-1.9	5	7	24	17	50	91
20	ORANGE & ROCKLAND UTILITIES INC.	4.1	-1.9	1.4	0.436	0.2	2	6	38	7	51	96
21	CENTRAL MAINE POWER CO.	5.0	1.6	-2.1	0.571	-0.2	1	6	33	44	20	97
22	ALABAMA POWER CO.	2.1	2.5	3.0	0.575	-0.6	6	7	31	49	19	99
23	EASTERN UTILITIES ASSOCIATES	4.6	0.6	4.5	0.489	-0.6	1	6	30	32	38	100
24	SOUTHERN CO.	2.0	2.8	2.8	0.514	-2.6	5	7	19	51	30	100
25	LOUISIANA POWER & LIGHT CO.		2.0	-10.7	0.476	-2.7	6	8	13	46	42	101
26	ILLINOIS POWER CO.	1.6	0.0	-11.8	0.410	-2.3	3	4	21	22	60	103
27	BANGOR HYDRO ELECTRICCO.	4.3	3.6	-9.4	0.554	-0.9	1	6	28	54	22	104
28	WISCONSIN PUBLIC SERVICE CORP.	6.9	-1.2	0.0	0.526	3.0	3	4	65	12	28	105
29	CINCINNATI GAS & ELECTRIC CO.	4.6	-0.4	11.9	0.480	0.7	3	1	45	20	41	106
30	NIAGARA MOHAWK POWER CORP.	0.9	0.9	-15.5	0.423	-3.0	2	6	11	38	57	106

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31	MISSISSIPPI POWER & LIGHT CO.	-2.9	5.1	1.8	0.489	-5.6	6	7	2	66	39	107
32	CENTRAL HUDSON GAS & ELECTRIC CORP.	5.3	-3.4	-3.0	0.430	1.4	2	6	53	3	52	108
33	SYSTEM ENERGY RESOURCES INC.		-1.4	-0.8	0.211	-2.7	6	7	17	11	82	110
34	PUBLIC SERVICE ENTERPRISE GROUP INC.	4.7	0.8	4.3	0.535	0.8	2	3	48	36	27	111
35	COMMONWEALTH ENERGY SYSTEM	20.5	-0.9	-4.9	0.595	15.3	1	6	81	16	15	112
36	W P L HOLDINGS INC.	2.9	0.8	1.5	0.454	-1.0	3	4	274	37	48	112
37	NECO ENTERPRISES INC.	5.5	8.2	-2.0	0.806	0.3	1	6	39	80	1	120
38	UNITED ILLUMINATING	3.8	0.3	2.8	0.368	-1.4	1	6	25	29	66	120
39	CILCORP INC.	5.5	-3.0	3.2	0.405	1.6	3	4	55	5	63	123
40	CAROLINA POWER & LIGHT CO.	4.5	4.1	-8.4	0.513	-0.1	5	7	36	58	31	125
41	NEW ENGLAND ELECTRIC SYSTEM	5.8	0.4	-151.9	0.429	0.6	1	6	44	31	53	128
42	GULF POWER CO.	5.3	1.3	1.9	0.482	0.7	5	7	47	42	40	129
43	BALTIMORE GAS & ELECTRIC CO.	2.6	1.0	4.4	0.363	-2.0	5	3	23	39	68	130
44	TECO ENERGY INC.	4.9	6.8	3.2	0.586	0.3	5	7	41	73	16	130
45	NEW YORK STATE ELECTRIC & GAS CORP.	4.2	3.4	-4.0	0.504	0.3	2	6	46	53	32	131
46	D P L INC.	8.1	-0.5	7.9	0.471	4.2	3	1	69	19	44	132
47	DUQUESNE LIGHT CO.		3.4	5.6	0.325	-3.9	2	3	6	52	74	132
48	CONSOLIDATED EDISON CO.	5.8	-2.2	-5.6	0.362	1.9	2	6	59	6	69	134
49	CENTERIOR ENERGY CORP.	0.8	14.0	-2.3	0.475	-3.1	3	1	10	82	43	135
50	UNITIL CORP.	7.2	6.4	5.9	0.657	2.0	1	6	60	72	5	137
51	MADISON GAS & ELECTRIC CO.	6.2	0.4	0.1	0.457	2.3	3	4	63	30	47	140
52	ROCHESTER GAS & ELECTRIC CORP.	4.7	0.1	-5.9	0.364	0.8	2	6	49	25	67	141
53	DOMINION RESOURCES INC.	5.1	4.7	6.9	0.493	0.5	5	7	43	63	37	143
54	FLORIDA PROGRESS CORP.	6.2	7.4	2.2	0.615	1.6	5	7	56	76	11	143
55	MONONGAMELA POWER CO.	16.3	4.7	3.0	0.652	11.7	5	1	78	64	6	148
56	DELMARVA POWER & LIGHT CO.	5.4	1.8	-1.8	0.429	0.8	5	3	50	45	54	149
57	GREEN MOUNTAIN POWER CO.	10.3	6.2	7.0	0.650	5.1	1	6	71	71	7	149
58	NORTHEAST UTILITIES	4.2	2.1	-4.0	0.301	-1.0	1	6	26	47	76	149
59	MAINE PUBLIC SERVICE CO.	3.1	9.6	0.3	0.445	-2.1	1	6	22	81	49	152

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60	DETROIT EDISON CO.	3.8	3.9	-167.2	0.404	-0.1	3	1	35	57	64	156
61	WEST PENN POWER CO.	15.4	4.4	1.0	0.575	11.5	2	3	77	61	18	156
62	KENTUCKY UTILITIES CO.	9.9	1.0	3.0	0.470	7.2	6	1	73	41	45	159
63	DUKE POWER CO.	4.6	6.0	-35.7	0.426	0.0	5	7	37	70	56	163
64	GENERAL PUBLIC UTILITIES	5.2	0.7	15.5	0.293	1.3	2	3	52	34	78	164
65	POTOMAC EDISON	20.5	5.8	4.3	0.595	15.9	5	3	82	69	14	165
66	SAVANNAH ELECTRIC & POWER CO.	5.4	3.6	9.3	0.419	0.8	5	7	51	55	59	165
67	OGLETHORPE POWER CO.	8.2	7.7	8.3	0.553	3.6	5	7	67	77	23	167
68	ALLEGHENY POWER SYSTEM INC.	17.1	4.7	3.0	0.541	13.2	3	1	80	62	26	168
69	METROPOLITAN EDISON CO.	6.1	0.3	15.6	0.249	2.2	2	3	61	28	80	169
70	CENTRAL VERMONT PUBLIC SERVICE CORP.	9.6	7.0	-2.3	0.515	4.4	1	6	70	74	29	173
71	WISCONSIN ENERGY CORP.	12.6	1.4	4.1	0.427	8.7	3	4	76	43	55	174
72	JERSEY CENTRAL POWER & LIGHT CO.	6.5	1.0	15.6	0.340	2.6	2	3	64	40	71	175
73	PHILADELPHIA ELECTRIC CO.	5.6	2.1	2.8	0.340	1.7	2	3	57	48	72	177
74	SOUTHERN INDIANA GAS & ELECTRIC	10.7	7.9	3.0	0.502	6.8	3	1	72	78	33	183
75	COMMONWEALTH EDISON CO.	5.7	2.6	-3.3	0.290	1.8	3	4	58	50	79	187
76	ATLANTIC ENERGY INC.	6.2	4.2	5.0	0.306	2.3	2	3	62	59	75	196
77	PENNSYLVANIA POWER CO.	12.1	4.9	-3.5	0.420	8.2	2	3	74	65	58	197
78	F L P GROUP INC.	16.6	8.2	8.1	0.469	12.0	5	7	79	79	46	204
79	PENNSYLVANIA POWER & LIGHT CO.	5.3	7.1	0.8	0.294	1.4	2	3	54	75	77	206
80	IPALCO ENTERPRISES INC.	7.6	5.8	6.1	0.330	3.7	3	1	68	68	73	209
81	OHIO EDISON CO.	12.6	5.5	-8.3	0.345	8.7	3	1	75	67	70	212

CHAPTER 3

Competitive Issues Facing the Electric Utility Industry

HISTORICAL PERSPECTIVE

Understanding the nature of today's electric utility market requires an awareness of how the industry has evolved. The Public Utilities Holding Company Act (PUHCA), enacted in 1935, is generally acknowledged as the basis from which the electric industry has developed. PUHCA confines the activities of utility holding companies to specific geographic areas, bars diversification into unrelated businesses and gives the Securities and Exchange Commission jurisdiction over holding company investments and the structure of the company's board of directors.

Before the holding company act, 13 holding companies controlled 75 percent of the nations investor-owned electric utilities. They engaged in transactions with their subsidiaries that defrauded customers and diluted stock, hurting small investors. The legislation acknowledged the persistent recommendations of Samuel Insull, then president of the National Electric Light Association. From as early as 1898, Insull had consistently preached exclusive licensing of utilities and fair profit pricing.

Monopolies were created because they made economic sense. Electricity generation and supply has several unique characteristics which make the protection afforded by a monopoly market virtually essential.

- o The supply of electric power and energy to the public at large is affected with the public interest.

- o Large investments in generating stations were required in order to achieve economies of scale and provide electrical energy at the lowest possible cost.

- o Extensive distribution networks are required in order to efficiently sell the electricity produced.

A regulatory scheme has evolved to implement the intent of the holding company act. Electric utilities are subject to over-site by regulatory commissions with respect to the adequacy and cost of the service these utilities provide their customers. The "regulatory compact" provides exclusivity in specified areas and the opportunity to earn a fair rate of return on investments dedicated to public service. The utility accepts the obligation to serve any customer within the certified territory and limitations on the rates of return allowed through electric rate reimbursement.

During the last fifty years, the "regulatory compact" worked well as the use of electrical energy increased by more than 4,000 percent[1]. As the demand for electrical energy exploded, utilities were able to supply increasing amounts of power at steadily decreasing cost. Fuel prices were stable, and technological improvements increased generating efficiencies, and scale economies in both generation and distribution. During the period from 1926 to 1987, the average real residential price for electricity decreased from about 20 cents per Kwh to about 3.5 cents per Kwh, in constant, 1972 dollars[2].

Beginning in 1970, several significant changes impacted the environment within which electric utilities, regulatory commissions and the public coexisted in mutual prosperity. The most important of these changes included the following:

- Previously rapid improvements in fossil-fueled generating technologies slowed considerably.

- More severe pollution emission standards were enacted including, the National Environmental Policy Act and the Clean Air Act. This legislation effectively increased the cost of fossil-fueled generation facilities and

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[1] Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1970, EEI Publication No. 73-34, p. 60, Table 19.

[2] U.S. Department of Energy, Energy Security - A Report to the President of the United States, March 1987, p. 133.

decreased efficiencies.

- o The cost of energy fuels increased substantially. Oil prices increased from $3 per barrel to $30 per barrel.

- o Licensing and certification requirements increased the lead time for new plants from three to four years to six to ten years.

- o The economy's accelerating inflation and increasing cost of capital contributed to major increases in construction and interest expenditures.

- o The growth in electrical demand slowed significantly.

PUBLIC UTILITY REGULATORY POLICIES ACT

The Arab oil embargo of 1973, together with increasing costs to generate electricity, produced a national awareness that demanded political initiative. One response was the Public Utility Regulatory Policies Act of 1978 (PURPA).

PURPA was designed to encourage conservation and efficient use of resources, promote development of cogeneration and small power production, and ensure energy independence and diversity. PURPA created a market for power produced by cogenerators and other Qualifying Facilities (QFs) by requiring utilities to purchase power, from these facilities, at the utility's incremental cost. In 1980, the Federal Energy Regulatory Commission (FERC) established that a utility would purchase QF power at a rate equal to the utility's "avoided cost" - the most expensive internal source of marginal power available.

Some states applied the avoided cost concept so as to encourage an oversupply of uneconomic energy sources, but PURPA legislation did result in several positive outcomes:

- o Utilities were forced to overcome their reluctance to deal with alternative energy power sources.

- The legislation demonstrated that power generation can be decentralized yet compatible with long distance transmission.

FERC NOTICES OF PROPOSED RULE MAKING (NOPRs)

In March of 1988, the FERC formally initiated a process that not only addresses the implementation of PURPA, but also accelerates the alteration of the U.S. power supply business. The FERC issued three Notices of Proposed Rulemaking (NOPRs) which cover the following topics: the pricing of cogenerated power, competitive bidding for new generation, and relaxed regulation for independent power producers or IPPs.

The first NOPR, "Administrative Determination of Full Avoided Cost, Rates for Sales of Power to Qualifying Facilities, Interconnection Facilities" stipulates that utilities should not be required to pay for QF capacity that is not needed. Further, the NOPR suggests that state regulators consider non-price factors, such as the QF's reliability, financial stability, and the ability to dispatch QF power, in calculating avoided cost. The NOPR would, in fact, require states to make public the methodology used to determine avoided cost.

The second NOPR, "Regulations Governing Bidding Programs" proposes that states use a formal bidding process to establish avoided cost and procure future power supplies. Several states have already implemented this proposal, most notably Virginia. During 1989, Virginia Power (a subsidiary of Dominion Resources) selected new power projects, totaling over 2,000 Mw[3], through a competitive bidding process. Green Mountain Power Corporation, of Vermont, initiated a bidding system in 1988 through which conservation and load management projects are proposed.

The bidding rulemaking includes two proposals for comments only. These proposals are important because they address the contentious issue of transmission or "wheeling" of power from one service area to another. The proposals would require that utility participation in a bidding process be dependent on its willingness to wheel the power of all other bidders, subject to reliability and economic dispatch considerations. These proposals address both "wheeling-in" and "wheeling-out" scenarios. "Wheeling-in" applies to utilities who submit bids to supply the capacity needs of another utility. The bidding utility would be required to provide firm transmission service for successful bidders that are located within the bidding utility's own service territory. "Wheeling-out" applies to utilities that would submit a proposal to supply their own capacity needs.

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[3] "Virginia Power Urged to Build", Engineering News Record, July 6, 1989, p. 12.

These utilities would be required to wheel power to adjacent service areas for unsuccessful bidders who wish to sell to another wholesale purchaser.

The third NOPR, "Independent Power Producers", defines an IPP as a "generating entity (other than a QF) that is unaffiliated with the franchise utility in the area in which the IPP is selling power, and for other reasons lacks significant market power." Significant market power is defined as the possession of transmission facilities that are essential to the IPP's customers. This NOPR would also relax Federal Power Act requirements for IPPs. The NOPR proposes to streamline the requirements for IPP filings regarding the sale of facilities, the transaction of securities, and the issuance of securities. It would remove restrictions on interlocking directorates and exempt IPPs from having to follow standard accounting and procurement requirements. The NOPR would also relieve IPPs of requirements to file annual reports and would establish lower FERC filing fees. The NOPRs could lead to a substantial competitive advantage for IPPs. By relieving certain Federal Power Act requirements IPPs could use a greater share of debt financing while regulated utilities would continue to be required to utilize more expensive equity financing. Relieving IPPs from restrictions involving interlocking directorates and security transactions gives them greater flexibility compared to utilities. And, the reduction of filing requirements and fees would give IPPs a direct cost advantage.

PRUDENCY DISALLOWANCES

The energy crises, brought on by the Arab oil embargo, together with expectations that electrical demand would continue to grow at the historical rates, lead many utility managers to commit their company's resources to nuclear construction programs. Nuclear power promised a new source of scale economies and significantly lower fuel cost.

Although nuclear technologies were somewhat untried, the environment that had been nurtured by rate-of-return regulation did not condition utility managers to be wary of risky technologies or possible cost overruns. Managers believed the "regulatory compact" would result in rates that would yield enough revenues to cover costs and provide a reasonable profit.

Table 3.1: Selected Nuclear Reactors and Year of Unit Order and Commercial Service

UNIT	UTILITY	YEAR of ORDER	YEAR of SERVICE
Braidwood 1	Commonwealth Edison	1973	1987
Braidwood 2	Commonwealth Edison	1973	1988
Byron 1	Commonwealth Edison	1973	1985
Byron 2	Commonwealth Edison	1973	1987
Clinton	Illinois Power	1973	1987
Nine Mile Point 2	Niagara Mohawk	1972	1988
Donald C. Cook 1	Indiana & Michigan (AEP)	1969	1975
Donald C. Cook 2	Indiana & Michigan (AEP)	1969	1978
Pilgrim	Boston Edison	1967	1972

Source: World Nuclear Performance, July 1989
Nuclear Safety, January - March 1989

The decisions to pursue relatively untested nuclear technologies in an inflationary economy, together with radical changes in regulatory requirements, affecting plant design forced state utility commissions to reject traditional rate-of-return policies and adopt a more restrictive approach. Commissions questioned the foresight of utility planners who had developed the demand forecasts that initiated plant construction. The prudence of utility management was challenged with regard to cost and schedule control. Finally, the commissions slashed rate requests, and laid the burden of costly overruns on the utilities' stockholders. Table 3.2, reproduced from a report in Nuclear Industry, illustrates the significant value of nuclear plant disallowances.

Table 3.2: Disallowances By State Regulators for Nuclear Units (1980-1986)

UNIT	$ MILLIONS
Wolf Creek	1,641.0
Waterford 3	284.0
Summer 1	123.0
Susquehanna 1	287.0
Susquehanna 2	560.0
San Onofre 2 & 3	328.0
Millstone 3	353.0
Limerick 1	368.9
Grand Gulf 1	49.0
Fermi 2	680.0
Callaway 1	421.7

Source: Oak Ridge National Laboratory

Rates were increased, but utility commissions did not fulfill management expectations that new rates would completely cover the utilities' investment. Reimbursement of utility investment in costly nuclear capacity additions, plus a fair rate of return, was made more difficult in view of other utilities' adoption of non-nuclear and demand management strategies. In the Southwest, some utilities expanded with new and more traditional coal-fired technologies. Wisconsin used load-shifting programs and time-of-use rates to encourage conservation as a substitute for expanding capacity.

The risks associated with "after the fact" over-site by state regulators have contributed to extremely conservative projections of load growth and a general reluctance by utilities to invest in new base-load capacity. This risk-averse approach, especially in areas where electrical demand is now growing at a faster pace, emphasizes the need for alternatives to large new generating units. Modular facilities such as those supplied by independent power producers, and demand management programs have become critical components of utility strategy to meet the obligation invoked by the "regulatory compact", that is, to provide economic, reliable power to anyone within the certified service area.

TRANSMISSION ACCESS

Perhaps the most important issue impacting the competitive environment is access to transmission facilities. The ultimate goal of open transmission access is to allow any potential supplier and any potential customer the ability to obtain the best possible prices for electrical energy. There are several different types of wheeling which must be considered and differentiated. The four most important are:

1. Utility to utility - This form of wheeling has been in place for an extended period and is the most common form in the U.S. today.

2. Utility to end user or wholesale customer on another utility's system - This has become much more prevalent in recent years. One of the more publicized cases involved the city of Geneva, Illinois which was able to bypass its traditional supplier, Commonwealth Edison, and contract to wheel its power from a Wisconsin utility.

3. Private generator to a utility which is not the utility serving the private generator's service territory - About 500 Mw of contracted power was canceled by Virginia Power primarily because of difficulties in arranging wheeling agreements with a West Virginia utility.

4. Private generator to private user, both of which may, or may not, be on the same utility's system - this potentially represents the greatest threat to the traditional modus operandi of the regulated electrical utility system. Cogenerators, given the added incentive of avoided cost purchases by service area utilities (PURPA 1978), have grown explosively by providing process steam and power to industrial customers. Cogentrix Inc., which designs, builds and operates standardized coal-fired cogeneration plants, was the fastest-growing privately-held company in the U.S. during 1989, according to Inc. magazine.

Utilities have long understood the need for a transmission system that through interconnections with other utilities, improves the capacity and reliability of the entire electrical grid. Substantial savings have been achieved through inter-utility coordination and pooling. One study shows benefits in excess of $15 billion per year during the last few years. Close to 75 percent of these savings are due to reductions in capital investments. If not for interconnections between utilities approximately 14 percent more generating capacity would be required to maintain adequate reliability[4]. The U.S. transmission system has improved steadily over the past several years. Allowing non-franchised power producers access to this system is not only critical to their success, but also necessary in order to realize the goal of providing competitively generated power to any potential electrical customer.

There are several significant problems associated with transmission access. Political and economic pressures are forcing regulators to develop strategies that deal with these problems to achieve a more competitive environment. Some of the more complex obstacles to transmission access include the following:

- o Traditional coordination between suppliers who, in a open transmission access environment, would be competing for the same resources and customers will be more difficult.

- o Transmission (and generating) capacity requirements will vary with load responsibilities that may depend on contracts with customers negotiated several years in the future.

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[4] John A. Casazza, "Free Market Electricity: Potential Impacts on Utility Pooling and Coordination", <u>Public Utilities Fortnightly</u>, February 18, 1988, p. 17.

- The ability of customers to switch from one supplier to another will require continual adjustments to transmission and capacity plans and programs.

- Voltage regulation and reactive dispatch techniques, utilized by utilities to maintain proper voltage control to consumers, will be difficult to enforce with IPPs.

Independent power producers who address these issues in a responsible manner are more likely to gain access to the distribution system that is so critical their success.

THE COMPETITION

Utilities must accept the dynamics of the electrical power market and implement competitive strategies if they intend to survive. These strategies must first recognize exactly who the competition is. The issues and trends described above have contributed to the creation of new competitors to the monopolies formed by the 1935 Public Utilities Holding Company Act. The following provides a brief description of these and other major competitors who will contend for future kilowatt-hour sales.

Competitors can be grouped into three categories which, representatives generally agree, illustrate the spectrum of competition faced by the electrical industry[5].

1. Other energy suppliers - this includes natural gas and oil, and substitute energy sources such as solar heat, wind power and geothermal power.

[5] L. M. Morman, N. Emanuelson, D. Horgan, Competition: Pressures for Change, Electric Power Research Publication, EM-5226, Research Project 2381-6, June 1987, p. 3-1.

2. Other electricity suppliers - this group includes other utilities, independent power producers and foreign suppliers such as Canada and Mexico.

3. Customers - this group affects electrical demand through conservation and, in the case of bulk power users, cogeneration.

Other Energy Suppliers:

Of the other energy suppliers, natural gas distributors are currently the most formidable competitor. The gas industry is moving aggressively, through increased advertising and other marketing activities, to capitalize on its price advantage and supply availability. Natural gas distributors compete directly with electric suppliers for the space heating and water heating markets. The industry has made considerable progress in improving the efficiency of space heating equipment. Over the last ten years, the average efficiency of gas-fired residential space heating systems has grown from 67 to over 90 percent.

In the longer term, technological developments will steadily reduce the cost and improve the efficiency of energy alternatives such as solar heating, photovoltaic cells, fuel cells and geothermal power, to name just a few.

Other Electricity Suppliers:

Risks associated with the construction of new base-load power projects including increasingly conservative rate-of-return decisions; federal and state regulations designed to stimulate a more competitive environment; technology which has improved the efficiency of small power plants; and inexpensive hydro-electric power have combined to make this group of competitors the most important in today's electrical market. And, based on several studies, the U.S. generation capacity must expand significantly in order to meet the predicted demand for electrical energy. A recent Department of Energy (DOE) study concludes that 200,000 Mw of capacity must be added by the year 2000[6]. Only one-half of this capacity is actually planned or under construction. According to NERC's 1989 Reliability Assessment, more than 20 percent of the planned capacity will be supplied by non-utility generators.

Utilities have avoided committing their resources to new power projects. They recognize the inclination of public utility commissions to punish the corporations' stock-

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6 Jason Makansi, "Trends and Technology Update", Power, October 1989, p. S6.

holders for the types of over-runs experienced with recent nuclear units. Purchased power has therefore become a major element of utility strategy in providing for the demands of its constituents. Utilities obviously seek the most economical supply of power to meet these demands.

Those utilities which are burdened by expensive capacity are attacked from two fronts. On the one side, wholesale power opportunities are reduced due to the high fixed costs embedded in electrical rates. These opportunities are further reduced as a result of the hugh interconnected transmission network which facilitates the exchange of power with a larger number of producers. Canada and Mexico are among the electric generators which are able to supply inexpensive power to the U.S. grid. Net power imports from these countries has increased at an average annual rate of 25 percent since 1970[7]. On the other side, industrial and large commercial customers abandon the franchise area for more favorable service territories. In fact, inter-utility competition to relocate large industrial customers is intensifying.

Independent power producers have had startling success moving into the electric generation market. PURPA and FERC regulations provided the initial opportunities. The need for new capacity and utility risk aversion has nourished continuing growth.

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[7] L. M. Morman, N. Emanuelson, D. Horgan, Competition: Pressures for Change, Electric Power Research Publication, EM-5226, Research Project 2381-6, June 1987, p. 3-4.

Independents are predicted to add between 6,000 and 7,000 megawatts of electrical energy to U.S. capacity between 1990 and 1993[8].

IPPs sell power to specific industrial customers and franchise utilities. Stable load patterns, improved efficiencies of small generating facilities, and reduced administrative costs give IPPs significant cost advantages over regulated power projects. Utilities have established unregulated subsidiaries that operate generating plants in other service territories. Architect engineers are bypassing their traditional customers, the utilities, with the intent of becoming direct suppliers of electrical energy. Manufacturers such as Dow Chemical Company have also created subsidiaries to tap into the rapidly emerging market for independent power. As access to transmission networks improves, large industrial customers and utilities will pursue the most economical power supplies, wherever they are generated. Independents will certainly be competitive.

Customers:

In a period where new capacity carries with it enormous risks to utility

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[8] Theo Mullen, "Unseating the Electrical Utilities' Monopoly", The New York Times, March 11, 1990, p. F-12.

stockholders, demand management programs have become another important element of utility strategy. Reducing or shifting demand is less expensive than building new plants. Customers who participate in shifting electrical usage to non-peak periods, or voltage reduction during peak loads, represent a strategic advantage. Companies can avoid the need to add additional capacity and thus hold the line on costs and provide greater reliability where customers participate in demand management programs. These programs are especially attractive where commercial and residential customers account for the majority of electric sales. These customers have less bargaining power in terms of bypassing the franchise utility, but their electric usage is more likely to exhibit extreme spikes. In these situations, inadequate reserves could impact system reliability and cost, thus affecting all customers, including the bulk power users who have significantly more bargaining power in the open market.

Industrial customers who require process steam and or large amounts of electrical power represent a significant competitor in the electricity generation market. Many of these customers can reduce operating cost by generating their own steam and power through cogeneration. This effectively removes the cogenerating customer from the franchise utility's rate base. Cogenerators represented 3.4 percent of the total U.S. generation in 1986, an increase of almost 12 percent over the 1985 figure[9]. These

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[9] Betsy DeCampo, Donna A. Flint, Catherine Norris, "Non-Utility Power Supply", Electric Perspectives, Summer 1988, p. 24.

companies are not only backward integrating into power production, but are potentially able to sell excess power off-site. PURPA provided cogenerators an important incentive by requiring utilities to purchase excess power at the utilities's avoided cost, which typically was significantly greater than the actual cost to generate the power. The value of this incentive has declined during the past few years, but opportunities to sell excess power at substantial margins still exist. In addition, with improvements in transmission access, cogenerators will increase the number of these opportunities presenting a considerable threat to electric utility markets.

A FRAMEWORK FOR DEVELOPING COMPETITIVE STRATEGIES

The Electric Power Research Institute (EPRI) has sponsored a number of studies which address the application of strategic planning for electric utilities. This section provides a framework for developing competitive strategies, adapted from an EPRI sponsored study entitled "Competition: Pressures for Change". Many of these elements of competitive strategy are explored in greater depth in the case analyses that follow.

1. Determine the best business opportunities.

   a. Unbundle the company's functional activities. Determine the cost and customer value associated with each activity.

   b. Identify the most attractive customers.

2. Determine how the company should position itself to compete.

   a. Identify the competitive forces in the industry and how they affect the organization. These forces should not be viewed too narrowly. Electric power producers must evaluate the level or intensity of competition, the threats from substitutes, the bargaining power of customers and the threats of new entrants.

   b. Determine the key success factors that will distinguish the winners from the losers.

   c. Assess how the company is doing in relation to its competitors. Articulate the strengths and weaknesses of each competitor and the actions the company must take to improve its position.

d. Understand the company's ability to react to competition. Sensitivity analyses and contingency planning should assess possible regulatory actions, major customer loss or extended plant outages and the impact of these events on corporate income and survival. Recognize the capability of competitors to deal with or react to similar events.

3. Understand the customer. Market segmentation techniques can be used to divide customers by their characteristics, target the most attractive customers, focus on their individual needs, and develop relationships that effectively create a competitive advantage.

   a. Develop focused information gathering programs and provide the necessary resources to continually upgrade and maintain these programs.

4. Among the strategies available to the electric utility industry, cost-based strategies include two major categories: pricing strategies and capital restructuring.

   a. Price products to gain volume and production economies. Provide incentive rates, particularly to bulk customers which are most vulnerable to attacks from competitors.

b. Aggressively defend markets.

c. Plow-back sufficient funds to maintain or reduce the cost of goods sold.

d. Utilize sale-leaseback, and other asset restructuring mechanisms to reduce interest expense and maximize stockholder value.

5. Focus strategies include targeting attractive customer segments, creating customer switching costs, and diversifying utility operations. The goal of focus strategies is to create a distinctive, long-term strategic advantage. Selected customers will be willing to pay premium prices to obtain the perceived additional value offered by a focused utility.

CHAPTER 4

American Electric Power Company (AEP)

OPERATIONS AND COMPARATIVE DATA

Table 4.1: Growth in Kwh Sales, 1986-1988

ANNUAL PERCENT INCREASE IN Kwh SALES (1986-1988)	-0.8 %
TOTAL ANNUAL PERCENT INCREASE IN REGIONAL Kwh SALES (1986-1987)	
EAST NORTH CENTRAL (ENC)	3.9 %
SOUTH ATLANTIC (SA)	4.6 %
EAST SOUTH CENTRAL (ESC)	2.7 %

Sources: AEP 1988 Annual Report

EEI Statistical Yearbook, 1987

Table 4.2: Composition of Electric Customers

	ENC '87	AEP '88	AEP '87
RESIDENTIAL	30.74	24.63	24.94
COMMERCIAL	23.79	16.85	17.15
INDUSTRIAL	42.08	37.37	37.34
WHOLESALE		19.81	19.18
MISCELLANEOUS		1.34	1.39
STREET, HIGHWAY. LTG.	0.64		
OTHER PUBLIC AUTH.	2.60		
RAILROADS	0.11		
INTERDEPARTMENTAL	0.04		

Sources: AEP 1988 Annual Report

EEI Statistical Yearbook, 1987

Table 4.3: Type of Generating Capacity as a Percent of Total Capacity

	ENC '87	AEP '88	AEP PROJ.
HYDRO	2.45	3.71	3.45
CONVENTIONAL STEAM	79.12	86.83	87.76
NUCLEAR STEAM	17.14	9.46	8.79
INTERNAL COMBUSTION	1.28	0.00	0.00

Sources: AEP 1988 Annual Report
EEI Statistical Yearbook, 1987

American Electric Power (AEP) is an investor owned electric utility company composed of eight operating subsidiaries. Revenues in 1988 were more than $4.8 billion. Operating income was 21 percent of sales or $1.02 billion. Net income was 13 percent of sales or $627 million. AEP's subsidiaries include the following:

Chapter 4: American Electric Power Company

Appalachian Power	Kingsport Power
Columbus Souther Power	Michigan Power
Indiana Michigan Power	Ohio Power
Kentucky Power	Wheeling Power

AEP operates in the states of Michigan, Indiana, Ohio, West Virginia, Virginia, Kentucky and a small area in Tennessee. The region is referred to by AEP in its 1988 annual report as America's industrial heartland.

The strength of the industrial economy in the region served by AEP is a significant contributor to AEP's health and rate of growth. Evidence of this relationship is supported by the following statistics:

The value added in manufacturing in Indiana, Ohio and West Virginia increased by 33.3 percent from 1982-1986 compared to a 25.7 percent increase for the U.S. in general.

Durable goods production in Ohio rose by 9.5 percent annually during the period from 1982-1988 compared with a 7.1 percent annual growth rate for the U.S. in general.

The average annual growth of manufacturing employment in AEP's service area (1.1%) almost doubled that of the entire U.S. (0.6%) over the past six years.

AEP has experienced a 4.7 percent annual increase in Kwh sales to its industrial customers and a 4.2 percent annual increase in commercial sales during the period from 1983-1988. AEP's Kwh sales to industrial customers have increased from approximately 29.9 percent of total sales in 1983 to 37.4 percent of sales in 1988. Commercial sales have increased from 13.8 percent to 16.9 percent of the total Kwh sales. Table 2 provides a complete breakdown of AEP's Kwh sales composition.

Total AEP Kwh sales have actually decreased since 1986. Table 4.1 indicates that sales during the period from 1986-1988 decreased by 0.8 percent while sales in the three geographical regions which AEP serves increased by as much as 4.6% (1986-1987)[1]. During the period from 1983-1988 AEP's total Kwh sales peaked in 1984 at 115,216 million Kwh, otherwise sales have been relatively flat with 1983 sales of 104,219 million Kwh and 1988 sales of 104,744 million Kwh. These statistics can be contrasted with other utilities which serve the region:

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[1] Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry / 1988, November 1989, Number 56, Tables 41A and 41B, pp. 47-48.

Table 4.4: Comparison of Annual Kwh Sales Growth Rates (Percent)

	1986-1988	1983-1988
American Electric Power	**-0.8**	**0.1**
Centerior Energy	0.8	3.2 *
Detroit Edison	3.8	3.6
PSI Holdings	4.2	2.5
CMS Energy	4.3	3.0 *
Cincinnati Gas & Electric	4.6	4.1
Dominion Resources	5.1	4.6
Northern Indiana Public Service	7.0	NA
IPALCO Enterprises	7.6	5.2
DPL	8.1	6.0 *
Kentucky Utilities	9.9	5.8
Southern Indiana Gas & Electric	10.7	5.7
Ohio Edison	12.6	7.9
Allegheny Power System	17.1	6.0

Source: Company Annual Reports, 1988

* Percent growth from 1984-1988

AEP's weak sales growth can be attributed to its wholesale market. Sales of wholesale Kwh peaked in 1984 at 40,186 million Kwh. In 1988 wholesale electricity sales were one half of the 1984 peak and had decreased at an annual rate of 17.9 percent. In 1984 electricity sales for resale represented close to 35 percent of AEP's total Kwh sales. In 1988 only 20 percent of AEP's Kwh sales were to other utilities. Table 4.5 provides data on the annual decrease in Kwh sales to the wholesale market for each of four major AEP subsidiaries.

Table 4.5: Annual Percent Decrease in Kwh Sales to Wholesale Market for Major AEP Subsidiaries, 1984-1988

Kentucky Power	-28.0
Indiana Michigan Power	-20.3
Ohio Power	-17.4
Appalachian Power	-13.3

Sources: Company 1988 Annual Reports

Indiana Michigan Power Company's 1988 Annual Report notes the loss of a major wholesale customer in 1987. The contract called for Indiana Michigan Power to provide 400,000 kilowatts of energy to an unaffiliated utility. In addition, another wholesale customer provided notice of termination and requested transmission wheeling arrangements with the company.

AEP's generating capacity peaked in 1986 at 23,486 megawatts. AEP generated 110,203 million kilowatt-hours during that year and had a margin of 6.5 percent during the system's peak load in August. Capacity has since declined by 3.3 percent to 22,704 megawatts. At the same time peak demand has increased by 1.3 percent, leaving AEP with only 1.5 percent of reserve capacity. This situation combined with AEP's high operating and maintenance costs and consequent non-competitive pricing provide the most likely explanations for AEP's loss of wholesale customers. Table 4.6 compares AEP's operating costs and net income as a percent of total sales to other utilities serving the geographical region.

Table 4.6: Average Operating Costs & Net Income as a Percent of Total Revenues, 1986-1988

	COGS	NET INCOME
Northern Indiana Public Service	58.2	4.4
American Electric Power	**56.4**	**11.2**
PSI Holdings	54.5	8.4
Allegheny Power System	54.1	10.5
Southern Indiana Gas & Electric	50.2	12.0
CMS Energy	49.3	12.7
Dominion Resources	49.3	13.0
Cincinnati Gas & Electric	48.0	12.8
Centerior Energy	47.5	12.0
DPL	47.1	12.4
Kentucky Utilities	47.0	13.1
Detroit Edison	40.4	7.4
Ohio Edison	34.5	18.4
IPALCO Enterprises	33.0	18.6

Source: Compact Disclosure

Peak demand in the area serviced by American Electric Power (East Central Area Reliability Coordination Agreement - ECAR) is expected to increase at an annual rate of 1.7 percent[2]. AEP's 1988 system capability was 22,704 Mw. AEP's 1988 operating margin was 2 percent above the peak demand. An additional 1,300 Mw were added to the system's capacity when Rockport's Unit 2 came on line in 1989. AEP's participation in the Zimmer plant will add 330 Mw of capacity in 1991 when the plant commences commercial operation. Even with this additional capacity AEP will be operating with a 9 percent margin. AEP's projected margin is significantly less than the 15 to 20 percent that is considered prudent in order to maintain reliability and system maintenance[3]. If growth occurs as projected AEP will require additional capacity within five years.

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[2] North American Electric Reliability Council, 1989 Reliability Assessment, September 1989, p. 53.

[3] Richard Myers, The Need for Power, Nuclear Industry, p. 26.

Table 4.7: **Comparison of AEP and Regional Utility Capacity Margins & Load Factors During 1988 (Percent)**

	Capacity Margin	Load Factor
PSI Holdings	34.5	NA
Allegheny Power System	30.8	70.0
Kentucky Utilities	24.0	55.5
IPALCO Enterprises	14.9	54.7
Dominion Resources	14.6	NA
Detroit Edison	9.9	55.2
Cincinnati Gas & Electric	4.6	55.2
American Electric Power	**1.6**	**57.5**
Centerior Energy	-2.7	60.8

Source: Company 1988 Annual Reports

The strategic implications of AEP's cost position and reserve margins can be characterized as follows:

- o Buyers have moderate bargaining power
- o Threat of substitutes is great
- o Utility has little pricing flexibility
- o Threat from other utilities is great[4]

CASE ANALYSIS

American Electric Power's current situation presents several problems which must be considered in formulating a successful competitive strategy. These problems can be characterized as follows:

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[4] L. M. Morman, N. Emanuelson, D. Horgan, Competition: Pressures for Change, Electric Power Research Publication, EM-5226, Research Project 2381-6, June 1987, p. 4-17.

1. AEP's operating costs restrict its ability to stake out cost based or low cost producer strategies in the short term. The information presented in Table 6 reveals that AEP's operating costs as a percent of sales are among the highest in a group of neighbor utilities. This cost differential has contributed to declines in wholesale power sales which had been a major business segment, representing 35 percent of all Kwh sales in 1984.

2. AEP's capacity margin is inadequate. AEP will not be able to take advantage of industrial growth opportunities without adding more capacity or contracting for more capacity with other utilities. The addition of the Rockport and Zimmer plants will not bring AEP's margin to acceptable levels of reliability.

3. 87 percent of AEP's electric capacity (after the Rockport and Zimmer plants are on line) will be generated from coal fuel. Pending clean air proposals could impose restrictive emissions requirements on all of the nations coal plants. According to a report published in Industry Surveys, March 2, 1989, stringent acid rain legislation would result in the retirement of large portions of the East Central area's capacity.

4. AEP's revenues are extremely sensitive to the region's industrial economy. If

manufacturing continues its robust performance, the predicted 1.7 percent annual increase in peak demand could prove to be conservative. AEP will need to obtain additional capacity to support growth in the industrial segment. The only question is how soon this capacity will be needed. Conversely, a recession will significantly reduce AEP's load factor. The impact of this reduction will be an increase in rates to AEP's remaining residential and commercial customers. This rate increase will result in an obvious incentive to pursue alternatives to AEP's electricity supply.

A strong strategic position in the industrial, highly competitive East Central electric market requires that a utility become the lowest-cost producer it can possibly be. AEP will have to reduce its operating costs in order to maintain not only its current wholesale customers, but also its critical industrial base.

AEP's initiatives in operating cost reduction programs are not apparent from the literature reviewed. Instead, their is an emphasis on a capital restructuring approach.

1. The combination of eight operating utilities into the American Electric Power Company has provided obvious benefits to the overall bottom line. An example of these benefits is provided by the merger of AEP's competitor companies Cleveland Electric Illuminating and Toledo Edison into Centerior Energy. This

merger is forecasted to save as much as $1.3 billion through reduced overhead and more efficient power plant operations[5]. AEP may be able to achieve greater economies by pursuing additional mergers. Edward Tirello of Shearson Lehman Hutton identifies Allegheny Power System as a potential merger candidate[6]. While Allegheny has relatively high operating costs, their generating capacity of 7906 megawatts would increase AEPs capacity by 35 percent, fortifying AEP's reserve margin and providing savings by deferring new construction projects.

2. In January 1989, AEP entered into an agreement to sell and lease-back its interest in the 1300 megawatt Rockport Plant, Unit 2. The proceeds of this sale were used to repay debt and preferred stock and reduce common equity investments. This continues a four year program by AEP to strengthen its balance sheet by reducing high interest long-term debt and preferred stock.

A long term cost reduction strategy must address continuing environmental concerns and increasing demands for tougher clean air and acid rain laws. AEP, like most of the electric utilities in the East Central region, is strongly opposed to more

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[5] John C. Sawhill and Lester P. Silverman, "Your Local Utility Will Never Be The Same", The Wall Street Journal, July 1 1986, p. 6.

[6] Randall Smith, "Shearson Analyst Touts Utility Consolidation As Study Shows Big Savings, but Few Agree", Wall Street Journal, 1988

stringent clean air legislation, claiming the current laws adequately protect the environment. AEP has invested heavily in pressurized fluidized bed combustion (PFBC) projects. The company insists this clean coal technology would be more effective than the scrubbers mandated by proposed legislation.

With nominal reserve capacity and high generating costs AEP is vulnerable to infiltration by competitors. AEP must create a distinctive competitive advantage which will act as a barrier to the competition's entry into AEP markets. Strengthening customer relationships should be a high priority. AEP has implemented various marketing programs collectively known as "Constructive Marketing". These programs focus on attracting new business to the AEP service area, improving customer service and helping AEP accomplish its load management objectives.

1. AEP has established an aggressive program to identify companies which are compatible with existing business and attract these companies to the AEP service area. Thus AEP is involved in the initial and costly decision of industrial companies to locate or expand in AEP's service area.

2. Additional focus strategies which should be considered by AEP for its industrial customers would included:

A. Providing assistance in energy management, and equipment and systems design. This element of a focus strategy creates switching costs, influencing customer's long term energy decisions and creating barriers to entry by other competitors. The most extensive application of this strategy would involve a collaboration to construct cogenerated power facilities and enter agreements for excess power purchases. This is a particularly attractive approach for AEP which can benefit from the additional capacity. This strategy will also reduce the need for new generating facilities as well as the risks associated with full compensation of construction costs in the company's rate base.

- Consumers Power Company, a subsidiary of CMS Energy, has indicated it will not build another utility owned generating plant. Consumers power will rely in part on cogeneration to supply its future needs[7]. CMS Energy holds approximately a one-half interest in the Midland Cogeneration Venture (MCV). Other partners include Asea Brown Boveri, The Costal Corp., Combustion Engineering Inc., The Dow Chemical Co., Fluor Corp. and

[7] Lucien E. Smartt, "The Electric Utility Executives' Forum", Public Utilities Fortnightly, May 25, 1989, p. 86.

Panhandle Eastern Corp. When completed in 1990, the plant will generate 1370 megawatts of electricity and up to 1.35 million pounds per hour of industrial process steam which will be piped directly to the Dow Chemical facility adjacent to the MCV plant.

- o In addition to the MCV, CMS' subsidiary, CMS Generation Company, is developing and investing in independent power generation projects. The company owns portions of energy production projects and facilities in California, Connecticut and western Michigan. This enterprise could potentially present a significant challenge to AEP's future electric sales.

B. Recognizing the industrial segment as the most critical to AEP's long term health, special pricing policies should have a major emphasis in AEP's marketing program. Three of AEP's neighbor utilities highlight this element of their marketing strategy.

- o NIPSCO Industries was the first electric utility in Indiana to offer economic development power rates. Electric sales on these rates reached 826.2 million Kwh in 1988.

- o Cincinnati Gas & Electric credits economic incentive rates for Armco Steel Company's decision to install two electrogalvanizing facilities in its Middletown, Ohio plant. The use of a long term electric service agreement also encouraged Newport Steel Corporation to install an electric induction furnace and continuous steel casting facility in its Wilder, Kentucky plant.

- o Centerior Energy, Toledo Edison's incentive contracts helped bring additional business to the General Motors central foundry in Defiance when GM closed portions of two foundry operations in another state.

3. Residential customers represent 25 percent of AEP's 1988 Kwh sales. This segment is much more captive compared to bulk power users. AEP's residential strategy is similar to many electric utilities. Electric demand is strengthened through increased use of electric heat supplied by efficient heat pumps. Kilowatt-hour sales increased at a rate of 4.2 percent, from 1983-1988, to residences with electric heat versus a 1.6 percent increase to residences without electric heat. This success is notable in view of the competition from the gas industry.

- o Over the past four years, the market penetration of electric space heating in the Kentucky Utilities service area has declined from 84 percent to 60 percent as a result of falling gas prices and aggressive marketing by the gas industry.

AEP provides the typical incentives to capture the residential heating market. These incentives include certified installation and servicing dealerships; low interest company financing; and "Guaranteed Satisfaction" which will convert the customers heat pump installation to a back-up, supplementing non-electric heating, if the customer is dissatisfied for any reason within one year of the heat pump's installation.

4. Other residential programs focus on efficiency and load management. These programs include the all electric "Smart House", the "Switch" electric water heater rental program and "Transtext" time-of-day energy management program.

One characteristic of AEP which certainly distinguishes this utility is the company's extensive transmission system. NERC's 1989 Reliability Assessment indicates the extra high voltage portion of the transmission network in the ECAR region consists of over 2000 miles of 765 kV, over 800 miles of 500 kV and over 11,700 miles of 345 kV transmission. AEP's 1988 Annual Report tabulates the company's energy delivery system as follows: 2,022 miles of 765 kV and 19,700 miles of jointly owned other transmission lines. The data would seem to indicate that AEP owns the ECAR transmission system.

William McCormick, Chairman and CEO of CMS Energy, believes a vertically integrated industry is not an absolute requirement. He is quoted as saying "there is no reason why you can't have an unregulated and competitive generation industry and a transmission and distribution industry that is still regulated."[8] W. S. White, Chairman and CEO of AEP, is a zealous opponent of deregulation. Mr. White's comments include "the people who do the most talking about it (transmission access) pay no attention at all to what this would mean as far as reliability is concerned and unfortunately many of them don't understand the nature of electricity."[9] The strength of White's convictions seems to have had a major impact on AEP's strategy to remain a typical, vertically integrated utility. The realities of the market may force a change of course in the not too distant future.

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[8] News analysis, 1988: The Big Issue Is Deregulation, Electrical World, January 1988, p. 18.

[9] News Analysis, 1988: The Big Issue Is Deregulation, Electrical World, January 1988, p. 20.

CHAPTER 5

Boston Edison Company

OPERATIONS AND COMPARATIVE DATA

Table 5.1: Growth in Kwh Sales, 1986-1988

ANNUAL PERCENT INCREASE IN Kwh SALES (1986-1988)	2.7 %
TOTAL ANNUAL PERCENT INCREASE IN REGIONAL Kwh SALES (1986-1987)	
NEW ENGLAND (NE)	5.2 %

Sources: Boston Edison 1988 Annual Report
EEI Statistical Yearbook, 1987

Table 5.2: Composition of Electric Customers

	NE '87	BE '88	BE '87
RESIDENTIAL	36.49	26.17	25.59
COMMERCIAL	34.91	53.42	54.18
INDUSTRIAL	26.77	14.03	14.87
WHOLESALE		4.69	4.29
MISCELLANEOUS			
STREET, HIGHWAY. LTG.	0.80	1.00	1.07
OTHER PUBLIC AUTH.	0.89		
RAILROADS	0.13	0.69	
INTERDEPARTMENTAL	0.01		

Sources: Boston Edison 1988 Annual Report

EEI Statistical Yearbook, 1987

Table 5.3: Type of Generating Capacity as a Percent of Total Capacity

	NE '87	BE '88	BE '87
HYDRO	11.96		
CONVENTIONAL STEAM	73.02	83.00	80.00
NUCLEAR STEAM	14.15	17.00	20.00
INTERNAL COMBUSTION	0.87		

Sources: Boston Edison 1988 Annual Report
EEI Statistical Yearbook, 1987

Boston Edison is an investor owned electric utility engaged principally in the generation, transmission, distribution and sale of electrical energy. Boston Edison serves an area of approximately 590 square miles. The company's entire service area lies within a 30 mile radius of the city of Boston. The population served by the company numbers approximately 1,500,000. Edison's 1988 revenues were $1.2 billion, with operating income of $160 million and net income of $84 million. Operating income amounted to 13.3 percent of sales. Net income was 7 percent of sales.

Table 5.2 clearly identifies the critical element of Boston Edison's electric sales as the commercial sector. It has been the strength of the commercial segment that has provided the growth in electric demand experienced by Boston Edison, and the unprecedented growth experienced by the entire New England area. Commercial kilowatt-hour sales in New England have been growing faster than any other segment in all other regions of the United States. Since 1983 commercial kilowatt-hour sales have increased at an annual rate of 5.4 percent.

Boston Edison's Kwh sales growth has not kept pace with the rest of the New England region. Since 1984 Boston Edison's sales have grown at a rate of only 2.8 percent. Table 5.4 provides a contrast between Boston Edison and its competitors in the New England region and the Northeast Power Coordinating Council.

Table 5.4: Comparison of Annual Kwh Sales Growth Rates (Percent)

	1986-1988	1984-1988
Niagara Mohawk Power	0.9	-1.4
Boston Edison	**2.8**	**2.8**
United Illuminating	3.8	2.7
Orange & Rockland Utilities	4.1	1.1
New York State Electric & Gas	4.2	3.6
Northeast Utilities	4.2	3.3
Bangor Hydro-Electric	4.3	3.2
Eastern Utilities Associates	4.6	3.4
Rochester Gas & Electric	4.7	0.6
Central Maine Power	5.0	4.0
Central Hudson Gas & Electric	5.3	NA
Consolidated Edison of New York	5.4	3.3
NECO Enterprises	5.4	5.1
Maine Public Service	6.2	4.9
New England Electric System	6.1	3.3
Unitil	7.2	6.4
Central Vermont Public Service	9.6	4.7
Commonwealth Energy System	9.9	4.4
Green Mountain Power	10.3	7.6

Source: Company Annual Reports, 1988

During the period from 1984 to 1988, Boston Edison reduced its wholesale power sales from a peak of 2,328,614 thousand Kwh in 1985 to 614,847 thousand Kwh in 1988. In 1985 wholesale electricity represented 17.7 percent of Boston Edison's Kwh sales. By 1988, only 4.7 percent of electric sales went to the wholesale market. During this same period Boston Edison's generated electric output decreased at an annual average rate of 12.5 percent and purchased power increased by 25.3 percent. It was during this period, on April 12, 1986, that Boston Edison's Pilgrim Station was taken out of service for refueling, repairs and improvements. Pilgrim is the largest baseload unit on the utility's system. It accounts for 20 percent of the company's generating capacity and can provide up to 40 percent of its electrical supply[1]. Pilgrim Station came back on-line in February of 1989. But during the almost two years the nuclear station was out-of-service Boston Edison was required to replace lower cost nuclear fueled generation with higher cost fossil fueled generation and purchased energy from other utilities.

Boston Edison's operating and maintenance costs were among the highest in the region during the period that the Pilgrim Station was off-line. Table 5.5 compares Boston Edison's operating costs other New England utilities.

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[1] Robert Epstein, Pilgrim's Progress, Nuclear Industry, p. 40.

Table 5.5: Average Operating Costs & Net Income as a Percent of Total Revenues, 1986-1988

	COGS	NET INCOME
NECO Enterprises	80.6	3.1
Unitil	65.7	3.9
Green Mountain Power	65.0	7.8
Boston Edison	**59.7**	**8.4**
Commonwealth Energy System	59.5	5.5
Central Maine Power	57.1	7.5
Bangor Hydro-Electric	55.4	7.8
Central Vermont Public Service	51.5	5.0
New York State Electric & Gas	50.4	14.8
Eastern Utilities Associates	48.9	11.6
Maine Public Service	44.5	10.8
Orange & Rockland Utilities	43.6	9.0
Central Hudson Gas & Electric	43.0	16.7
New England Electric System	42.9	6.6
Niagara Mohawk Power	42.3	14.4
United Illuminating	36.8	8.0
Rochester Gas & Electric	36.4	0.5
Consolidated Edison of New York	36.2	11.0
Northeast Utilities	30.1	11.1

Source: Compact Disclosure

Boston Edison's income was reduced by $7.6 million in 1988 to reflect replacement power costs associated with approximately forty-one days of the Pilgrim outage. The company's position was based in part on a report prepared by an independent engineering firm. The report identified Boston Edison actions which were the cause of avoidable delays totaling forty-one days. Based on a phone conversation with a representative from Boston Edison's Investor Relations Office, Boston Edison has agreed that a further $100 million of replacement power, demand side management and maintenance costs will be not be recovered in customer rates. This represents approximately 40 percent of the $225 million the company identifies as replacement power costs.

Pilgrim continues to play a major role with regard to Boston Edison's health and competitiveness. An initiative petition requiring the shutdown of all operating nuclear power plants within the Commonwealth of Massachusetts appeared on the November 1988 ballot. While the initiative was defeated a potent political threat to Edison as well as other nuclear utilities remains. This threat is exacerbated by problems surrounding the approval of the company's off-site emergency preparedness plan, a predicament which also impacts the Seabrook Nuclear Station.

The availability of Pilgrim obviously impacts Edison's ability to meet the increasing demands of its service area. Table 5.6 indicates Boston Edison's 1988 reserve margin was 21.9 percent, without the Pilgrim capacity. The reserve margin includes contracts for the purchase of electric power. A total of 702 megawatts of electrical energy were under contract to various northeast utilities. Sixty-four percent of these contracts will expire by the end of 1991.

Table 5.6: Comparison of Boston Edison and Regional Utility Capacity Margins & Load Factors During 1988 (Percent)

	Capacity Margin	Load Factor
Rochester Gas & Electric	25.3	60.0
New York State Electric & Gas	23.7	63.5
Eastern Utilities Associates	22.0	60.8
Boston Edison	**21.9**	**60.5**
Central Vermont Public Service	19.0	66.0
Niagara Mohawk Power	19.0	NA
Bangor Hydro-Electric	17.5	75.2
Northeast Utilities	17.5	NA
Central Maine Power	17.0	71.0
Consolidated Edison of New York	17.0	NA
Green Mountain Power	14.5	65.2
United Illuminating	11.0	NA
Orange & Rockland Utilities	5.1	49.0

Source: Company 1988 Annual Reports

Peak demand in the region serviced by Boston Edison is expected to increase at an annual rate of 2.2 percent through 1999[2]. At this rate the North American Electric Reliability Council (NERC) predicts that capacity will be adequate only if the following assumptions are realized:

1. Demand management programs save 1600 megawatts by the winter of 1993-1994.

2. 1900 megawatts of Non-Utility Generator (NUG) capability is added to the electric system by 1993-1994.

3. Base load capacity, currently under construction, must come on-line according to plan. This includes the 1150 megawatt Seabrook unit.

Beyond 1993-1994 the member utilities of the New England Power Pool estimate that additional new resources will be required to meet the demands of its constituents. The most likely composition of resources will be additional NUGs, expanded demand management programs, increased purchases from other utilities, and relatively small utility generators.

Boston Edison predicts a need for 3,335 megawatts of peak capacity by the year

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[2] North American Electric Reliability Council, 1989 Reliability Assessment, September 1989, p.70.

2000. This estimate is consistent with the NERC forecasts for growth in the New England region. Edison's strategy to meet this demand is also consistent with the programs outlined by the NERC. Aggressive demand management will save close to 600 megawatts, according to the Edison plan. The bulk of the required capacity, 77 percent, will be supplied by Edison's own electric stations. Existing contracts, in effect up to 2007, will supply almost 135 megawatts. Additional agreements are projected with Hydro Quebec in Canada and Ocean State Power in Rhode Island for approximately 8 percent of Edison's power requirements. The balance will be supplied by cogenerators and small power producers.

CASE ANALYSIS

Boston Edison's most significant challenge, in an increasingly competitive market place, is to maintain an adequate supply of electrical energy and provide this energy to its customers at prices which reflect the availability of attractive alternatives. Several problems must be addressed in meeting this challenge. These include:

1. Political threats to the continued operation of Edison's least cost, nuclear generation facility could, in the worst case, shut down the Pilgrim plant. A more likely scenario will involve the expenditure of scarce financial and management

resources to oppose new referendums and interest-group initiatives.

2. Boston Edison will find it increasingly difficult to control relatively high operating costs (see Table 5.5) as more of its capacity is purchased versus self generated.

3. While commercial customers are not easy targets for potential competitors they do present unique problems such as idle capacity and very steep peak demand. The result of these problems is upward pressure on electric prices.

4. A significant portion of Edison's capacity relies on oil fuels to generate electricity. In fact, the entire region is heavily dependent on foreign oil. In 1988, oil accounted for an estimated 30 percent of New England's electric generation[3]. There are two consequences of this dependence:

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[3] Industry Surveys, Utilities Electric, March 2, 1989, p. U 20.

A. Electric prices are very sensitive to oil prices which have experienced wide fluctuations in past years. This provides little incentive to large electric users who are interested in stable energy prices.

B. Non-Utility Generators (NUGs) generally depend on gas or oil for their generation. NUGs may be more sensitive to fluctuations in fuel prices. This could result in less new NUG facilities being built and the economics may drive existing NUGs out of business. This prospect would be devastating for the New England area which will be increasingly reliant on NUGs for new generation capacity.

Edison management must acknowledge the political environment and continue to communicate the benefits of Pilgrim's capacity. The argument for maintaining Pilgrim in Boston Edison's rate base is compelling. The Pilgrim Station was built for an unbelievable $231 million. The plant has "paid for itself many times over" in fuel savings since it was put into commercial operation in 1972[4]. Nuclear fuel is much less vulnerable to the price fluctuations that have been commonplace with oil fuels. Continued generation of stable supplies of inexpensive electrical energy are dependent on a nuclear alternative.

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[4] Robert Livingston, "Pilgrim's Progress", Nuclear Industry, p. 40, quote from Danielle Seitz, a financial analyst with Smith Barney, Harris Upham & Co.

Boston Edison must make a significant effort to reduce its operating and financing costs. This objective requires Edison's attention on several fronts, many of which have already been addressed according to the company's 1988 annual report.

1. Edison's operations and maintenance expenses account for 60 percent of its revenues, among the highest in the New England area. In 1988 the company implemented a business planning process which is designed to ensure proper resource allocation and tight expenditure control. A neighboring utility, Northeast Utilities, has implemented an "Activities Value Analysis" program. Northeast credits this program with a reduction in its operations and maintenance budgets of $30 million and a trimming of capital expenditures by approximately $25 million. Note that Northeast has the lowest operating and maintenance costs as a percent of sales among the 19 utilities listed in Table 5.5.

2. Close to 80 percent of Edison's kilowatt-hour sales are to commercial and residential customers. This emphasis puts heavy demands on the company's capacity during very short periods of time. During non-peak periods much of the capacity sits idle. Demand management programs are particularly affective in distributing electric loads over longer time periods thus increasing the efficiency of the system and reducing the overall cost of production. Edison has initiated 25 demand management and conservation programs capable of reducing peak

electrical demand by 78 megawatts[5]. In the long term, Boston Edison's aggressive demand management program, coupled with improvements in conservation technologies are expected to reduce peak demand by 600 megawatts or 18 percent of Edison's predicted peak demand in the year 2000.

- Green Mountain Power (GMP) of Vermont, initiated a demand side bidding process which solicits independent proposals for conservation and load management programs. The bidding process allows GMP to compare demand-side costs with competing bids for new power supply resources. GMP's existing conservation and load management programs reduce peak requirements by 10 percent. The rate of peak load growth during the 1990s, is expected to be reduced by 30 percent through implementation of new demand side management proposals.

3. Interest expenses have increased from 39 percent of operating income in 1986 to almost 53 percent of operating income in 1988. Table 5.7 identifies Boston Edison as among the worst of New England's utilities with regard to interest costs. One contributor to this increased expense was the controversy surrounding the Pilgrim Station. In fact, the concern over the potential financial implications from Pilgrim's outage resulted in a down-rating of the company's securities by

[5] Kenneth R. Sheets, "The Coming Power Crunch", U.S. News & World Report, June 19, 1989, p. 50.

three major rating agencies. Again, Edison must give special management attention to Pilgrim's operations. As concerns are alleviated Edison should initiate efforts to reduce its debt, possibly through sale and lease back arrangements. Edison should work closely with the Department of Public Utilities (DPU) to assure that lease payments are fully recovered through electric rates and earnings are adequately protected.

Table 5.7: 1988 Times Interest Earned Ratios for Selected New England Utilities

New England Electric System	0.87
Boston Edison	**2.33**
United Illuminating	2.38
Central Maine Power	2.41
Bangor Hydro-Electric	2.44
Rochester Gas & Electric	2.57
Unitil	3.05
Northeast Utilities	3.09
Maine Public Service	3.10
Eastern Utilities Associates	3.06
Commonwealth Energy System	3.46
Central Vermont Public Service	3.53
Green Mountain Power	3.97

With over 50 percent of its sales coming from commercial customers, Boston Edison has a clear mandate to satisfy the reliability and service needs of this segment.

1. High tech and service industries which populate the Boston area need reliable

power. According to Marc Goldsmith of Energy Research Group, fluctuations in voltage and frequency are "worse than the price going up'[6]. Boston Edison's resource plan calls for meeting the need for reliable energy by maintaining and improving the capacity and availability of its own generation facilities, purchasing power from inexpensive sources, demand-side management programs, and contracting with cogenerators and independent power producers.

The reliability issue represents the greatest opportunity and challenge to Edison's strategy. By focusing on this issue and successfully implementing its resource plan Edison should be able to maintain its commercial base and prevent intrusion by its competitors. Challenges to this strategy include political threats to continuing nuclear operations, oil price fluctuations and failure of demand-side management programs to produce the needed savings.

2. Demand-side management programs are critical to Edison's focused strategy. The success of these programs is dependent on an adequate and thorough analysis of the customer's electrical needs. Edison's "officer call" program is designed to obtain knowledge that is vital in order to meet customer needs. The program involves regular meetings between commercial customers and the company's officers. Discussion concentrates on customer concerns and demand-side

[6] Richard Myers, "The Need for Power", Nuclear Industry, p. 29.

management strategies and reliability improvement programs.

CHAPTER 6

Central Illinois Public Service Company (CIPS)

OPERATIONS AND COMPARATIVE DATA

Table 6.1: Growth in Kwh Sales, 1986-1988

ANNUAL PERCENT INCREASE / DECREASE IN Kwh SALES (1986-1988)	-3.1 %
TOTAL ANNUAL PERCENT INCREASE IN REGIONAL Kwh SALES (1986-1987)	
EAST NORTH CENTRAL (ENC)	3.9 %
WEST NORTH CENTRAL (WNC)	2.6 %

Sources: CIPS 1988 Annual Report
EEI Statistical Yearbook, 1987

Table 6.2: Composition of Electric Customers

	ENC '87	CIPS '88	CIPS '87
RESIDENTIAL	30.74	28.73	26.49
COMMERCIAL	23.79	11.25	10.77
INDUSTRIAL	42.08	40.59	39.32
WHOLESALE		14.02	18.44
STREET, HIGHWAY. LTG.	0.64		
OTHER PUBLIC AUTH.	2.60	5.41	6.24
RAILROADS	0.11		
INTERDEPARTMENTAL	0.04		

Sources: CIPS 1988 Annual Report

EEI Statistical Yearbook, 1987

Table 6.3: Type of Generating Capacity as a Percent of Total Capacity

	ENC '87	CIPS '88
HYDRO	2.45	
CONVENTIONAL STEAM	79.12	100.00
NUCLEAR STEAM	17.14	
INTERNAL COMBUSTION	1.28	

Sources: CIPS 1988 Annual Report
EEI Statistical Yearbook, 1987

Central Illinois Public Service is an investor-owned utility engaged in the sale of electricity which it either generates or purchases, transmits and distributes. Revenues for the 1988 totaled $616 million in 1988 with 81 percent derived from CIPS' electric segment. The company also distributes natural gas through its own system. The gas is either purchased by the company or by the customer through direct arrangements with the supplier. CIPS' services cover an area of 20,000 square miles in central and southern Illinois. Electric service is provided to 306,000 customers and natural gas distribution is provided to 157,000 customers.

CIPS has not benefitted from the economic revival of the industrial heartland as have its neighboring electric utilities. Sales to CIPS industrial customers have increased at an average rate of 0.8 percent since 1983. But this rate of growth does not compare favorably with the 3.1 percent average industrial Kwh growth rate for the East North Central region, or the 3.3 percent growth experienced by Illinois. The same lackluster performance is noted for CIPS's commercial segment where the average growth rates for the ENC region and Illinois were 3 percent and 0.7 percent respectively versus a 1 percent rate of growth recorded for CIPS.

The residential segment has experienced better results. Demand in this segment increased by an average of 1.6 percent during the five year period from 1983-1988 compared to an average increases of 1.2 percent and 0.5 percent for the ENC region and Illinois respectively. The number of residential customers actually decreased by 0.1 percent during the last five years. But the average customer used 9457 kilowatthours in 1988, a 2.4 percent average annual increase over 1984. This is not unusual. Consumers Power (CMS Energy) estimates that baby-boomers, who now dominate the population, consume 16 percent more electricity per capita than did their parents[1].

Demand from CIPS' municipal and cooperative segments also declined. While the

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[1] Kenneth R. Sheets, "The Coming Power Crunch", U.S. News & World Report, June 19, 1989, p.49.

combination of these Kwh sales represent only 5.4 percent of CIPS' total 1988 demand, demand in each of these areas has decreased by at least 18 percent since 1983. In fact, this segment represented close to 18 percent of CIPS's total Kwh sales in 1983. The company's 1988 annual report explains that an agreement was reached with the Illinois Municipal Electric Agency, during 1987, regarding CIPS's municipal customers. The agreement revised the classification of these customers from "electric revenues" to "power interchanged and purchased, net". The report is unclear, but it is assumed that at least a portion of the declining municipal and cooperative demand can be explained by this reclassification.

CIPS' wholesale or "interchanged power" segment experienced the greatest decline over the past several years. This market has declined by an average of 8.4 percent since 1984. The greatest decreases have occurred in the period from 1985 to 1988. In 1985 CIPS supplied 1862 million Kwh for interchanged power. By 1988 only 1214 million Kwh were sold wholesale.

Combining the municipal, cooperative and interchanged kilowatt-hour sales provides another perspective of CIPS' declining situation. Since 1985 the total Kwh sales for these categories has declined by an average of 22.6 percent. The combination of municipal, cooperative and interchanged power represented 31 percent of CIPS' Kwh sales in 1985. By 1988 this segment accounted for only 19 percent of the kilowatt-hours sold by CIPS (Also refer to Table 4.4).

Table 6.4: Comparison of Annual Kwh Sales Growth Rates (Percent)

	1986-1988	1983-1988
Wisconsin Energy	12.6	6.6 *
Wisconsin Public Service	6.9	4.4
Madison Gas & Electric	6.2 #	NA
Commonwealth Edison	5.7 #	NA
WPL Holdings	2.9	1.8 *
Upper Peninsula Energy	2.3	1.6 *
Illinois Power	1.6	0.4 *
Central Illinois Public Service	**-3.1**	**-9.9 ***

Source: Company Annual Reports, 1988

* Percent growth from 1984-1988

\# Percent growth from 1987-1988

During the period from 1985 to 1988 CIPS' total electric system capacity declined at an average annual rate of 1.6 percent or a total of 129 megawatts. CIPS' margin, though decreasing from its peak of 73.3 percent in 1985 to a 1988 margin of 29.7 percent, remains more than adequate. A more disturbing statistic is the decline in CIPS load factor which has decreased from a high of 61.6 percent in 1985 to its current (1988) 53.1 percent.

Table 6.5: Comparison of CIPS and Regional Utility Capacity Margins & Load Factors During 1988 (Percent)

	Capacity Margin	Load Factor
WPL Holdings	0.5	NA
Wisconsin Public Service	13.6	70.2
Illinois Power	19.7	NA
Central Illinois Public Service	**29.7**	**53.1**

Sources: Company Annual Reports
Also refer to Table 4.7

CIPS' costs would not present an explanation of the company's declining sales, at first glance. 40.3 percent of sales seems like an enviable position after reference to

Table 4.6 and Table 5.5. But CIPS is operating in the same territory with Illinois Power and Commonwealth Edison. Note from Table 6.6, that these utilities have the lowest cost of goods among the electric generators operating in the Mid-America Interconnected Network (MAIN). Commonwealth Edison's net interchanged power increased from a negative 4395 million kilowatt-hours in 1986 to a positive 430 million kilowatt-hours in 1988. It is also interesting to note that Commonwealth Edison's cost of power received was reported at 2.13 cents per kilowatt-hour, while its cost to deliver power was 1.21 cents per kilowatt-hour. Both Commonwealth Edison and Illinois Power have recently brought new, nuclear generating units on line:

Commonwealth Edison:

Byron Unit 2	1987	1120 MW(e)
Braidwood Unit 1	1987	1120 MW(e)
Braidwood Unit 2	1988	1120 MW(e)

Illinois Power:

Clinton	1987	933 MW(e)

Commonwealth Edison negotiated a unique arrangement with Madison Gas and Electric Company (MGE) in 1989. For the first time, MGE bought electricity from a non-adjacent utility and had it wheeled to the MGE system.

Table 6.6: Average Operating Costs & Net Income as a Percent of Total Revenues, 1986-1988

	COGS	NET INCOME
Upper Peninsula Energy	69.2	7.8
Northern States Power	64.2	8.1
Wisconsin Public Service	52.6	9.1
Madison Gas & Electric	45.7	9.6
WPL Holdings	45.4	9.9
Wisconsin Energy	42.7	11.8
Illinois Power	41.0	20.9
Central Illinois Public Service	**40.3**	**12.6**
Commonwealth Edison	29.0	17.1

Source: Compact Disclosure

Peak demand in the MAIN region is expected to grow at an annual rate of 1.6 percent through 1998. Total energy usage is expected to grow at an average annual rate of 1.7 percent[2]. These growth projections were increased significantly over previous years to reflect the actual peak demand experienced during extended periods of high summer temperatures. While current and projected future capacity appear adequate, the NERC notes that uncertainties due to weather and load forecast error result in predictions of insufficient reserves by 1994.

The area's reliance on coal generating stations[3] also presents a risk that could have significant impacts on the regions ability to meet future electrical demand. Acid rain legislation could drastically reduce the area's generating capacity. CIPS is particularly vulnerable because 100 percent of its electrical energy is generated from coal.

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[2] North American Electric Reliability Council, 1989 Reliability Assessment, September 1989, p. 63.

[3] According to NAERC's 1989 Reliability Assessment, coal will furnish 56.3% of the electrical energy generated in MAIN in 1998.

CASE ANALYSIS

CIPS' problems are unusual and varied. The utility is an anachronism, displaying a complacency that is totally out of place in a competitive environment. Since 1985 CIPS' capacity has declined by 4.5 percent, its load factor has declined by 13.8 percent , and its electric sales have declined by 17.1 percent. By comparison, Illinois Power has increased its capacity by 13.5 percent and electric sales have increased by 9.8 percent. In addition, Table 6.7 presents an interesting contrast between the two, adjacent utilities:

Table 6.7: Comparison of Total Growth (Percent) in Kilowatt-hour Sales to Specific Market Segments for Central Illinois Public Service (CIPS) and Illinois Power, 1985-1988

	CIPS	ILLINOIS POWER
INDUSTRIAL	1.6	10.4
RESIDENTIAL	3.8	9.1
COMMERCIAL	0.5	9.5

CIPS's 1988 Annual Report indicates "electric generating capacity is expected to meet customer demand through the 1990s". While the projections support this statement, CIPS ignores potential risks including the impact of acid rain legislation. Further, there is no plan to utilize excess capacity either through increasing demand or rejuvenating interchanged power.

CIPS is surrounded by aggressive, potential competitors. Illinois Power and Commonwealth Edison have recently completed costly construction programs. Both utilities have excess capacity and they are working diligently to improve their customer base.

- Illinois Power works closely with the communities in its service area to attract new industry. The company opened its Center for Site Selection in 1989 where an innovative and sophisticated, computer data base combined with laser videos provides extensive information on more than 200 potential sites in Central and Southern Illinois. The Center has is another element of Illinois Power's aggressive program to expand economic development in its service area. In 1989, 10 new employers located in Illinois Power's territory and 35 existing firms expanded. These employers created more than 2000 new jobs. Since 1985, the company's economic development efforts have helped bring 124 firms to Illinois, 192 businesses expanded and more than 18,000 new jobs were created.

Other adjacent utilities, such as Public Service Indiana, are poised to compete in CIPS service area through the creation of cogeneration and independent power producer subsidiaries.

- By 1992, a third 345 kV circuit across southern Illinois will be completed. This line will tie the Gibson plant of Public Service Indiana to the CIPS transmission system[4]. (Also refer to the discussion concerning CMS Energy and its diversification into independent power production.)

In addition to emerging competition, CIPS' total reliance on coal generating stations leaves the company at extreme risk from pending acid rain legislation.

In spite of what appears to be a nescience with regard to market sensitivity, CIPS has improved operating income performance during the period from 1986 to 1988. Operating income increased from 16.8 percent of sales in 1986 to 18.8 percent of sales in 1988. But this improvement did not come from increased production and sales or accomplishments in operating and maintenance cost reduction. Electric revenues have actually decreased since 1986 and operating costs have been stable during the period (see Table 6.5). The improvement was a result of reductions in taxes, from 18.9 percent of sales in 1986 to 15.8 percent of sales in 1988.

CIPS' long term strategy appears to be directed toward an unbundling of its current functions and an emphasis on transmission. Their transmission system is connected to 12 other utilities. A new computer system was recently installed at their North Pana System Control Center. According to CIPS' 1988 Annual Report, this system

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[4] North American Electric Reliability Council, 1989 Reliability Assessment, September 1989, p. 64.

will provide a state-of-the-art energy management capability.

A state-of-the-art electric delivery system will not be enough to survive in an increasingly competitive environment. CIPS must also expand its customer base. The Corridor of Opportunity and Development Act, approved by the Illinois General Assembly in 1986, could be a formidable vehicle for a strengthened economic development program at CIPS. Four corridors have been formed in CIPS' service territory. CIPS should work diligently to attract new business to these corridors through offers of incentive rates and reliable power. A larger customer base, especially in the industrial segment, will improve CIPS' load factor and therefore the efficiency of its current generating capacity. In the longer view the profitability of a transmission company will be directly related to the amount of kilowatts it moves.

CIPS must also hedge against the potential shut-down or derating of its coal-fired facilities. Improving its transmission system is certainly a prerequisite to wheeling reliable power supplies from other generators to CIPS' customers or other connected utilities. Noting that the North American Electric Reliability Council is forecasting inadequate reserves for the MAIN region by 1994, CIPS should also evaluate alternatives to interchanged power. Cogeneration appears to be an attractive option which is not addressed by CIPS' management. By working with industrial customers to identify cogeneration opportunities and construct and operate cogeneration facilities

CIPS can enhance its ability to provide power to other systems in the MAIN region, reinforce relationships with its industrial customers and improve system reliability and customer satisfaction. These benefits can be achieved without large investments in new construction programs, little risk in terms of Illinois Commerce Commission approval of rate reimbursements, and with an added advantage of possibly increasing CIPS' sales of natural gas.

As CIPS moves toward a service orientation the company must become more sensitive to market dynamics. An extensive and permanent market research effort should be undertaken. This effort should produce accurate market segment information, evaluate and identify target customers, and articulate the key buying factors of these customers. In addition CIPS' market research must objectively describe and calibrate the competitive forces that affect the entire industry. Finally CIPS must assess its own strengths and weaknesses and those of its competitors, and design services which create a long term, strategic advantage.

Illinois Power (IP) provides examples of services which distinguish the company from other electric suppliers and strengthen the relationship between IP and its customers:

o IP has established two advisory councils located in different areas of its service territory. The members of these councils represent a broad cross-section of business, consumer, social service, senior citizen, minority and educational interests. The ideas generated by these councils have been instrumental in the improvement of customer service programs.

- IP established a formal Quality and Productivity Program in 1987. Fifty-two QP teams focus their attention on three major areas - power plants, customer service and supporting organizations. During 1989, more than 200 recommendations for improving the quality of service and cost control were approved.

- The company will begin an interactive electronic message service for industrial customer in 1990. The computerized link allows large businesses to adjust natural gas orders, monitor energy usage and determine how overall demand for energy affects their service. The information provided by this system can help industrial customers operate more efficiently.

- A centralized telephone answering service will begin operation in 1991. A single facility will receive reports of gas and electric service emergencies and provide around-the-clock answers to customer questions regarding billing and installation requests. This operation is designed to improve service and lower operating costs by more than $1 million per year.

CHAPTER 7

Summary of Findings

CASE SUMMARY

The intent of this project is to determine whether some added value can be achieved by restructuring the corporate strategy of electric utilities to respond directly to the new competitive forces facing the industry. The information and analyses provided by this paper would certainly support an affirmative response. While the data is not statistically significant, each case analysis identifies a number of obvious opportunities and vulnerabilities which have been addressed by other utilities, within the same or adjacent regions. The superior performance of these firms presents evidence that is intuitively compelling. Consider the following comparisons:

1. **American Electric Power** CEO W. S. White is adamantly opposed to deregulation of the electric utility industry. AEP has followed a traditional and conservative approach to electric sales and succeeded by virtue of its considerable size particularly its transmission capacity. Yet AEP's growth in Kwh sales lag the region's by 4.7 percent and their average net income as a percent of sales ranks tenth among the 14 utilities listed in Table 5.6.

Dominion Resources, operating in an adjacent NERC and EEI region, exhibits a progressive and aggressive approach to electrical generation and distribution. The utility leads the industry in contracting for power produced by QFs and IPPs and it has established a subsidiary that owns portions of 15 cogeneration and independent power projects outside the regulated service territory. Dominion Resources has posted Kwh sales gains that exceed the region's average by .5 percent. Their average net income as a percent of sales ranks forth among the 14 utilities listed in Table 5.6. The utility's cost of goods and capacity margin suggest that the utility is in an enviable position compared to its competitors:

- o Buyers have moderate bargaining power
- o Threat of substitutes is relatively low
- o Utility has short- and long-term pricing flexibility
- o Threat from other utilities is relatively low

2. **Boston Edison** has worked extremely hard to establish a relationship with its customers that effectively creates barriers against competitors. Edison views reliability as the key ingredient to success. The utility has established long term

contracts with inexpensive power producers and they have instituted innovative demand management programs that have been successful in delaying the need for additional expenditures on new, costly capacity. They are also pursuing purchase contracts with independent power producers and cogenerators. Yet, Boston Edison has had major problems with their economical Pilgrim plant. Kwh sales growth, while strong at 2.8 percent per year, lags the region by 2.5 percent. This performance is due almost entirely to declining sales in the wholesale market, which would be the first to suffer when Pilgrim is off-line.

Eastern Utilities Associates' 1988 operating revenues were 31 percent of Boston Edison's. But this utility has moved quickly and aggressively to take advantage of competitive opportunities. One of the major objectives of their strategic plan is to sustain earnings growth through expansion and diversification into non-regulated energy enterprises. EUA Cogenex has made impressive gains in both the cogeneration and energy management markets. This subsidiary owns and operates 15 cogeneration projects producing almost 4,500 megawatts of electrical energy. EUA Energy Investment owns a 15 percent share of a new 16 Mw wood-fired facility in Pembroke, New Hampshire. EUA Ocean State owns a 25 percent share of what will eventually be a 500 Mw gas-fired generating station in Rhode Island. These enterprises have broken new ground in terms of both diversification and innovative financing. EAU demonstrated this same competence in negotiating a buy-out of several utilities' interests in the Seabrook nuclear unit. EUA Power Corporation, a separate subsidiary formed in 1986 for the exclusive purpose of purchasing Seabrook shares, purchased 12 percent of the nuclear unit for just under 25 cents on the dollar of sunk construction costs. EUA Power was permitted to charge qualified market-based rates, and was allowed up to 25 percent return on equity for the first 12 years of operation[1]. It is interesting to note that EUA's times-interest-earned ratio is among the strongest in the group listed in Table 6.7. EUA exhibits a more impressive cost position compared to Boston Edison with cost of goods at 48.9 percent of sales and net income at 11.6 percent. While their demand did not quite keep pace with the region their performance was noticeably better than Boston Edison's despite their 11 percent ownership in the Pilgrim station.

3. The **Central Illinois Public Service** case analysis provides in-depth comparisons of CIPS' performance statistics with its potential competitors, including Illinois Power. But it is worth noting that Illinois Power had "the worst year in our Company's 66-year history" according to the utility's 1989 Annual Report. This result was attributed to the $346 million after-tax write-off related to "unreasonable" Clinton nuclear power plant construction expenditures. Illinois

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[1] Vernon L. Smith, "Electric Power Deregulation: Background and Prospects", Contemporary Policy Issues, Vol. VI, July 1988, p. 21.

Power is a fighter. They have not let financial concerns overshadow their operation. At the same time they cut operating costs by $30 million per year, improving their bargaining flexibility, they have also instituted a comprehensive quality and productivity improvement program, which will help to build a distinctive strategic advantage. It appears that CIPS can benefit from at least one value added service, that is - expanding their awareness of potential competitors.

CONTINUING RESEARCH AND DEVELOPMENT

Relative demand for kilowatt-hours seems to provide a significant indication of utility competitiveness. But this parameter presents at least two problems in terms of its future usefulness in predicting a need for strategic planning and decision making. First, the regional demand must be more closely correlated with the utility's service area. Changes in kilowatt-hour demand for NERC regions, versus the state borders used for this project, and delineated by EEI statistics, should provide better comparative data. Second, kilowatt-hour demand may become an increasingly less important indicator as utilities unbundle their functions to more closely match their strategic strengths with existing markets. Capacity utilization and return on investment parameters may become much more important as this evolution continues.

This project relies almost entirely on data compiled from annual reports and published articles to characterize the needs of utilities and their executive management. Certainly, an important next step must include interviews of company CEOs and managers. Some of the EPRI studies referenced by this project use executive interviews to corroborate the studies' conclusions. While this material has been helpful, the information that was actually documented does not provide the insight which will be needed to develop effective strategic analysis and decision making programs. In addition, while this project does not address the corporate culture as an important element of the corporate strategy, there is no doubt that the corporate culture plays a significant role in a utility's ability to respond to market dynamics. A useful understanding of the corporate culture can only be obtained after a fairly lengthy involvement with the company.

The most obvious strategic opportunities appear to be in the following areas:

- Asset or corporate restructuring can take advantage of the current conditions favoring non-regulated power generators. Returns on investment of between 20 to 30 percent have been realized by the Independent Power Production subsidiaries of utilities such as Dominion Resources of Virginia. In the longer term, the rate of growth of this segment will decline as cost advantages diminish. Care must be exercised with regard to the level of capital investment in independent power generating assets.

- Capacity planning must be integrated with the utility's efforts to build product distinction. The evolving market will make it much easier for power users to negotiate and contract for their electrical requirements, thus accelerating the switching activity of a utility's customer base. The successful competitive utility will have a comprehensive understanding of its own strengths and weaknesses as well as those of its competitors. The utility will distinguish its products and services and erect barriers to prevent competitor encroachment.

- Successful utilities must be cognizant of both the obvious and obscure competitors. Emerging potential competitors in the commercial, municipal and residential markets could include fuel cell, solar power and energy storage manufacturers. Technological improvements could quickly make these options economically attractive leading toward a significant decentralization of power production services.

- Utilities, particularly nuclear utilities, must learn to recognize the benefits of cost control. Resource constraints must be viewed as a competitive edge, not a meaningless restriction that introduces conflict between management and operations.

- Regulated utilities must pursue a more cooperative relationship with the regulator. The "regulatory compact" has resulted in an astounding benefit to both business and the consumer. This extraordinary achievement can not be ignored as the industry is reshaped by competitive forces. Utilities and regulators must agree, up-front, on the definition and boundaries of prudent management. Objectives should focus on risk reduction with the recognition that consumer protection and investor wealth are directly related. A more cooperative and proactive relationship could almost certainly reduce the enormous and wasteful cost that utilities and their constituents bear to argue for or against rate matters.

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