National
Hydroelectric Power
Resources Study

Volume X
November 1981

An Assessment of Hydroelectric Pumped Storage

Prepared by:
Dames and Moore
7101 Wisconsin Avenue
Washington, D.C. 20014

Under Contract to:
The U.S. Army Engineer
Institute for Water Resources
Casey Building
Fort Belvoir, Virginia 22060

Contract Number DACW-31-80-C-0090

National Hydroelectric Power Resources Study

An Assessment of Hydroelectric Pumped Storage

Volume X
November 1981

IWR 82-H-10

SECURITY CLASSIFICATION OF THIS PAGE (When Data Entered)

REPORT DOCUMENTATION PAGE		READ INSTRUCTIONS BEFORE COMPLETING FORM
1. REPORT NUMBER NHS Volume X	2. GOVT ACCESSION NO.	3. RECIPIENT'S CATALOG NUMBER
4. TITLE (and Subtitle) National Hydroelectric Power Resources Study An Assessment of Hydroelectric Pumped Storage		5. TYPE OF REPORT & PERIOD COVERED Final Report
		6. PERFORMING ORG. REPORT NUMBER IWR-82-H-10
7. AUTHOR(s) Dames and Moore		8. CONTRACT OR GRANT NUMBER(s) DACW-31-80-C-0090
9. PERFORMING ORGANIZATION NAME AND ADDRESS Dames and Moore 7101 Wisconsin Avenue, Suite 700 Washington, DC 20014		10. PROGRAM ELEMENT, PROJECT, TASK AREA & WORK UNIT NUMBERS
11. CONTROLLING OFFICE NAME AND ADDRESS WRSC/Institute for Water Resources Casey Building Fort Belvoir, VA 22060		12. REPORT DATE November 1981
		13. NUMBER OF PAGES 520
14. MONITORING AGENCY NAME & ADDRESS (if different from Controlling Office)		15. SECURITY CLASS. (of this report) Unclassified
		15a. DECLASSIFICATION/DOWNGRADING SCHEDULE

16. DISTRIBUTION STATEMENT (of this Report)

Approved for public release: Distribution unlimited.

17. DISTRIBUTION STATEMENT (of the abstract entered in Block 20, if different from Report)

Approved for public release: Distribution unlimited.

18. SUPPLEMENTARY NOTES

19. KEY WORDS (Continue on reverse side if necessary and identify by block number)

Hydroelectric Power
Hydroelectric Pumped Storage
Energy
Peak-load Generating Technologies

20. ABSTRACT (Continue on reverse side if necessary and identify by block number)

"An Assessment of Hydroelectric Pumped Storage" is part of a larger, comprehensive study undertaken by the U.S. Army Corps of Engineers to assess the potential contribution of hydroelectric power resources to the Nation's energy supply. The pumped storage assessment consists of three major areas: (1) An up-to-date inventory of the various pumped storage projects (operational and planned) in the United States; (2) A study of the technological alternatives to pumped storage including new peak-load generating technologies and the "zero kilowatt" technologies of load management and conservation (a major focus of

DD FORM 1473, 1 JAN 73 — EDITION OF 1 NOV 65 IS OBSOLETE

UNCLASSIFIED

SECURITY CLASSIFICATION OF THIS PAGE (When Data Entered) this section is an analysis of the feasibility of each of the alternatives and a comparative cost assessment with pumped storage); and, (3) a regional analysis of the future need for pumped storage (or its alternatives) based on a range of possible regional growth rates, the overall cost competitiveness of each peaking alternative, and the cost of installing the additional base load capacity to support each of these alternatives.

AN ASSESSMENT OF

HYDROELECTRIC PUMPED STORAGE

Prepared for

DEPARTMENT OF THE ARMY
CORPS OF ENGINEERS
INSTITUTE FOR WATER RESOURCES

November 1981

7101 Wisconsin Avenue, Suite 700, Washington, D.C. 20014

ACKNOWLEDGEMENTS

This report was prepared by Dames & Moore with the assistance of several consultants. Mr. James J. Stout, independent consultant of Arlington, Virginia, and formerly with the FPC and FERC, provided valuable guidance and assistance on the preparation of Chapter 1. The Energy Research Group of Cambridge, Massachusetts, contributed major portions of Chapters 3 and 4 and were the overall consultants for defining and evaluating alternatives to pumped storage.

Special thanks are given to the staff of the U.S. Army Corps of Engineers' National Hydropower Study for their review, comment, and counsel, provided over the course of this project.

CONTENTS

CONTENTS (cont'd)

CONTENTS (cont'd)

LIST OF TABLES

LIST OF TABLES (cont'd)

LIST OF TABLES (cont'd)

LIST OF FIGURES

LIST OF FIGURES (cont'd)

EXECUTIVE SUMMARY

1. INTRODUCTION

"An Assessment of Hydroelectric Pumped Storage" is part of a larger, comprehensive study undertaken by the U.S. Army Corps of Engineers to assess the potential contribution of hydroelectric power resources to the Nation's energy supply. The pumped storage assessment consists of three major areas:

- An up-to-date inventory of the various pumped storage projects (operational and planned) in the United States
- A study of the technological alternatives to pumped storage including new peak-load generating technologies and the "zero kilowatt" technologies of load management and conservation (a major focus of this section is an analysis of the feasibility of each of the alternatives and a comparative cost assessment with pumped storage)
- A regional analysis of the future need for pumped storage (or its alternatives) based on a range of possible regional growth rates, the overall cost competitiveness of each peaking alternative, and the cost of installing the additional base load capacity to support each of these alternatives.

The relative cost of fuels versus new construction and the influence of environmental considerations on these cost decisions could direct the capacity expansion plans for each of these regional systems along a wide range of quite different development paths. This diversity could, in turn, produce a wide range of possible future pumped storage capacity additions. Consequently these issues are critical to the results of this analysis.

In this analysis, capacity expansion plans are assumed to be determined by the long-run growth rates of electricity demand, which in turn are influenced by the overall rate of savings and investment in the U.S. economy. This savings and investment rate is presently uncertain, however, particularly in light of the results of newly formulated economic policies. Thus, until the new direction of the U.S. economy becomes clearer, ranges for future growth rates are more appropriate than a specific, targeted growth figure.

For the purposes of this analysis, it was also assumed that high growth in national savings and investment rates (produced by new, national economic policies) would eventually result in an increase in the rates of growth in electricity use. These rates could then lead to higher rates of generating equipment retirement than would otherwise result because the availability of new generating facilities would render the existing stock obsolete. Should a rigorous building program develop, the potential for pumped storage or alternative technology development would increase significantly. However, should the opposite situation materialize, potential development of pumped storage or alternative technology facilities would be minimized.

In the following sections of this summary, a statement of the background of the study is provided, the conclusions of the analysis are summarized, and the major findings of each element of the overall project are outlined.

2. BACKGROUND

Over the next 20 years, the extent to which pumped storage electricity generating facilities will be incorporated into the Nation's regional electric utility generating systems will depend on the interaction of a complex set of engineering and economic factors:

- Growth in the regional use of electric energy and seasonal peaks
- Relative prices of fuels used to generate electricity
- The future course of general price inflation
- Escalation in the construction costs of new powerplants
- The specifics of regional economic development and the generating fuel "mixes" in each region
- Developments in new and alternative technological electricity generation.

The applicability of pumped storage to the future peaking needs of the various geographic regions of the United States is the thrust of this assessment. Today, conventional aboveground pumped storage is a proven technology, subject only to changes in the cost of new construction. In its conventional form, pumped storage is clearly applicable to the regional needs of a wide geographic area of the country (e.g., central United States). However, for some of the other regions, (e.g., Florida) the terrain is too flat, even though a systems need for peaking capacity exists. For these areas, underground pumped storage may be a feasible option (underground pumped storage systems use natural caverns as the "low land reservoirs" and a proximal ground-level site as the upper reservoir). Also, in many parts of the country, other alternatives to the use of pumped storage as a peaking technology are already in place; these include installed oil- and gas-fired plants in systems that may later be adding new base-load plants; and existing, conventional, hydro generating stations with sufficient storage capabilities to permit their operation as peakers (if additional base-load plants can be constructed).

For some regions, both the conventional alternatives and the nonconventional peaking technologies could be added. Many of these alternatives are seen by some policymakers as potentially less costly or environmentally preferable. If cost was the only criterion, it is likely that the lower operating cost of existing peaking capacity (particularly the installed hydro of the Northwest and the existing oil- and gas-fired capacity in the Southwest and South Coastal Pacific regions) would be more attractive than building new facilities. Thus, the long-term applicability of pumped storage to regional requirements for new peaking capacity rests on such factors as the consideration of possible environmental impacts and the future prices of oil and gas versus the cost of pumped storage construction.

The large increase in hydroelectric pumped storage capacity that has occurred over the last 20 years has provided electric utility companies with flexible, reliable plants that are capable of quick startup to meet daily peak energy demands and emergency situations. Although the ratio of pumping energy to generation energy generally ranges from 3:2 to 4:3 for a pumped storage plant, it allows for efficient operation of the larger, more complex fossil-fueled and/or nuclear plants that would otherwise be used only to meet daytime base loads. As a result, net energy savings are realized when base-load plants power storage facilities while simultaneously providing improvements to operating reserve margins during peak-load periods.

Other factors contribute to the attractiveness of pumped storage plants, including the compatibility of pumped storage with nuclear power generation loading during rapidly rising peak loads or in the face of forced outages during peak periods. The low operation and maintenance costs of pumped storage and the steady rise in peak-load to base-load ratios, which was prevalent until the mid-

1970's, are also contributing factors. In general, hydro systems make pumped storage generation attractive because hydro is a renewable source of energy.

Today the potential for future development of hydroelectric pumped storage is somewhat clouded. Major changes in load growth, the shelving of plans for more large nuclear and coal plants, and the emergence of environmental litigation with respect to the siting of pumped storage facilities, have combined to lessen the presumed attractiveness of pumped storage.

3. CONCLUSIONS

This study actually consists of 17 separate regional studies. For purposes of summarizing only, these have been summed into 7 regions of fuel supply commonality and then further summed into a set of national tables. Both the 7 summarized regions and the national results are listed in Task 5 of the report at 5-year intervals for the next 20 years. The details of the computer programs that were written to perform these 17 regional studies are reported in Appendix C.

In the following tables (Tables I through IV) the national results are further summarized and are reported only for the year 2000. Yet it is important to remember while studying these results that these are only summaries of the regional analysis and cannot be taken as proportional for any one region. The distinguishing feature of this analysis is that the supply and demand of any one region has little applicability to any of the others.

For example, the hydro generating capacity surplus of the Northwest (to which, as time passes, more base capacity will be added) is converted by this process into a huge peaking system and cannot be proportionally applied to the steam-coal base-load systems of the Midwest. The Northwest has a long-term surplus of hydro (obviating the need for the construction of pumped storage facilities), while the Midwest has a long-term, chronic need for peaking capacity, thus making it the prime target area for future pumped storage or alternative peaking technology construction.

These two regions cannot be combined because of the physical limitations of moving vast quantities of electric energy 2,000 miles every few hours. It should be further remembered that these regions cannot be coupled because they also have different prospects for growth. In point of fact, this analysis is simply the result of 17 regional studies, and this limitation has been deliberately introduced. We believe it is reflective of the limited ability and real diseconomies in the existing

TABLE I

Maximum Estimated Capacity of Installed Pumped Storage by the year 2000

(if no additional, non-pumped storage is added beyond that planned or currently under construction)

	Projection I(1)	Projection II(2)	Dames & Moore Forecast(3)
Most Favorable Economies for Construction			
W/o Load Management			
Utility announced retirement	250,000*	302,000	180,000
Generic retirement	255,000	302,000	188,000
With Load Management			
Utility announced retirement	143,000	178,000	105,000
Generic retirement	146,000	178,000	107,000
Least Favorable Economies for Construction			
W/o Load Management			
Utility announced retirement	150,000	223,000	60,000
Generic retirement	195,000	242,000	117,000
With Load Management			
Utility announced retirement	47,000	94,000	17,000
Generic retirement	82,000	122,000	41,000

*Rounded to the Nearest 1000 MW

(1) 1979 Industry Projection

(2) 1979 National Laboratory Survey

(3) 1981 Dames & Moore Forecast

TABLE II

The Unsited Base Needed by the Year 2000 to Support an All Pumped Storage Peaking Construction Program

	Projection I(1)	Projection II(2)	Dames & Moore Forecast(3)
Most Favorable Economies for Construction			
W/o Load Management			
Utility announced retirement	198,000	313,000	95,000
Generic retirement	227,000	340,000	116,000
With Load Management			
Utility announced retirement	189,000	302,000	89,000
Generic retirement	216,000	329,000	107,000
Least Favorable Economies for Construction			
W/o Load Management			
Utility announced retirement	82,000	186,000	9,000
Generic retirement	139,000	251,000	41,000
With Load Management			
Utility announced retirement	37,000	126,000	4,000
Generic retirement	106,000	232,000	19,000

*Rounded to the Nearest 1000 MW

(1)1979 Industry Projection

(2)1979 National Laboratory Survey

(3)1981 Dames & Moore Forecast

TABLE III

Maximum Estimated Installed Peaking Capacity by the Year 2000

(if no additional peaking capacity is added beyond that planned or currently under construction)

	Projection I(1)	Projection II(2)	Dames & Moore Forecast(3)
Most Favorable Economies for Construction			
W/o Load Management			
Utility announced retirement	24,000	42,000	11,000
Generic retirement	38,000	56,000	23,000
With Load Management			
Utility announced retirement	3,000	7,000	2,000
Generic retirement	8,000	19,000	6,000
Least Favorable Economies for Construction			
W/o Load Management			
Utility announced retirement	11,000	26,000	7,000
Generic retirement	26,000	42,000	15,000
With Load Management			
Utility announced retirement	2,000	4,000	2,000
Generic retirement	5,000	12,000	4,000

*Rounded to the Nearest 1000 MW

(1) 1979 Industry Projection

(2) 1979 National Laboratory Survey

(3) 1981 Dames & Moore Forecast

TABLE IV

The Unsited Base Needed by the Year 2000 to Support an All Non-Pumped Storage Peaking Construction Program

	Projection I[1]	Projection II[2]	Dames & Moore Forecast[3]
Most Favorable Economies for Construction			
W/o Load Management			
Utility announced retirement	196.000	340,000	570,000
Generic retirement	267,000	412,000	115,000
With Load Management			
Utility announced retirement	113,000	242,000	42,000
Generic retirement	182,000	315,000	60,000
Least Favorable Economies for Construction			
W/o Load Management			
Utility announced retirement	174,000	313,000	48,000
Generic retirement	240,000	393,000	99,000
With Load Management			
Utility announced retirement	99,000	229,000	32,000
Generic retirement	168,000	296,000	51,000

*Rounded to the Nearest 1000 MW

(1) 1979 Industry Projection

(2) 1979 National Laboratory Survey

(3) 1981 Dames & Moore Forecast

interregional transmission systems by which the hourly movement of electricity over long distances between most regions cannot be accomplished.

Table I summarizes at the national level the need for pumped storage capacity in megawatts (MW) that was computed for the various assumptions of load growth, load management, retirements, and the applicability of existing capacity as future peakers. In the first of these summary results, it was assumed that all peaking needs would be met by pumped storage construction. Table III summarizes, for the same assumptions, the use of alternatives to pumped storage; for this table all peaking needs are met by such peaking systems as gas turbines, combined cycle, or such new peaking technologies as fuel cells.

As can be seen from Table I, load forecast is the most significant factor in the determination of the need for peaking capacity, followed by implementation of load management (as an alternative to peaking capacity construction) and the question of favorable economic conditions for construction. Generic versus company announced retirements are the least significant. The differences between Tables I and III further illustrate the current competitive differences between adding pumped storage or building additional peakers. Table I generally implies that for the most favorable conditions for construction, an additional, large base-load construction program (with substantial long-run reduction in oil and gas consumption) would also be needed. Table III generally implies a much higher level of oil and gas consumption but a smaller base-load plant construction program. Under the least favorable economic conditions for construction, pumped storage is built only after all other existing oil and gas capacity is being used for peaking needs. The corresponding base-load construction programs are illustrated in Tables II (the base needed to support an all pumped storage program) and IV (the base needed to support a non-pumped storage, peaker construction program.

4. PUMPED STORAGE FACILITIES

In the first part of the project six existing and proposed sites were chosen as suitable case histories for review. The technical, environmental, and economic characteristics of these pumped storage plants were examined. The decisions that resulted in their construction were reviewed for relevance in similar future decisionmaking. The results of these studies are reported in Section 2; the sites were:

1. The Taum Sauk Project in Missouri, a Union Electric Company facility completed in 1963
2. The Northfield Mountain Project in Connecticut, a Northeast Utilities facility, operational in 1973
3. The Ludington Pumped Storage Project in Michigan, jointly owned by the Consumers Power Company and the Detroit Edison Company, operational in 1974
4. The Helms Pumped Storage Project near Fresno, California, currently under construction as part of the Pacific Gas and Electric Company
5. Blenheim-Gilboa Project, owned by the Power Authority of the State of New York (PASNY), operational in 1973
6. The proposed Breakabeen/Prattsville Pumped Storage Project, also a PASNY facility.

In addition to identifying existing projects, the literature was searched to identify sites for possible new facilities in the United States (this consisted of a review of the work of others). Figure 1 shows the general geological opportunities for underground pumped storage facilities. As the map indicates, the areas with the highest degree of confidence are located in the Pacific Northwest and Central Northern regions of the country. The Gulf and Atlantic coastal regions are the areas most unsuitable for underground pumped storage development. Figure 2 shows the number of and total generating capacity of all of the existing and proposed facilities in the United States. The histogram indicates pumped storage generation has been increasing consistently since 1965. Figure 3 indicates the general location of projected and operational pumped storage plants in the United States; as can be seen the majority of pumped storage facilities are located in the Appalachian mountain region although California has the largest number of pumped storage facilities of any one state. Project briefs and data sheets were developed on each existing and proposed project in the United States (see Appendix A).

The second part of this project considered alternative peaking technologies and compared them, on a comprehensive basis, to pumped storage. This task included identification of the most promising alternative technologies, both existing and new, and a time and total availability assessment for each. The study determined three significant alternative strategies to pumped storage:

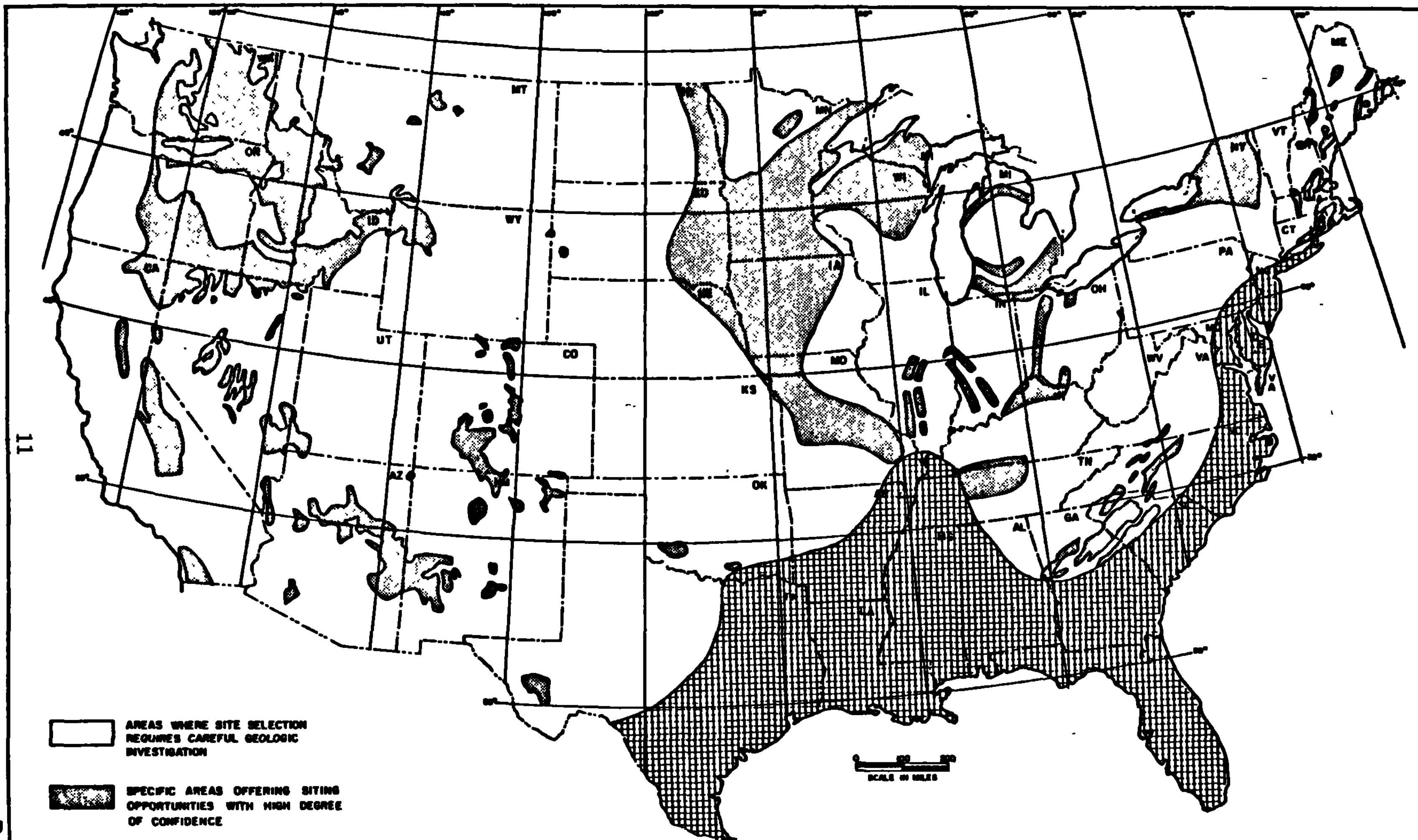


FIGURE 1
GEOLOGIC SITING OPPORTUNITIES - UHPS

SOURCE: Charles T Main, Inc., 1978.
(FROM ACRES AMERICAN STUDY 3 AND PUBLIC SERVICE ELECTRIC AND GAS STUDY 2, TABLE II-1)

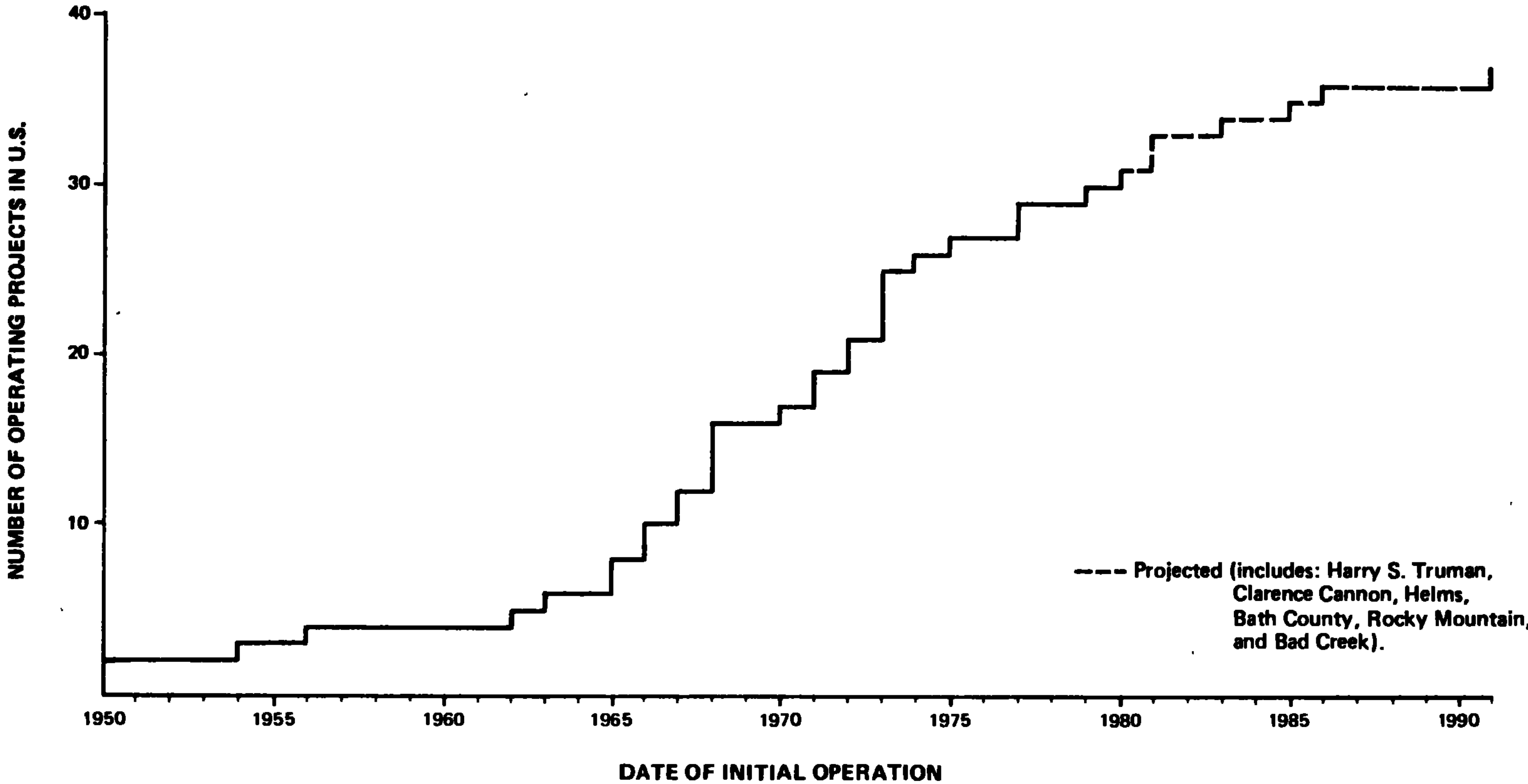


FIGURE 2
NUMBER OF OPERATING PROJECTS
HYDROELECTRIC PUMPED STORAGE PLANTS

FIGURE 3
LOCATION OF HYDROELECTRIC PUMPED STORAGE PLANTS

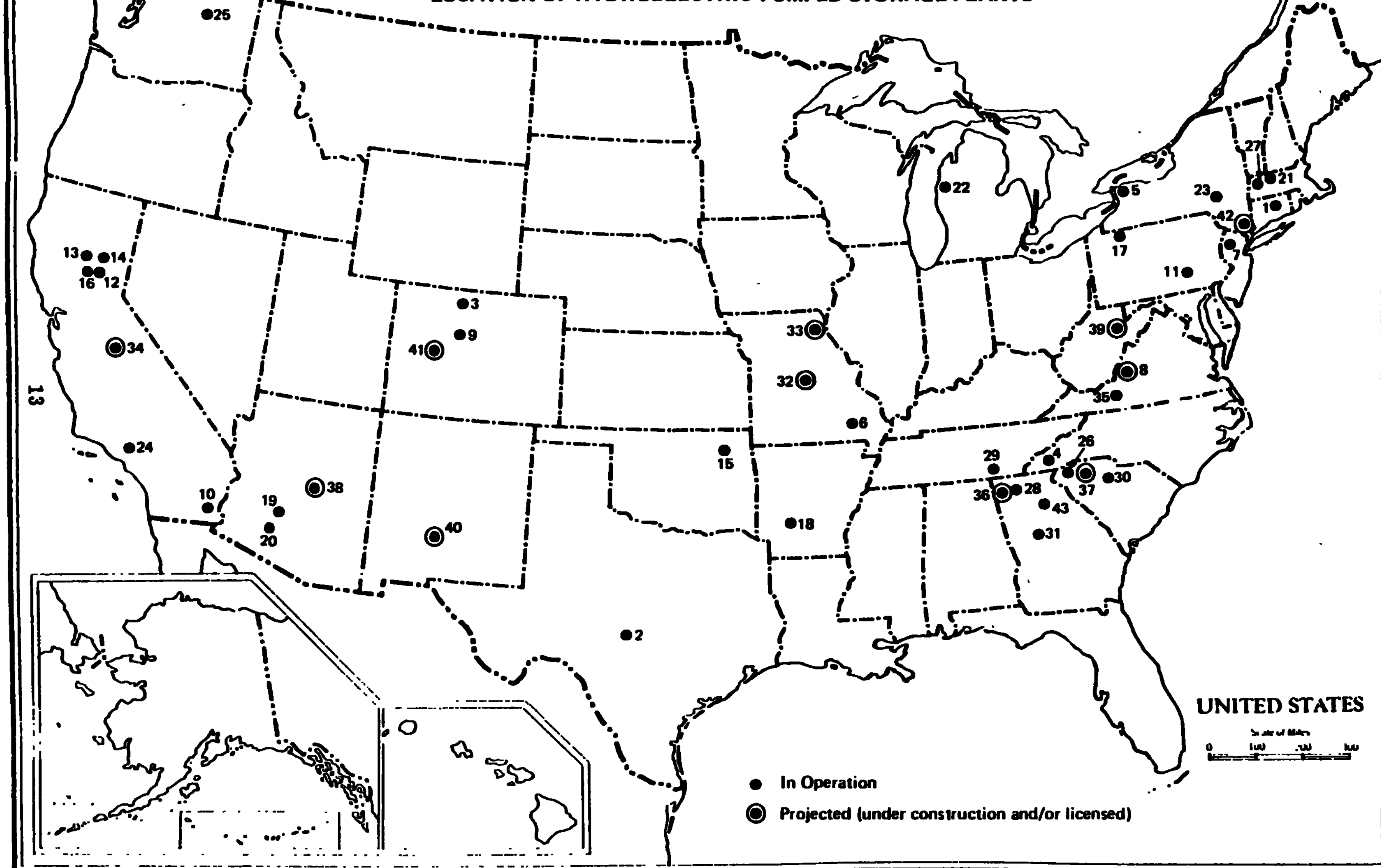


FIGURE 3 (cont'd)

Legend

Project Number	Project Name	State
1	Rocky River	Connecticut
2	Buchanan	Texas
3	Flatiron	Colorado
4	Hiwassee	N. Carolina
5	Lewiston	New York
6	Taum Sauk	Missouri
7	Yards Creek	New Jersey
8	Smith Mountain	Virginia
9	Cabin Creek	Colorado
10	Senator Wash	California
11	Muddy Run	Pennsylvania
12	O'Neill	California
13	Thermalito	California
14	Edward G. Hyatt	California
15	Salina	Oklahoma
16	San Luis	California
17	Kinzua	Pennsylvania
18	DeGray	Arkansas
19	Mormon Flat	Arizona
20	Horse Mesa	Arizona
21	Northfield Mountain	Massachusetts
22	Ludington	Michigan
23	Blenheim-Gilboa	New York
24	Castaic	California
25	Grand Coulee	Washington
26	Jocassee	S. Carolina
27	Bear Swamp	Massachusetts
28	Carters	Georgia
29	Raccoon Mountain	Tennessee
30	Fairfield	S. Carolina
31	Wallace	Georgia
32	Harry S. Truman	Missouri
33	Clarence Cannon	Missouri
34	Helms	California
35	Bath County	Virginia
36	Rocky Mountain	Georgia
37	Bad Creek	S. Carolina
38	Montezuma	Arizona
39	Davis	W. Virginia
40	Seboyeta	New Mexico
41	Mt. Elbert	Colorado
42	Cornwall	New York
43	Richard B. Russell	Georgia

- Part one of the first alternative was simply to consider meeting all peak loads using conventional generating technologies. These were defined as gas turbines and combined-cycle plants. Part two of this alternative was to widen the range and consider new peaking technologies (wind, solar, or fuel cells), including those for storing energy (batteries, compressed air, underground water storage).

- In lieu of constructing any new peakers, a utility might purchase devices and finance programs that would be used to shift peak loads (in time) into nighttime demand valleys. Thus the base-load plants that would otherwise service the pumped storage load, off-peak, could directly serve the shifted peak load. The effect of this strategy is to shift peak load, not to inhibit its growth.

- Financing projects to inhibit future growth (i.e., insulating) is an alternative to new peaking capacity construction or shifting peak loads.

A comprehensive list of conventional generating technologies was first developed. From this list, part-time energy producing technologies and base-load alternative technologies were deleted (e.g., geothermal). Table V is a summary of the costs for the most important of these remaining alternative technologies. Compared to alternative technologies, pumped storage has the broadest range of capital costs, while customer thermal storage and tidal power are at the extreme ends of the range. Table VI summarizes the specific regional applicability of these technologies. For the two most competitive peaking technologies, we computed lifetime revenue and annual minimum revenue requirements, which are shown in Tables VII and VIII. Revenue requirements for pumped storage are substantially below those of combined-cycle generation. However, the difference in the comparative costs of adding pumped storage as opposed to combined-cycle technology are insignificant. This comparison is presented in Table IX.

Pumped storage and its alternatives were assessed comparatively as to their potential impact in the areas of physical constraints, economic considerations, environmental issues, and institutional/regulatory constraints. Table X shows the results of the assessment. The issues of major concern to pumped storage development are the environmental and institutional/regulatory constraints.

TABLE V

Comparison of Cost Data

Technology	Capital cost ($/kW)	Operation and Maintenance Cost (¢/kWh)
Utility Thermal Storage	85-200	N/A
Compressed Air Storage	270-480	0.2
Advanced Storage Batteries	400-700	0.15-0.25
Combustion Turbines	215-250	0.3
First-Generation Fuel Cells	400-700	0.4-0.5
Hydroelectric	500-2,000	--
Solar Photovoltaic	1,100-1,800	0.1-0.3
Combined-Cycle	380-470	0.2-0.3
Coal Gasification/ Combined-Cycle	825-975	0.5
Atmospheric Fluidized Bed	700-900	0.8
Solar Thermal Power	1,700-2,000	0.4-0.6
Wind Power	800-1,000	0.1-0.3
Tidal Power	2,300-3,500	0.2
Wood-Fired Powerplant	1,300-1,700	.5-1.0
Customer Thermal Storage	75-150	N/A
Load Management	100-250	0.1
Pumped Storage	500-2,000	--

TABLE VI

Regional Availability of Alternative Supply Technologies*

Technology	Regional Availability	Reference**
Compressed Air	Available in all regions; potentially constrained by geology in portions of the East Coast, Southeast (especially Florida), Great Lakes, Southwest, and West Coast	Section 3.2.3.2 Table 3-2
Hydroelectric	Available in all regions; greatest potential in the Pacific Northwest, with substantial potential in the Northeast, West Virginia, Kentucky, Tennessee, Arkansas, and California	Section 3.2.3.6
Solar Photovoltaic	Available in all regions; best capacity factors in the Southwest	Section 3.2.3.7
Solar Thermal	Technically possible in all regions; due to need for direct insolation, initial deployment will be concentrated in the Southwest	Section 3.2.4.6
Wind	Technically possible in all regions; best wind resources in the Northeast, Appalachia, Great Plains States, and portions of California and Washington	Section 3.2.4.7
Tidal	Potential sites limited to Maine and Alaska	Section 3.2.4.8 Figure 3-4
Wood, Other Biomass	Available in all regions; most concentrated potential in North (West, Central, and East) and South Atlantic regions	Section 3.2.4.9

*Other Categories A and B supply technologies are, or will potentially be, available in all regions.

**See also Appendix B.

TABLE VII

Summary of Lifetime Revenue Requirements (Levelized)
(millions of dollars per year)

	Pumped Storage	Combined Cycle
Return on net investment	11	8
Economic depreciation	4	3
Income tax	1	1
Fuel, operation, maintenance	32	61
	48	73

TABLE VIII

Annual Minimum Revenue Requirements
(millions of dollars)

Year	Pumped Storage	Combined Cycle
1	39	52
2	46	59
5	47	66
15	44	67
25	40	65
35	37	63

TABLE IX

Comparative Costs of Adding Pumped Storage or Combined Cycle

Year	GWH x 10^3	Pumped Storage Carrying	Operation and Maintenance Coal	Coal for Pumped Storage	Combined Cycle Fuel	Combined Cycle Carrying	Pumped Storage $	Pumped Storage $/MWH	Combined Cycle $	Combined Cycle $/MWH
1	17.	1.2	661.0				666.2	38.95	661.0	38.88
2	17.5	3.6	677.4				681.0	38.91	677.4	38.71
3	18.	7.2	693.8				701.0	38.94	693.8	38.54
4	18.5	10.8	710.2				721.0	38.97	718.2	38.39
5	19.	14.4	726.6				741.0	39.00	726.6	38.24
6	19.5	16.8	743.0				759.8	38.96	743.0	38.10
7	20.	18.0	759.4			12.	777.4	38.87	771.4	38.57
8	20.5	18.0	764.4	20.8	40.5	12.	803.2	39.18	821.9	39.85
9	21.	18.0	769.4	20.8	40.5	12.	808.2	38.49	821.9	39.14
10	21.5	18.0	774.4	20.8	40.5	12.	813.2	37.82	826.9	38.46

PHYSICAL CONSTRAINTS

ALTERNATIVE	GEOLOGIC	TOPOGRAPHIC	SITING	TURN AROUND AND STARTING TIME	OPERATIONAL COMPLEXITY	MAINTAINABILITY	USEFUL LIFE	POTENTIAL FOR EXPANSION
PUMPED STORAGE	■	■	■	□	□	□	□	■
CONVENTIONAL HYDROELECTRIC	■	■	■	□	□	□	□	■
COMBUSTION TURBINES	□	□	□	◩	□	□	◩	□
COMBINED CYCLE	□	□	□	◩	◩	□	◩	□
OIL PLANT CONVERSION	□	□	□	◩	□	□	◩	◩
UTILITY THERMAL STORAGE	■	□	■	◩	□	◩	◩	◩
COMPRESSED AIR	■	□	■	◩	□	□	◩	◩
ADVANCED BATTERIES	□	□	□	□	□	◩	■	□
PHOSPHORIC ACID FUEL CELLS	□	□	□	◩	□	◩	◩	□
SOLAR PHOTOVOLTAIC	□	□	■	■	□	◩	◩	□
COAL GAS/COMBINED CYCLE	□	□	□	◩	◩	◩	◩	□
FLUIDIZED BED	□	□	□	■	◩	◩	◩	□
COGENERATION	□	□	◩	■	◩	□	◩	◩
SOLAR THERMAL	□	□	■	■	□	■	◩	◩
WIND	□	■	■	■	□	■	◩	□
TIDAL	□	■	■	■	◩	□	□	■
WOOD-FIRED	□	□	■	◩	□	◩	◩	◩

ECONOMIC CONSIDERATIONS

ALTERNATIVE	CAPITAL COSTS	O & M COSTS	FUEL SUPPLY COSTS	EFFICIENCY
PUMPED STORAGE	◩	□	■	◩
CONVENTIONAL HYDROELECTRIC	◩	□	□	□
COMBUSTION TURBINES	□	□	■	■
COMBINED CYCLE	◩	□	■	◩
OIL PLANT CONVERSION	◩	◩	◩	□
UTILITY THERMAL STORAGE	■	□	□	□
COMPRESSED AIR	□	□	◩	□
ADVANCED BATTERIES	◩	□	□	◩
PHOSPHORIC ACID FUEL CELLS	◩	◩	◩	◩
SOLAR PHOTOVOLTAIC	■	◩	□	■
COAL GAS/COMBINED CYCLE	■	■	◩	◩
FLUIDIZED BED	◩	■	□	◩
COGENERATION	■	◩	□	□
SOLAR THERMAL	■	◩	□	■
WIND	◩	◩	□	◩
TIDAL	■	◩	□	◩
WOOD-FIRED	■	■	◩	■

ENVIRONMENTAL ISSUES

ALTERNATIVE	LAND USE	TERRESTRIAL ECOLOGY	AESTHETICS	WATER QUALITY	AQUATIC/MARINE ECOLOGY	GEOLOGY AND SOILS	GROUNDWATER	AIR QUALITY	SOUND QUALITY	DEPLETION OF OIL OR NATURAL GAS
PUMPED STORAGE	■	■	■	■	■	◩	□	□	◩	◩
CONVENTIONAL HYDROELECTRIC	■	■	◩	■	■	◩	□	□	◩	□
COMBUSTION TURBINES	□	□	◩	◩	◩	□	□	■	◩	■
COMBINED CYCLE	□	□	◩	◩	◩	□	□	■	◩	■
OIL PLANT CONVERSION	◩	◩	□	◩	■	◩	□	■	◩	□
UTILITY THERMAL STORAGE	□	□	□	◩	◩	□	◩	□	□	◩
COMPRESSED AIR	◩	□	□	□	□	□	◩	◩	■	◩
ADVANCED BATTERIES	□	□	□	□	◩	□	◩	◩	□	◩
PHOSPHORIC ACID FUEL CELLS	□	□	□	□	□	□	□	◩	□	◩
SOLAR PHOTOVOLTAIC	◩	◩	◩	□	□	□	□	□	□	□
COAL GAS/COMBINED CYCLE	□	□	□	◩	◩	□	□	◩	◩	□
FLUIDIZED BED	□	□	□	◩	◩	□	□	◩	□	□
COGENERATION	□	□	□	◩	◩	□	□	◩	◩	◩
SOLAR THERMAL	◩	◩	◩	◩	◩	□	□	□	□	□
WIND	□	◩	◩	□	□	□	□	□	■	□
TIDAL	■	□	◩	■	■	◩	□	□	□	□
WOOD-FIRED	■	◩	□	■	■	◩	□	■	□	□

INSTITUTIONAL/REGULATORY CONSTRAINTS

ALTERNATIVE	NEPA	CLEAN AIR ACT	CLEAN WATER ACT	WATER RESOURCES PLANNING ACT	WILD AND SCENIC RIVERS ACT	FISH AND WILDLIFE COORDINATION ACT	STATE LAWS AND REGULATIONS	SAFETY AND HEALTH REGULATIONS	DEVELOPMENT, OWNERSHIP, FINANCE	COST AND BENEFIT
PUMPED STORAGE	■	□	■	■	■	■	■	◩	◩	■
CONVENTIONAL HYDROELECTRIC	■	□	■	■	■	■	■	◩	◩	■
COMBUSTION TURBINES	■	■	◩	◩	◩	□	◩	◩	□	□
COMBINED CYCLE	■	■	◩	◩	◩	□	◩	◩	□	□
OIL PLANT CONVERSION	■	■	◩	□	□	□	◩	◩	□	□
UTILITY THERMAL STORAGE	■	□	◩	◩	◩	□	◩	◩	□	□
COMPRESSED AIR	■	■	□	□	◩	□	◩	◩	□	□
ADVANCED BATTERIES	◩	◩	□	□	◩	□	◩	◩	□	□
PHOSPHORIC ACID FUEL CELLS	■	■	□	□	◩	□	◩	◩	□	□
SOLAR PHOTOVOLTAIC	◩	□	□	□	◩	□	◩	■	□	□
COAL GAS/COMBINED CYCLE	■	■	◩	◩	◩	□	◩	◩	□	□
FLUIDIZED BED	■	◩	◩	◩	◩	□	◩	◩	□	□
COGENERATION	◩	■	◩	◩	◩	□	◩	◩	□	□
SOLAR THERMAL	◩	□	◩	◩	◩	□	◩	◩	□	□
WIND	◩	□	□	□	◩	□	◩	◩	□	□
TIDAL	■	□	■	■	◩	□	◩	◩	□	□
WOOD-FIRED	■	■	◩	◩	◩	□	◩	◩	□	□

LEGEND
- □ NO CONCERN
- ◩ MODERATE CONCERN
- ■ MAJOR CONCERN

TABLE X

COMPARATIVE ASSESSMENT DF IMPACTS OF PUMPED STDRAGE AND ALTERNATIVES

Dames & Moore

5. REGIONAL ANALYSIS ON THE NEED FOR PUMPED STORAGE AND ITS ALTERNATIVES

The third part of this project was to forecast the demand for additional pumped storage over the next 20 years. As previously discussed, the basis of this assessment was the analysis of 17 regions of the country. Each is an actual electricity planning region that has been defined and identified by the electric utility industry. Each region annually publishes a forecast of demand for electric energy and plans for new generation to meet that demand. In addition each region estimates possible interregional transfers.

Because of the data intensive nature of the analysis and the regional limitations of a more generic analysis, a specially designed electric energy regional computer program was developed for use in these studies. The program, the Dames & Moore DISPATCH Model, is a detailed computer program that dispatches, on a regional basis, all known electricity generating units plus all powerplant additions planned or under construction in the region. The computer program is designed so that unavailable data or company plans not yet formalized for needed capacity in the post-1990 time frame, can be supplemented with additional base generation, pumped storage, or peaking capacity needed to meet the prescribed load. The country was initially separated into the 17 existing National Electric Reliability Council (NERC) regions and pools. Once the need for new base pumped storage and peaking capacity was calculated, the results were summarized and re-aggregated into the group of seven contiguous "fuel commonality" regions.

The DISPATCH model, designed particularly to access U.S. pumped storage potential, contains several assumptions that permit readily developed calculations, but which limit the model's ability to reflect the real world accurately. Load is dispatched according to an economic ordering of generation by fuel types, i.e., hydro is assumed to be the most economic generating fuel type and therefore all hydro is dispatched before all other fuel types. Ideally, load would be dispatched according to an economic ordering of each generating unit in the system.

The particular DISPATCH model used in this analysis is a deterministic rather than a probabilistic dispatch. Forced outages are assumed to occur at a given frequency. In a probabilistic dispatch, forced outages are probabilisticly determined. The effect of this assumption is a tendency for the model to overestimate the load for a base plant and to underestimate load for a peaking plant. Similarly, scheduled maintenance is only an approximation and could be improved upon with more detailed data.

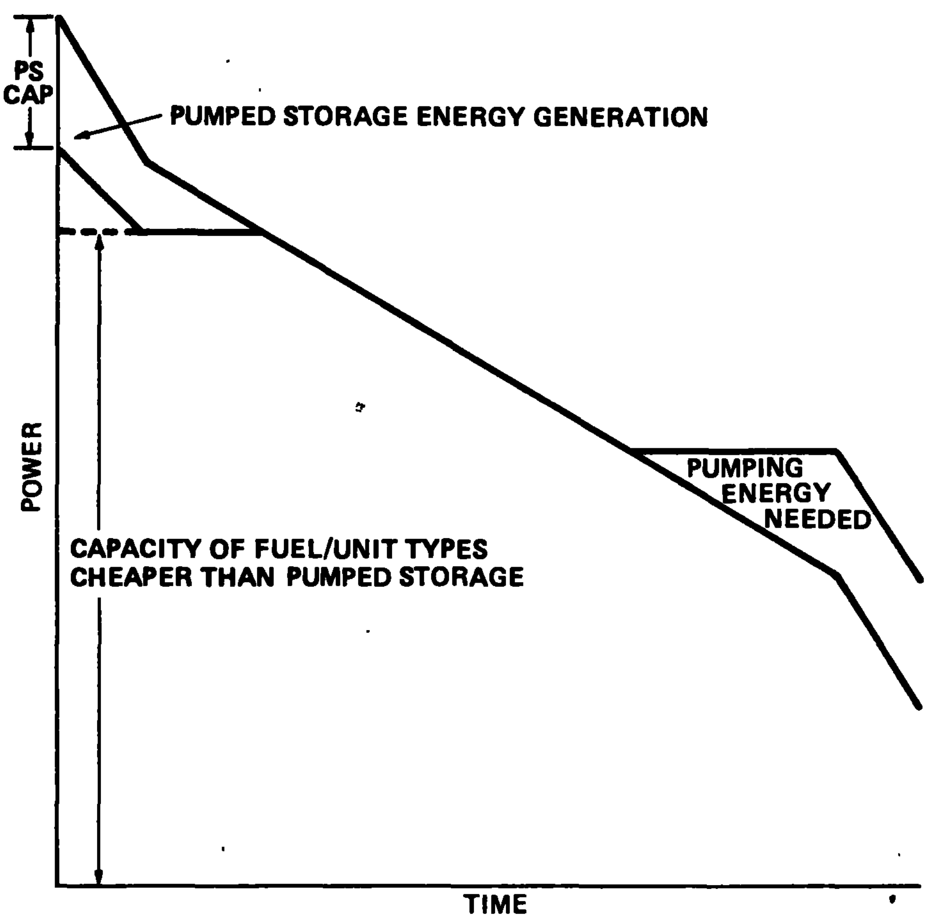
The last significant limitation of the DISPATCH model involves the load duration curve. A more accurate depiction of load would be an hour-by-hour load duration curve. By basing the dispatch on just one load duration curve, the uniqueness of each hour's load shape is lost.

Although the above limitations prevent a totally accurate depiction of the real world, the assumptions are no more limiting than those generally employed in any other model. The results produced by the DISPATCH model are reasonable, and no significant distortions of reality appear to have affected the results.

The computer program performed the analysis in the following manner. For each fuel commonality region, all generators in each of the powerplants are assigned forced outrage rates by fuel type and age, and then deterministically dispatched by category (such as run-of-the-river hydro, nuclear, coal, oil-steam, gas-steam, and the like) against their seasonal load duration curve. The calculations result in a year-by-year requirement for base and peak or base and pumped storage capacities. The results are presented in the regional reports in Section 5 for each 5-year interval.

The computer program was then implemented to assess the storage alternative (pumped storage, compressed air storage, electric batteries) and the peak capacity alternative for meeting peak load. Both storage and base capacity were calculated to meet loads for the storage alternative, and in this case base capacity had to include the additional need for base-load energy to power the storage load. For the peak capacity alternative, only base-load energy to power the base load was calculated. Since an efficiency difference exists in the base need between the total energy and the fuels used in each of the alternatives, the base capacities computed for each alternative differ. Figure 4 illustrates the base-load/peak energy dispatched against a typical load duration curve for pumped storage.

For both alternatives, an important economic distinction was represented by the selection of fuel sources to power base and peakers. If it is assumed, for example, in New England that oil is used to power future pumped storage and pumped storage is dispatched last as a peaker, then the long-term demand for additional pumped storage is far smaller than if nuclear or coal is used as the last base fuel and pumped storage is dispatched as the first peaking technology. On the



PSCAP = MAXIMUM PUMPED STORAGE CAPACITY

FIGURE 4

PUMPED STORAGE

other hand, if it is assumed that coal or nuclear will be used to power the peakers and that they are dispatched before oil or gas, then the demand for new base and pumped storage would be maximized for each of the other parameters.

The use of dispatch acts as a proxy for the "least favorable" and the "most favorable" economic conditions for construction shown earlier in Tables I thru IV. If it is economical in the long run to build pumped storage in New England instead of burning oil (i.e., the most favorable economics for construction), this means that the cost of money for new construction is low enough for the capital cost of new construction to be outweighed by the long-run costs of fuel oil used in a base-load plant. In terms of national economics it means that inflation is low and that oil has become scarce and expensive, or that oil (or gas) has been displaced by coal conversion and is no longer available for powering base-load or peaking capacity.

Table XI describes all scenarios studied in the assessment. The scenarios vary in their load growth, retirement schedule, and order of dispatch. For example, one scenario might examine the pumped storage capacity alternative under the Dames & Moore demand forecasts. No load management techniques are assumed to be employed (base-load curve). The retirement schedule reflects those retirements announced by the utilities to NERC. Finally, the dispatch order of pumped storage would follow after all other fuel types. Another scenario might examine alternative peaking capacity under the Projection II demand forecast, using the generic retirement schedule based on the age of the generating unit. Load management techniques may be assumed to be employed. The dispatch order of the alternative peaking capacity technology may follow after coal steam. The summary results for the most likely set of parameters (described in the first example) are shown in Table XII. These results indicate the maximum amount of pumped storage capacity achievable under the most likely scenario of assumptions. The growth rates of projected demand for each of the 17 pools used to calculate the results in Table XII are presented in Table XIII. Tables I thru IV, previously discussed, summarize the national results. The regional results for each set of assumptions considered in the assessment are to be found in Section 5 of the report.

For all conditions considered a regional pattern of demand emerged for pumped storage or its alternative pure peaking. Most of the pumped storage is needed where excess base already exists but for which there are emerging shortages of peaking capacity. This situation exists throughout the north and

TABLE XI

Scenarios

Pumped storage capacity and alternative capacity technologies were forecast under each of the three demand projections (Projection II, Median, and Dames & Moore) for each of the supply conditions below.

I. Base-Load Shape

   A. Utility-Announced Retirements Schedule
      1. After coal steam
      2. After oil steam
      3. After all other fuel types

   B. Generic Retirement Schedule
      1. After coal steam
      2. After oil steam
      3. After all other fuel types

II. Load Management Techniques

   A. Utility-Announced Retirement Schedule
      1. After coal steam
      2. After oil steam
      3. After all other fuel types

   B. Generic Retirement Schedule
      1. After coal steam
      2. After oil steam
      3. After all other fuel types

TABLE XII

Maximum Pumped Storage Development by Region Under Most Likely Scenario

	Maximum Pumped Storage Capacity
Continental United States	59,875 MW[1]
New England; New York; Mid-Atlantic (NEPOOL-NYPP-MAAC)	3,353
Florida	5,254
Southern; Tennessee Valley; Virginia-Carolinas (Southern-TVA-VACAR)	13,399
East Central; Mid-America; Mid-Continent (ECAR-MAIN-MARCA)	35,981
Southwest; Electric Reliability Council of Texas (SPP-ERCOT)	1,314
Rocky Mountains; Northwest (RMPA-NWPP)	0
Arizona-New Mexico; Southern California-Nevada; Northern California-Nevada (AZNM-SCNV-NCNV)	574

[1]Based on Dames & Moore's load growth projections, utility-announced retirement schedule, dispatch of pumped storage after all other fuel types, and no additional load management techniques implemented.

TABLE XIII

Hydroelectric Pumped Storage Analysis Projections of Energy Demand Growth

Dames & Moore Projection

NERC Region*	1978-1985	1985-1990	1990-1995	1995-2000
NEPOOL	1%	1%	1%	1%
NYPP	1	1	1	1
MAAC	2	2	2	1
Florida	4	3	3	3
Southern	2	2	2	2
TVA	3	3	2	1
VACAR	4	4	3	2
ECAR	2	3	2	2
MAIN	3	4	3	3
MARCA	4	4	3	3
SPP	4	3	3	2
ERCOT	4	3	3	2
RMPA	5	4	3	3
NWPP	3	3	2	2
AZNM	5	4	3	3
SCNV	2	2	1.5	1.5
NCNV	2	2	1.5	1.5

*NEPOOL = New England; NYPP = New York; MAAC = Mid-Atlantic Area; Florida; South Central; TVA = Tennessee Valley Authority; VACAR = Virginia-The Carolinas; ECAR = East Central; MAIN = Mid-Atlantic; MARCA = Mid-Continent; SPP = Southwest; ERCOT = Texas; RMPA = Rocky Mountains; NWPP = Northwest; AZNM = Arizona-New Mexico; SCNV = Southern California-Nevada; NCNV = Northern California-Nevada.

middle parts of the country where for years coal has dominated. In contrast, no pumped storage is ever needed where large hydro systems are already in place. As growth occurs in these areas, the existing water storage on the hydro systems allows hydro to act as a pure peaker, and only base plants are needed for these systems. This situation exists throughout the Northwest and Rocky Mountain areas. Though there may be isolated areas in the Northwest and Rocky Mountain regions where the transmission system cannot make the regional base and peak energy available to the specific area, in general, the areas have no need for pumped storage.

In the areas where the need for pumped storage is most variable as a consequence of changing economic conditions, significant quantities of oil and/or gas are already being used. If these fuels continue to increase in cost (ahead of inflation) but construction costs do not escalate, pumped storage will develop more quickly. However, if oil and gas cease to escalate with construction costs, then there will be little need for increased pumped storage capacities. The base oil and gas generation capacity will, over time, shift to peaking use, as more appropriate base is added later. The most important point for these areas is that if gas and oil prices do not further escalate, then only new base-load plants will be added because the existing base gas and oil plants can operate economically as the new peakers. The present trend of economic development points to this course.

1.0 INTRODUCTION

"An Assessment of Hydroelectric Pumped Storage" is part of an overall study undertaken by the Corps of Engineers to assess the potential contribution of hydroelectric power resources to the Nation's energy supply. The objective of this report was to "prepare a comparative assessment of pumped storage with other alternatives for meeting peak electric power demands, and to develop estimates of the amount of pumped storage capacity that may be developed over the next 20 years." To accomplish this objective, the current state of pumped storage development for the United States was examined and the rationale for existing and possible future pumped storage development was identified.

Specifically, the reasons behind the decision to build a pumped storage facility as opposed to using alternative forms of peaking capacity were identified for several typical pumped storage facilities already on line in the United States. Alternative forms of peaking capacity were identified and compared to the beneficial and adverse impacts of pumped storage development. Regulatory, environmental, physical, and geological constraints were examined in great detail to assess the potential development of each type of capacity generator. The future potential for pumped storage capacity and alternative capacity development was estimated for seven composite regions of the United States, and estimates were developed under various scenarios in order to assess the likelihood of development. A brief summary of the major results of the report is presented below.

The future development of pumped storage systems will be affected by the need to add new generating capacity and by the overall competitiveness of alternatives to pumped storage. Major economic, physical, and environmental factors will affect the future development of pumped storage facilities. Conventional pumped storage systems need topographic conditions that provide a suitable potential head between upper and lower reservoirs. Also, geologic conditions are particularly important for underground pumped storage systems, and consequently, the siting of alternatives near demand centers may be more feasible than pumped storage facilities. Pumped storage, however, has a clear advantage over other alternatives and their physical constraints in terms of turnaround and starting times, operational complexity, maintainability, and useful life. The only physical disadvantage to pumped storage may be the complexity of expanding the facility if expansion is not included in the original design.

Among the economic factors favoring pumped storage is that of a well-known technology: There is virtually no risk that the project will be unable to operate substantially as designed. However, one economic disadvantage is the long construction time of pumped storage facilities in comparison to its alternatives. In addition, the extremely tight financial markets at present make it difficult for utilities to obtain the capital funds necessary to undertake any major construction projects.

Since pumped storage uses relatively large land areas in comparison to other alternatives, its potential effects on the environment (land use, terrestrial ecology, aesthetics) are great, although the use of existing reservoirs or lakes as part of the pumped storage system is likely to lessen these effects to some degree. Water quality and aquatic ecology effects are also potentially significant, but again, existing conditions will dictate the magnitude. In total, underground pumped storage systems have significantly fewer environmental impacts than conventional systems.

Environmental regulations probably have the most significant effect on siting powerplants. The major regulatory difference between pumped storage and the alternatives is the negligible impact of air quality regulations and the significant impacts of water and land resource regulations.

Alternatives to hydroelectric pumped storage are highly dependent on the status and availability of new technology. These new technologies can be divided into supply alternatives and demand alternatives. Supply alternatives are storage and power generating technologies that a utility can use to meet peak loads. Demand alternatives refer to rate restructuring, load management, conservation, and end-user technologies.

Overall, combustion turbines and hydroelectric power will continue to be the major supply alternative options for new peak-load power generation over the next two decades. If substantial reductions in capital cost can be achieved, fuel cells have the potential to become a viable alternative to diesels and combustion turbines in the 1990's. Photovoltaic energy conversion is likely to be limited to a minor supplemental role between now and the year 2000.

Existing oil- and coal-fired units will continue to be used for intermediate-load power generation. Hydroelectric power will continue to be a major option for new intermediate-load capacity as well as peak load. Combined-cycle units are ideally suited to intermediate-load operation, but new orders may be constrained by limitations imposed by the Fuel Use Act. Coal gasification/combined-cycle and fluidized bed combustion units could be commercially available in the early 1990's. Other technologies, such as cogeneration, solar thermal electric plants, wind turbines, and biomass plants, will also provide some additional capacity.

The demand alternatives fall into three categories: (1) thermal storage, (2) load management, and (3) conservation. The storage of heat by residential or commercial customers in either water or solid matter is technically simple and is limited only by economic considerations. Storage of coldness is uncommon and more complex, since large volumes are needed to store coldness on an annual basis, making this type of storage far less economical than heat storage.

Load management falls under two general approaches. In the first, the utility provides the customer with an economic incentive to manage his own load. In the second, the utility manages the customer's load through load control and communication devices. Generally, the utility controlled-load customer receives a lower rate for electricity. However, projections by the Edison Electric Institute (EEI) indicate generating cost savings of only about 1 percent.

Conservation results in an overall reduction in the quantity of energy used. Only two areas of conservation show significant savings in the residential area: setbacks and setups of thermostats and improved efficiency of household appliances. The EEI study projects industrial use of electricity savings of 20 percent and in the commercial sector a savings of approximately 45 percent from conservation techniques.

Various scenarios, consisting of different run conditions, were used to determine the future development of pumped storage capacity and alternative capacity technologies. Briefly, the potential for pumped storage capacity development was assessed under three load growth forecasts. Existing plant capacity was retired under two separate schedules: utility-announced retirements, as reported by the National Electric Reliability Council (NERC), and generic retirements based strictly on the age of a generating unit. Various dispatch orders for pumped storage were used and the effects assessed. In addition, the effects of load management on future pumped storage capacity development were examined. The same scenarios were used to assess the future development of alternative peaking technologies.

The combination of the most likely conditions results in an estimate of pumped storage capacity development for the continental United States of 59,875 megawatts (MW) by the year 1999. This estimate does not consider the environmental, physical, and geographical factors affecting pumped storage capacity development. Unsited base capacity development needed in conjunction with pumped storage capacity development is estimated at 8,478 MW, in 1999. Estimates were developed for seven composite regions of the United States, and under all of the scenarios developed, the ECAR-MAIN-MARCA region was estimated to have the greatest potential for pumped storage capacity development, followed by the Southern-TVA-VACAR composite region. The RMPA-NWPP composite region was estimated to have no potential for pumped storage development. The analysis will show that for even the minimum future peaking capacity requirements forecast herein, sufficient capacity to meet projected demands will be available only when substantial further additions of conventional pumped storage or of gas- or oil-fired turbines are developed.

In the report, Section 2.0 presents five pumped storage facilities now in existence in the United States and a brief discussion of their development. Section 3.0 examines alternatives to hydroelectric pumped storage, and Section 4.0 presents an assessment of hydroelectric pumped storage including constraints to its development. Section 5.0 provides estimates of the potential for future pumped storage capacity development on a regional basis, and the development of alternative technologies to meet pumped storage also is estimated.

2.0 THE HISTORY OF HYDROELECTRIC PUMPED STORAGE

2.1 Introduction

The following pages contain a brief description of pumped storage, followed by a chronological history of pumped storage in the United States. This section will be followed by six case studies of pumped storage projects, and finally by a summary which will draw on the entire chapter to document the advances in concepts and technology which have been (and will be) important to pumped storage development.

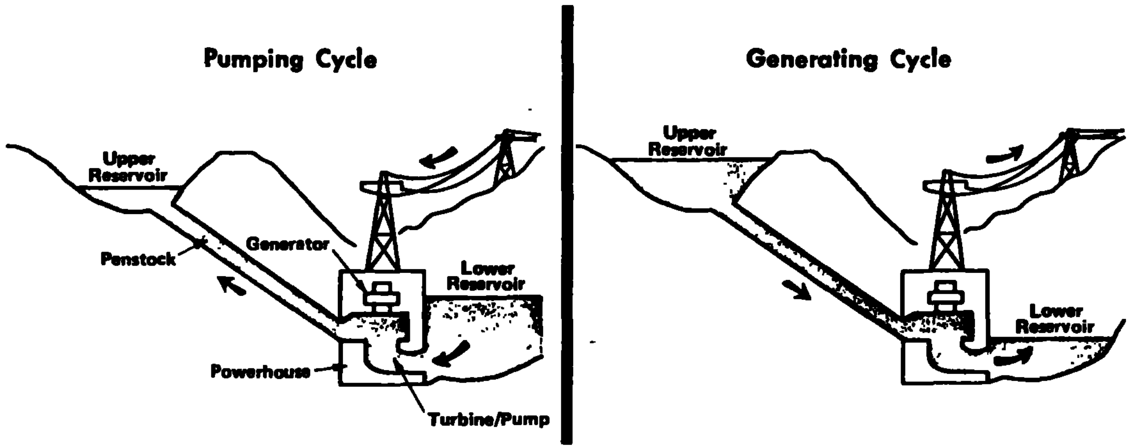
2.1.1 Definition of Hydroelectric Pumped Storage

A pumped storage project is a hydroelectric development that generates electric energy by using water that previously has been pumped from a lower reservoir to an upper reservoir. There are two principal categories of pumped storage projects:

- Pure developments produce power only from water that has been previously pumped to an upper reservoir.
- Combined developments utilize both pumped water and natural streamflow to produce power.

In a pure pumped storage development the upper reservoir is located off-stream while in a combined development the upper reservoir is located on a stream. In the latter case electricity may be generated without the pumping requirement as in a conventional hydroelectric facility. In either type of development the lower reservoir may be located either on-stream or off-stream. Figure 2-1 is a simplified illustration of a pure pumped storage arrangement.

Within the last 12 years the concept of underground pumped storage has received serious consideration. In an underground pumped storage arrangement the lower reservoir would be located below ground up to 4,000 feet below the surface reservoir. Use of both manmade and natural cavities for the lower storage reservoir has been studied. The powerhouse would also be constructed below grade maximizing head above the turbines. Figure 2-2 is an illustration of two possible underground pumped storage arrangements. Although underground pumped storage facilities have been shown in theory to be economically feasible, (Main, 1978) no



DURING LIGHT POWER LOAD

DURING PEAK POWER LOAD

FIGURE 2-1
OPERATION OF A PUMPED STORAGE PLANT

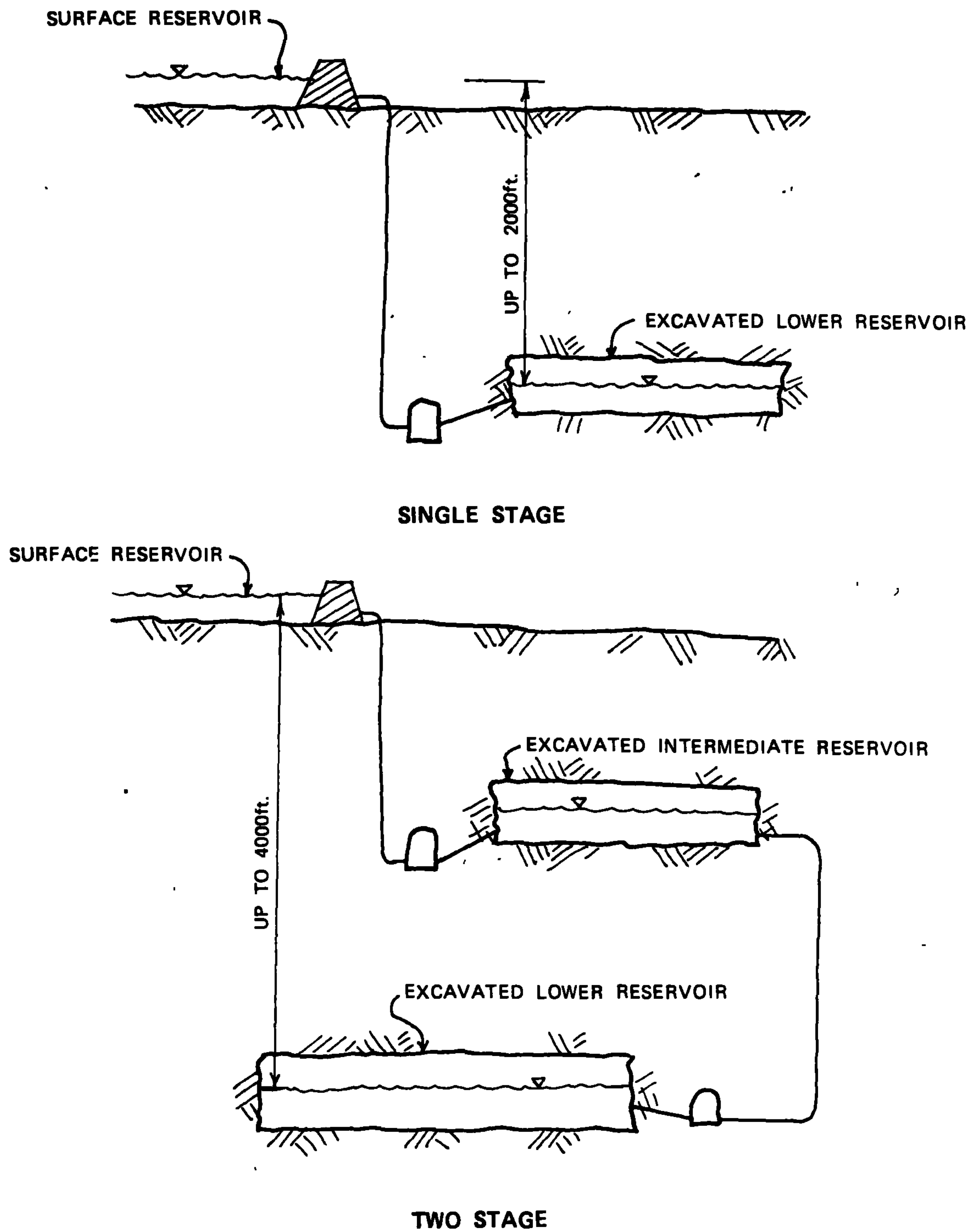


FIGURE 2-2
POTENTIAL UNDERGROUND PUMPED STORAGE ARRANGEMENTS
(not to scale)

such facilities have been constructed in the United States nor are any under serious consideration for Federal Energy Regulatory Commission (FERC) licensing.

More recently, the concept of combining underground hydro pumped storage facilities with compressed air storage systems has been reviewed (EPRI, 1976). In such a scheme the underground hydro reservoir also serves as the air storage reservoir. As water enters the lower reservoir during peak demand generating hours the increasing water level acts to provide constant pressure on the compressed air which is simultaneously being withdrawn to combustion turbines that are also responding to peak demands. In theory, advantages of this system include the support of two peaking power systems with the same underground reservoir and the provision of constant pressure on the compressed air storage reservoir without additional energy requirements. The economic and operational feasibility of such systems are unproven at present, and, as a result, the remainder of this chapter will focus on the history of pure and combined pumped storage development.

2.1.2 Objectives of Hydroelectric Pumped Storage

Although the objectives of pumped storage facilities have changed over the last 50 years, the common purpose of almost all such plants is to store energy for use during peak demand periods when generally larger base-load electric generating plants are inadequate or inefficient.

Figure 2-3 is a diagram of a typical weekly electric load curve and illustrates the portions of the demand which are satisfied by various generating facilities of a utility. Pumped storage plants are best utilized to meet the peak demands which occur daily since their quick-response and easily regulated output capability cannot be matched by larger fossil-fueled or nuclear plants. Note that the pumping energy for the Pumped storage plant is obtained during off-peak hours which also alllows the base load fossil-fueled and nuclear plants to operate at a more level output and therefore more efficiently. As a result, even though pumped storage plants operate at an overall cycle efficiency between .66 and .78, they are economical to construct and operate due to the increased efficiency of the entire, integrated electric generating system of a utility. In addition, they may at the same time allow postponing construction of new, costly base load plants.

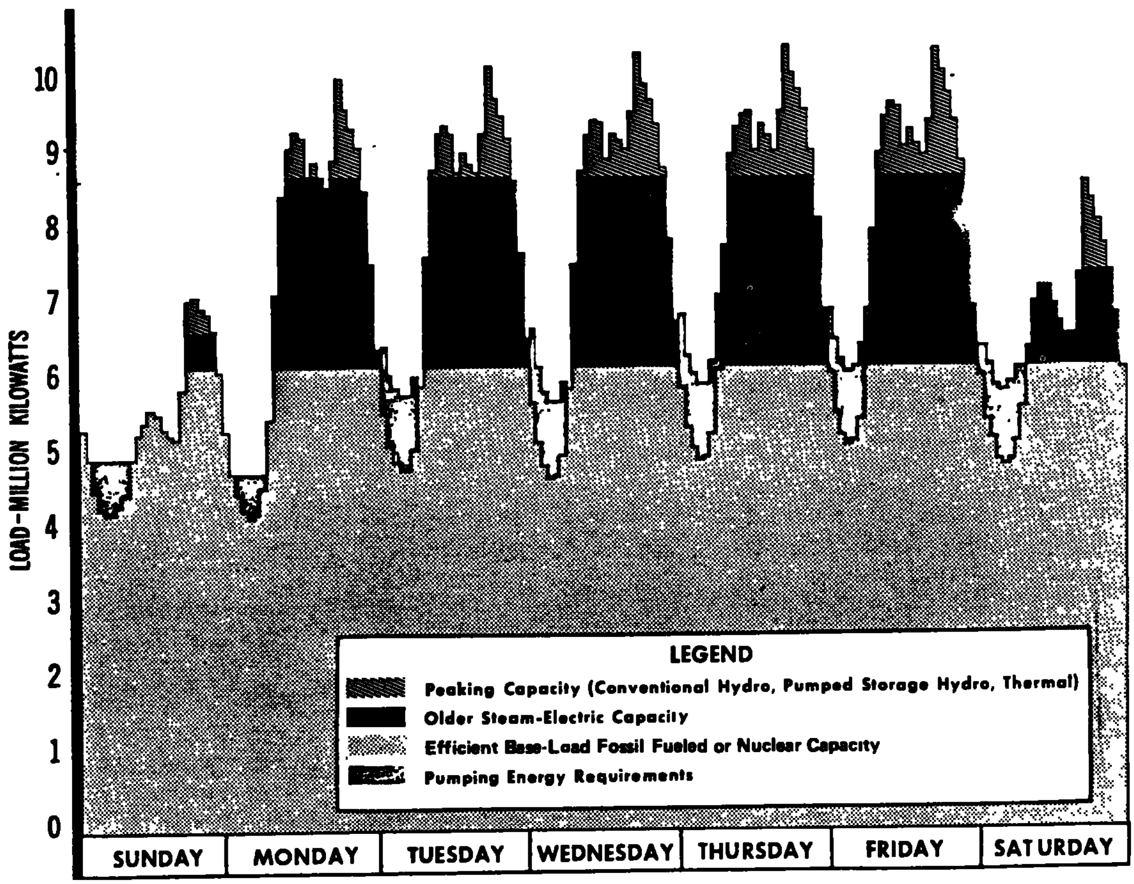


FIGURE 2-3
TYPICAL WEEKLY LOAD CURVE

Other objectives which have been documented during the development of pumped storage in the United States include:

- Provision of emergency power
- Increase in system reliability
- Voltage regulation capability
- Increase in system efficiency
- Fuel selection capability
- Multiple use of storage reservoirs including recreation, water supply, low-flow augmentation, flood control and irrigation
- Seasonal storage of hydroelectric energy.

These objectives, which in most instances are also advantages of pumped storage over other forms of peaking capacity, are listed here to provide a background for the following history of pumped storage development. They will be discussed in more detail later in this chapter.

2.2 History of Pumped Storage

Pumped storage had its beginning in Germany where the first plant was constructed in 1908. Most of the early developments were in western Europe, principally in Germany, Switzerland, and Italy. In the United States only four small developments had been constructed by 1960. Rocky River was the first pumped storage project constructed in the United States. It is on the Housatonic River in Connecticut and was constructed by the Connecticut Light and Power Company to provide seasonal storage for the existing 31-MW combined hydroelectric plant which contains one 24-MW conventional unit, two 3.5-MW motor generator units, and two pumps. Initial operation of the plant was in 1929.

Twenty years after the Rocky River Plant the Lower Colorado River Authority's Buchanan Project on the Colorado River in Texas became the second pumped storage installation in the United States. It has a separate pump and an 11-MW unit and although it is not now used for pumping on a regular basis, it has 23 MW of conventional hydro capacity still in operation. The early pumped storage projects such as Rocky River and the Buchanan Project had conventional hydroelectric generating units and separate pumps. The reversible pump/turbine, developed overseas in the 1940's and now used almost exclusively, greatly extended the field of pumped storage application at economical costs (See Section 2.4.1). Although reversible pump/turbines were tested and installed outside the United States, it was not until the 1950's that they were utilized in this country.

Soon after the Buchanan Project was built commitments for three additional projects were made: the Flatiron Project, the Hiwassee Plant, and the Lewiston development. The combined Flatiron Project was part of the Water and Power Resources Services' (formerly U.S. Bureau of Reclamation) Colorado-Big Thompson Project. The power and pumping plant contains two 31.5-MW conventional units and one 8.5-MW reversible unit, the first unit of that type installed in the United States. The pump/turbine unit pumps water into Carter Lake for irrigation in an area north of Denver. The Tennessee Valley Authority's (TVA's) Hiwassee Plant on the Hiwassee River in North Carolina, installed two years after Flatiron, contains a 60-MW reversible pump/turbine unit. It was used principally for pumping during winter months when Hiwassee Lake is drawn down to provide flood control storage capacity.

The 12-unit, 240-MW Lewiston development is specifically related to the conditions in the international treaty that governs flows over Niagara Falls. The treaty establishes minimum daytime flows over the falls of 100,000 cfs during the tourist season and minimum flows of 50,000 cfs at all other times. Flows in excess of these rates are divided equally between the United States and Canada and are available for generation of electric power. As a result, during the tourist season the greater portion of the water for power generation is available during offpeak periods at night when it is least needed. To take advantage of this, surplus nighttime flows are stored by pumping the water approximately 100 feet into Lewiston Reservoir for subsequent release through the Lewiston plant and then through 310 feet of head at the associated conventional Robert Moses Niagara powerplant which contains 13 150-MW units. The combined installation of 2,190 MW is substantially greater than the capacity that could have been provided without the pumping feature.

In addition to the development of the reversible Francis turbine, there are other reasons for the surge in pumped storage development in the 1950's as evidenced by the above projects. The post-war population increase and national economic growth reshaped the electric demand pattern by increasing the peak-to-base-load ratio and creating more distinct seasonal peaks for electricity. In addition, pumped storage became increasingly attractive as part of multi-purpose projects that enhanced the economics of each objective.

The planning and construction of pumped storage projects in the United States were greatly accelerated in the 1960's and early 1970's. Again there were important reasons for the increased interest. Average electric power loads in the United States were continuing their long-time growth rate of doubling approximately every 10 years. This presented an increasing challenge to the electric utility industry to plan and construct sufficient generating capacity to supply the electric loads in an efficient and reliable manner. Thus, there was a need and a market for new sources of power supply that could be operated economically in large electric power systems.

For many decades the nation's electric power supply had come principally from conventional steam-electric and hydroelectric generating stations, with hydroelectric power gradually becoming a smaller portion of the total supply. During that time, substantial advances were made in the efficiency of steam-electric units, and the normal role of such units was to operate initially to serve the base of the load and to gradually operate at lower capacity factors as new, larger, and more efficient units were installed. By the 1960's, however, most new steam-electric capacity was being provided in very large-capacity, high-temperature, high-pressure units, and there was little prospect for further significant improvements in efficiency. Those units, and the large nuclear-powered units that were being planned for installation throughout the country, are best suited for high capacity factor operation throughout their service lives. The ability to operate such units at or near rated capacity for long periods reduces the magnitude and frequency of thermally induced mechanical stresses in the steam units. There is, therefore, a reduction in forced outages and maintenance costs, and an improvement in system reliability; also, the operating efficiency of the units is improved significantly. Under these conditions there was a need for specially designed peaking capacity to complement the base-load power derived from conventional and nuclear steam-electric stations. Pumped storage plants were ideal for filling that need.

The Taum Sauk pumped storage plant, built by Union Electric Company in Missouri and first operational in 1963, marked a major landmark in turbine technology while fulfilling the above mentioned role in a utility system. The 764 feet of head under which the turbines operate was a major increase over previous designs and the 408 MW of reversible capacity in only two units put it in the class of large generators previously restricted to thermal turbo-generator plants. (See Case Study--Taum Sauk Pumped Storage Project).

Advances were also occurring in Europe with respect to increased operational heads. In 1959 at Festiniogg in Wales a 300-MW plant with a head of over 1000 feet was being planned as was the 400-MW Cruachan Plant in North Scotland with nearly 1,300 feet of head. These were followed closely in the United States by the Public Service Company of Colorado's Cabin Creek Plant, a pure pumped storage development with two units of 150 MW and a gross static head of 1,199 feet, which is the highest of any pumped storage plant now operating in the United States. At the same time the Japanese were joining the ranks of United States turbine manufacturers and were building projects with even higher heads. The Nuppamara and Ohira Projects with heads of 1,560 and 1,780 feet, respectively, surpassed previous records for operating heads.

The advances in turbine design that allowed such increases were significant since power output is directly proportional to the head under which the turbines operate. The ability to operate at higher heads not only increases plant capacity but reduces average development cost per kilowatt of output since increased costs due to more lengthy penstocks are a relatively small percentage of total project costs. This progress thus justified plants that at lower heads could not have been run economically compared to other options for peaking power.

The Muddy Run Project, an 8-unit, 800-MW pumped storage facility of the Philadelphia Electric Company, illustrates another aspect of pumped storage facilities. At the time of its initial operation in 1967, it was the largest pumped storage project in the United States. The plant is on the east bank of the Susquehanna River in Pennsylvania, about 12 miles upstream from Conowingo Dam. The Conowingo Reservoir serves as the lower reservoir and is the principal source of water for the upper reservoir. With such plants commonly located in undeveloped areas with topographical relief, the creation of two reservoirs usually offers unique opportunities for recreational development in conjunction with the hydroelectric capacity. Although reservoir drawdown and filling can cause significant fluctuations in water levels, such changes for reservoirs located on streams may be relatively slow and often total only a small percentage of total reservoir depth. As a result, development of picnicing, boating, fishing, and hiking facilities has gone hand-in-hand with development of pumped storage projects.

Federal Power Commission (now FERC) license agreements require plans for recreational development and often recommend studies of fishery development and/or impacts to be performed as part of the annual reports on project operation.

While many projects have required construction of new reservoirs, the use of natural bodies of water or existing reservoirs has always been advantageous to pumped storage developers. The use of existing reservoirs was not only encouraged by the savings in construction costs, but, as pumped storage moved into the late 1960's and 1970's, the environmental advantages of existing reservoirs became more important. With the environmental awareness of this period, best illustrated by the passage of the National Environmental Policy Act of 1969, the tendency to utilize existing reservoirs was emphasized. For example, the Pennsylvania Electric Company and Cleveland Electric Illuminating Company have, since 1970, jointly operated the Kinzua pumped storage project utilizing the Corps of Engineers' Allegheny Reservoir on the Allegheny River in western Pennsylvania as the lower reservoir while a 106-acre offstream reservoir above the left abutment of the Corps' dam serves as the upper reservoir. It is also significant to note that the project was conceived so that the lower reservoir at Kinzua could also serve to augment downstream flows during low flow periods. This has become a significant contribution of many pumped storage (as well as conventional hydro) projects.

Other pumped storage projects that use existing reservoirs or are integrated with facilities developed with other objectives (i.e., water supply, flood control) include:

- The conventional Mormon Flat and Horse Mesa hydroelectric projects on the Salt River in Arizona, which were expanded and modified during the early 1970's to include a reversible pumped storage unit in each plant

- The Castaic pumped storage development, completed in 1973 at the southern terminal of the California Aqueduct Project, which includes Pyramid Dam and the 179,000 acre-foot Pyramid Lake, the Angeles Tunnel and steel penstock, six 212.5-MW reversible pump/turbine units, one 56-MW conventional unit, and the 30,000 acre-foot Elderberry Reservoir that serves as the lower reservoir

- The six generating units (the completed installation will comprise 12 units) installed at the Water and Power Resources Service's Grand

Coulee Pumping Plant on the Columbia River in Washington, which were to serve initial irrigation development on the Columbia Basin Project

The Jocassee pumped storage plant, part of Duke Power Company's Keowee-Toxaway development on tributaries of the Savannah River in North and South Carolina, which uses Jocassee Reservoir and Lake Keowee for its pumping needs.

The early 1970's was a notable period in the history of pumped storage for several reasons. First, during this period the installed capacity of all pumped storage plants nationwide jumped tremendously primarily due to the startup of three large facilities: Northfield Mountain (1972), Ludington (1973), and Blenheim-Gilboa (1973). Figure 2-4 illustrates the increase in capacity due to these plants which cumulatively added almost 4,000 MW of reversible power to the national total. The reasons for development of this capacity during this period are several fold including the optimistic outlook for nuclear power with its relatively inexpensive off-peak pumping power; the need for back-up and replacement of older oil-fired generating units, particularly in the Northeast; the need for regional emergency reserve; and the need to streamline operations of larger nuclear and coal-fired units.

The above projects also highlight major innovations in plant design. Northfield Mountain (see Section 2.3.2 for a more complete discussion) was the first plant to employ a completely underground, unlined powerhouse excavated over a half-mile within the mountain and reached by a 26-foot diameter access tunnel. The Ludington Project (see Section 2.3.3) is currently the largest pumped storage project in the United States and utilizes Lake Michigan for its lower reservoir, eliminating problems with reservoir drawdown and water supply.

Secondly, during the early 1970's the environmental movement gained momentum, and supported by the Federal Water Pollution Control Act Amendments of 1972 (Clean Water Act), exerted increasing pressure on pumped storage developers. The effects of environmental opposition are possibly best illustrated by the sequence of pumped storage projects proposed by the Power Authority of the State of New York. In June of 1968 the Authority filed for an FPC license to build and operate the Blenheim-Gilboa project (see Section 2.3.5) on Schoharie Creek, 40 miles southwest of Albany, New York. Ten months later the license was

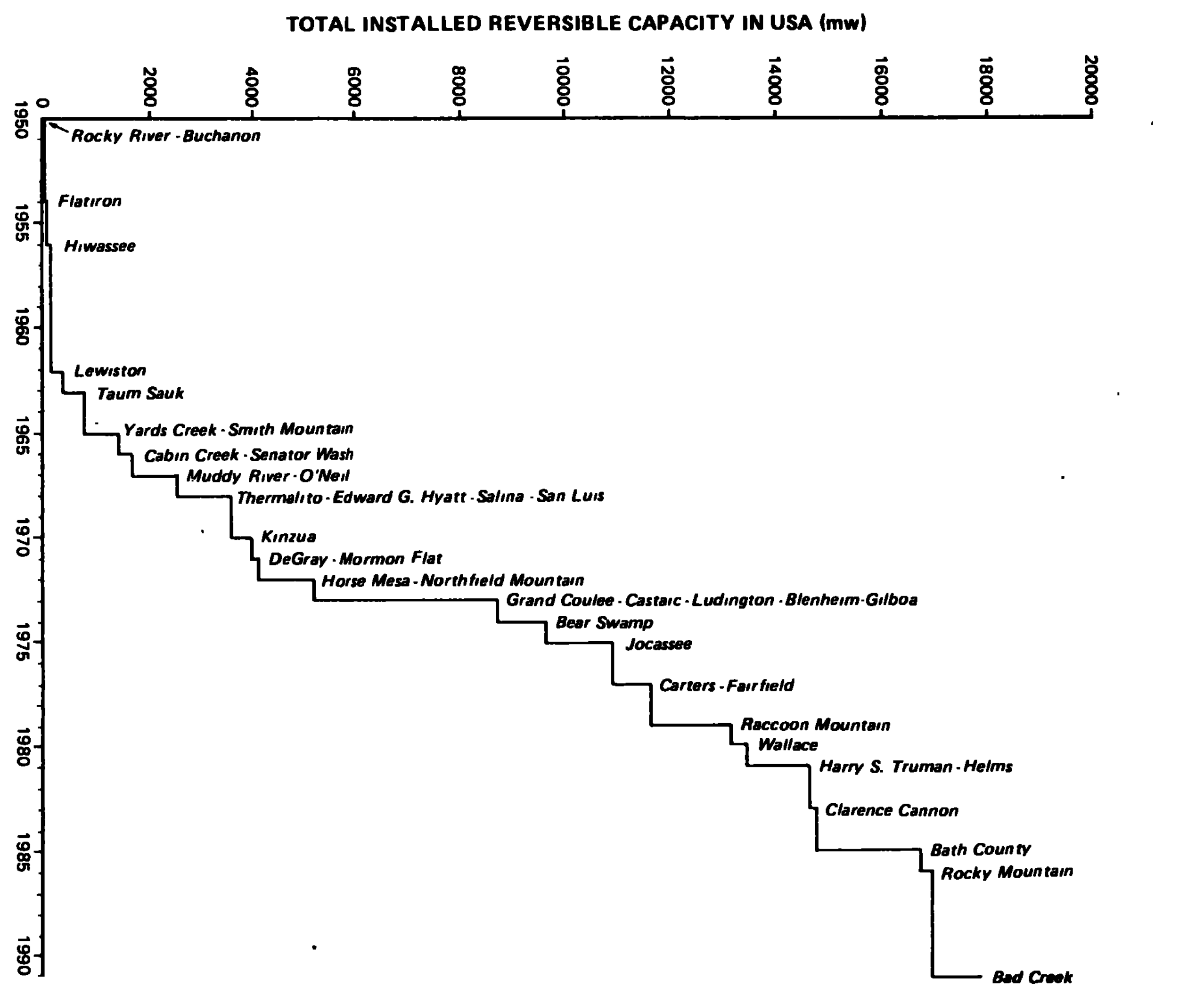


FIGURE 2-4
TOTAL INSTALLED REVERSIBLE CAPACITY IN USA
HYDROELECTRIC PUMPED STORAGE FACILITIES

granted and Blenheim-Gilboa was built without unexpected delays. Approximately 5 years later, in March 1973, the Authority applied for a license to construct a similar facility, the Breakabeen project (see Section 2.3.6) just downstream from Blenheim-Gilboa. Even before completion of the Draft Environmental Impact Statement required by the National Environmental Protection Act (NEPA), it was evident that opposition from environmental groups and local property owners would not allow development of the project on a reasonable schedule. As a result, approximately 4 years after initial application, the Authority formally requested that the alternative Prattsville site located just upstream from Blenheim-Gilboa, be licensed in place of Breakabeen. Although using an existing reservoir and planning the powerhouse, penstocks, and tailrace underground, the opposition to the project was just as severe as with Breakabeen. At present, 3½ years after recommendation of Prattsville and 7½ years after the original license application, no compromise has been reached and the project is in hearings with its future uncertain.

Similarly, the proposed Cornwall Project has had a long and rocky history. On March 9, 1965, the Federal Power Commission issued a 50-year license to the Consolidated Edison Company of New York, Inc., for the construction, operation, and maintenance of the project, to be located on the Hudson River about 40 miles north of New York City. The Commission's license order was contested and, in December 1965, the Second Court of Appeals remanded the proceeding to the commission for further consideration. Following a hearing examiner's decision in August 1968, recommending that the project be licensed, the commission in November 1968, reopened the hearing to determine whether construction of the project would constitute a hazard to the aqueduct supplying a part of New York City's water system, and whether the project powerhouse should be relocated. Following those hearings, the commission, on August 19, 1970, issued a new license for the project. That license order was also contested, but it was upheld by the Second Circuit Court of Appeals, Scenic Hudson Preservation Conference vs. Federal Power Commission, CA 2, No. 35678 (October 22, 1971), and affirmed by the Supreme Court of the United States on June 19, 1972. Construction was further delayed, however, by litigation pending in New York State courts. By March 1973, all appeals in both Federal and State courts had been concluded and the licensee proceeded to initiate construction of the project. Before any significant construction had been completed, however, intervenors were successful in having the court stay construction, contending that there was new evidence showing that the effects of the project on the Hudson River fishery had not been adequately considered. The Commission then set that issue for hearing, but the hearing has been repeatedly delayed. Consequently, a project that was estimated to cost $130 million, exclusive of transmission facilities, would now cost at least ten times that amount. Consolidated Edison Company has recently applied to FERC to surrender its license for the Cornwall project.

The above related cases illustrate one of the major issues affecting the development of pumped storage through the 1980's and 1990's. Not only are delays important for project cost reasons, but they have a considerable impact on utility system planning, an effect that will be discussed further in Section 2.4.3.

During the last three decades of progress in pumped storage utilization in the United States, the Federal Government has played an important role in project development:

- The DeGray Plant was the first pumped storage project put in operation by the U.S. Army Corps of Engineers in 1971; it is on the Caddo River near Arkadelphia, Arkansas, and includes a 40-MW conventional unit and a 28-MW reversible unit
- Thirteen years after the Flatiron Project went on-line, the eight-unit 424-MW San Luis project was constructed by the U.S. Bureau of Reclamation (now the Water and Power Resources Service) as a part of the Bureau's Central Valley Project; it is operated by the California Department of Water Resources
- The Water and Power Resources Service's Colorado River Front Work and Levee System includes a pumping-generating plant at the Senator Wash Dam offstream of the Colorado River in California, near Yuma, Arizona
- In 1975 the Corps of Engineers completed the multipurpose Carters Project on the Coosawattee River, near Carters in Murray County, Georgia.

Historically, however, the development of pumped storage capacity as part of Federal projects has been secondary to primary objectives such as irrigation storage and flood control.

Table 2-1 is a summary of the pumped storage projects currently in operation. Figure 2-5 shows the location of these projects nationally, and in addition, 12 other plants under construction or with Federal authorization to proceed with construction. Construction of two plants, Davis and Cornwall, is currently stayed by court proceedings.

In some instances the addition of pumped storage capacity has been the determining factor in the development of a generation site. One example is the Corps of Engineers' Harry S. Truman Dam and Reservoir, a key flood control unit in the Osage-Marais des Cyques river basin. The feasibility of a pumped storage project at the same site was studied several years earlier by Union Electric Company, which operates the Taum Sauk Plant. The project proved not to be economically feasible when considering only hydroelectric generation potential and was dropped. The Corps of Engineers, however, was able to show justification for the pumped storage component in a multi-objective setting, and Congress directed the Corps to proceed with the project.

In recent years, however, the need for further peak-load generating capacity has diminished, and this drop has occasionally jeopardized the completion of a project. The Bath County Project, about 25 miles northeast of Covington, Virginia is one example. The project was initially scheduled to go on line in 1982, but in January 1980 the project's owner, the Virginia Electric and Power Company (VEPCO), announced that completion would be delayed to 1984, and in May 1980 they announced a further delay to 1985. These delays were a result of the sharp drop in peak-load growth. However, to render the project feasible once again, in October 1980 VEPCO entered into an agreement to sell from 40 to 50 percent of the project power to the Allegheny Power System, making the project justifiable on the basis of its contribution to both utilities' systems.

In the licensing proceedings involving the Bath County Project, a significant issue raised was the socioeconomic impact on neighboring Highland County. Most of the construction workers were expected to reside there while the tax benefits of the project would go to Bath County where all project works will be located. Because Highland County could not absorb the added governmental costs that would result from the influx of construction workers, the license requires that the project owner must compensate Highland County for additional expenses for education, law enforcement, waste disposal, government costs, and welfare and

TABLE 2-1

Pumped Storage Projects in the United States in Operation as of November 1, 1980

Project or Plant name	State	Owner or developer	Year of initial operation	Gross Static Head (ft)	Installed Capacity in megawatts		
					Revers-ible	Conven-tional	Total
Rocky River (1)**	Connecticut	Connecticut Light and Power Co.	1929	230-200	7*	24	31
Buchanan (2)	Texas	Lower Colo. River Authority	1950	Unavailable (UA)	11*	23	34
Flatiron (3)	Colorado	Water and Power Resource Service	1954	290-140	9	63	72
Hiwassee (4)	North Carolina	Tennessee Valley Authority	1956	243-134	60	57	117
Lewiston (5)	New York	Power Authority of the State of New York	1961	100-65	240		240
Taum Sauk (6)	Missouri	Union Electric Co.	1963	863-755	408		408
Yards Creek (7)	New Jersey	Jersey Cntl. P. & L. Co., Public Service E. & G. Co.	1965	760-688	387		387
Smith Mountain (8)	Virginia	Appalachian Power Co.	1965	195-174	236	300	536
Cabin Creek (9)	Colorado	Public Service Co. of Colorado	1966	1,226-1,170	300		300
Senator Wash (10)	California	Water and Power Resources Service	1966	74	7		7
Muddy Run (11)	Pennsylvania	Philadelphia Electric Co.	1967	411-361	800		800
O'Neill (12)	California	Water and Power Resources Service	1967	56-44	25		25
Thermalito (13)	California	California Department of Water Resources	1968	102-86	82	33	115
Edward G. Hyatt (14)	California	California Department of Water Resources	1968	670-508	293	351	644
Salina (15)	Oklahoma	Grand River Dam Authority	1968	246-228	260		260
San Luis (16)	California	Water and Power Resources Service	1968	327-101	424		424
Kinzua (17)	Pennsylvania	Cleveland Elec. Illum. Co. & Pennsylvania Electric Co.	1970	813-668	396	26	422
DeGray (18)	Arkansas	Corps of Engineers	1971	188-144	28	40	68
Mormon Flat (19)	Arizona	Salt River Project Power District	1971	132	49	9	58
Horse Mesa (20)	Arizona	Salt River Project Power District	1972	295-151	100	30	130

*Turbines are not reversible; separate pumps are used.
**Project Number--see Figure 2-5 for location.

TABLE 2-1 (cont'd)

Pumped Storage Projects in the United States in Operation as of November 1, 1980

Project or Plant name	State	Owner or developer	Year of initial operation	Gross Static Head (ft)	Installed Capacity in megawatts		
					Reversible	Conventional	Total
Northfield Mtn. (21)	Massachusetts	Connecticut Light and Power Co.	1972	825-720	1,000		1,000
Ludington (22)	Michigan	Consumers Power Company & Detroit Edison Co.	1973	362.5-295.5	1,978		1,978
Blenheim-Gilboa (23)	New York	Power Authority of the State of New York	1973	1,143-1,055	1,000		1,000
Castaic (24)	California	Los Angeles City & State of California	1973	1,088-1,022	1,275	56	1,331
Grand Coulee (25)	Washington	Water and Power Resources Service	1973	362-266	314		314
Jocassee (26)	South Carolina	Duke Power Company	1974	335-280	610		610
Bear Swamp (27)	Massachusetts	New England Power Co.	1974	770-680	600		600
Carters (28)	Georgia	Corps of Engineers	1975	392-352	250	250	500
Raccoon Mtn. (29)	Tennessee	Tennessee Valley Authority	1979	1,040-890	1,530		1,530
Fairfield (30)	South Carolina	South Carolina Elec. & Gas Co.	1979	169-155	511		511
Wallace (31)	Georgia	Georgia Power Company	1980	97-94	216	108	324
			Total		13,406	1,370	14,756

FIGURE 2-5
LOCATION OF HYDROELECTRIC PUMPED STORAGE PLANTS

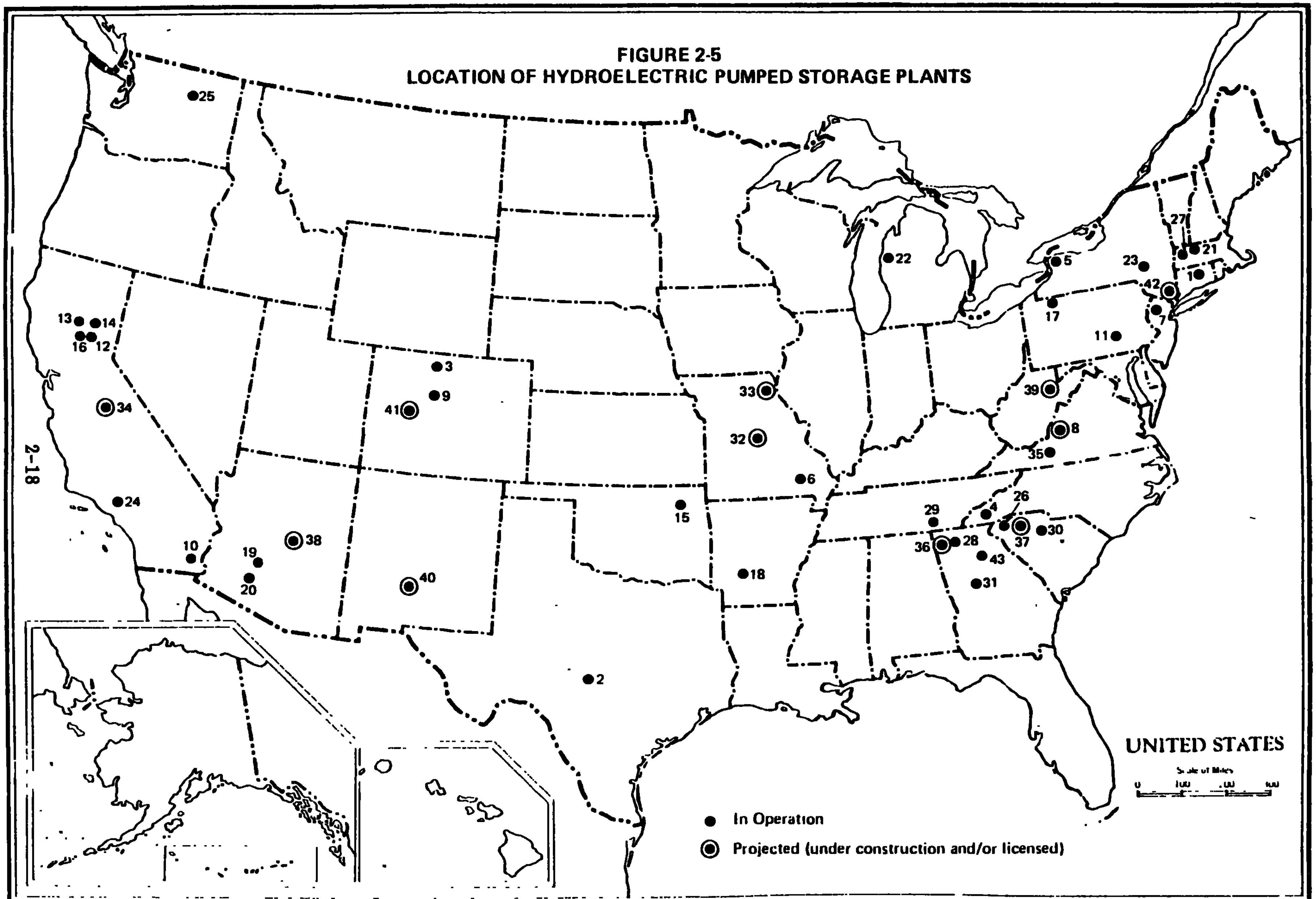


FIGURE 2-5 (cont'd)

Legend

Project Number	Project Name	State
1	Rocky River	Connecticut
2	Buchanan	Texas
3	Flatiron	Colorado
4	Hiwassee	N. Carolina
5	Lewiston	New York
6	Taum Sauk	Missouri
7	Yards Creek	New Jersey
8	Smith Mountain	Virginia
9	Cabin Creek	Colorado
10	Senator Wash	California
11	Muddy Run	Pennsylvania
12	O'Neill	California
13	Thermalito	California
14	Edward G. Hyatt	California
15	Salina	Oklahoma
16	San Luis	California
17	Kinzua	Pennsylvania
18	DeGray	Arkansas
19	Mormon Flat	Arizona
20	Horse Mesa	Arizona
21	Northfield Mountain	Massachusetts
22	Ludington	Michigan
23	Blenheim-Gilboa	New York
24	Castaic	California
25	Grand Coulee	Washington
26	Jocassee	S. Carolina
27	Bear Swamp	Massachusetts
28	Carters	Georgia
29	Raccoon Mountain	Tennessee
30	Fairfield	S. Carolina
31	Wallace	Georgia
32	Harry S. Truman	Missouri
33	Clarence Cannon	Missouri
34	Helms	California
35	Bath County	Virginia
36	Rocky Mountain	Georgia
37	Bad Creek	S. Carolina
38	Montezuma	Arizona
39	Davis	W. Virginia
40	Seboyeta	New Mexico
41	Mt. Elbert	Colorado
42	Cornwall	New York
43	Richard B. Russell	Georgia

social services attributable to the influx of temporary project workers, to the extent those expenses exceed taxes and fees attributable to those workers.

The development of a number of other projects in recent years has also been slowed by unexpected events or intervention. The Arizona Power Authority, in June 1968, received a license authorizing construction of the four-unit 505.4-MW Montezuma pumped storage project to be located on lands of the Gila River Indian Reservation about 20 miles southwest of Phoenix. The high evaporation rate in Arizona (about 7 feet of water per year in some areas) will require additional pumping per unit of power generated, but the overall reduction in efficiency would be negligible. The fate of this project is uncertain, however, because the licensee has not found a firm market for the power that would be developed. To date, only minor construction has taken place.

In another case, on April 21, 1977, the Federal Power Commission issued a license to three subsidiaries of the Allegheny Power System, namely, the Monongahela Power Company, Potomac Edison Company, and West Penn Power Company, authorizing construction of the 1,025-MW Davis pumped storage project on the Blackwater River and Reed Creek in Tucker County, West Virginia. The Commission adopted the proposal of the companies which included a 7,000-acre lower reservoir in Canaan Valley, thus rejecting an alternative site known as Glade Run that would have the same upper reservoir as Davis but a lower reservoir having a surface area of only 785 acres. The latter had been recommended by an Administrative Law Judge in an initial decision issued on June 10, 1976. The Sierra Club and the Department of the Interior have contested the license issued by the Commission, and the Corps of Engineers has denied the licensees a dredge-and-fill permit needed for construction. These two issues are now awaiting decisions in separate court proceedings. As a result, the Commission has stayed the terms of the license pending the court appeals.

Table 2-2 lists the pumped storage projects now under construction and/or licensed by FERC. The total capacity to be added to the nation's generating capability when (and if) these projects are complete is 9,346 MW. It is pertinent to note that the average capacity of these 11 plants (to be completed after 1980) is 850 MW. In comparison, the average size of plants in operation before 1980 as listed in Table 2-1 is 432 MW. This illustrates the distinct trend to larger plants made possible by the turbine/pump advances previously discussed.

TABLE 2-2

Pumped Storage Projects in the United States
Licensed and/or Under Construction, November 1, 1980

Project or Plant Name	State	Owner or developer	Gross Static Head (ft)	Capacity in Megawatts		
				Reversible	Conventional	Total
Harry S. Truman (32)*	Missouri	Corps of Engineers	Unavailable (UA)	160		160
Clarence Cannon (33)	Missouri	Corps of Engineers	107-59	31	27	58
Helms (34)	California	Pacific Gas and Electric Co.	1,560	1,050		1,050
Bath County (35)	Virginia	Virginia Electric and Power Co	1,050	2,100		2,100
Rocky Mtn. (36)	Georgia	Georgia Power Co.	652	675		675
Bad Creek (37)	South Carolina	Duke Power Co.	UA	1,000		1,000
Montezuma (38)	Arizona	Arizona Power Authority	1,690-1,620	505		505
Davis (39)	West Virginia	Allegheny Power System	864-803	1,025		1,025
Seboyeta (40)	New Mexico	Public Service Co. of New Mexico	UA	600		600
Mt. Elbert (41)	Colorado	Water and Power Resoures Service	485-430	200		200
Cornwall (42)	New York	Consolidated Edison Co. of N.Y.	1,160-1,000	2,000		2,000
Richard B. Russell (43)	Georgia	Southeastern Power Administration	UA	300	300	600
		Total		9,646	327	9,973

*Project number--see Figure 2-5 for location.

Each year the American Society of Civil Engineers selects the outstanding civil engineering achievement of the year. It is noteworthy that on four occasions pumped storage developments have been involved in those awards. In 1969, Oroville Dam and the underground Edward G. Hyatt powerplant that contains reversible generating units received the award. In 1972, it was the California Water Project, which carries surplus water from northern California to water-short central and southern California and extends some 700 miles. Included in that project are four pumped storage plants: Edward G. Hyatt, Thermalito, San Luis, and Castaic. The 1973 outstanding achievement award went to the Ludington pumped storage project, and the 1975 award went to Duke Power Company's Keowee-Toxaway power system, which includes the Jocassee pumped storage project as well as nuclear and conventional hydroelectric plants. These awards are given for the engineering project that "demonstrates the greatest engineering skills and represents the greatest contribution to engineering progress and mankind."

In summary, the history of pumped storage development is one of progressive growth since the first serious consideration of the technology in the United States led to the small combined plants of the 1950's. This growth was accelerated during the 1960's and again in the 1970's until recent circumstances began stimulating a reevaluation of generation system demands for the 1980's.*

The following section focuses on six projects that illustrate a variety of technical, environmental, and economic characteristics of pumped storage plants, the decisions that resulted in their construction, and the results of their operational histories.

---

*All pumped storage projects referred to in this report are included in the inventory presented as Appendix A.

2.3 Case Studies and Project Briefs

In this section, the following case studies are presented:

Taum Sauk Pumped Storage Project

Northfield Mountain Pumped Storage Project

Ludington Pumped Storage Project

Helms Pumped Storage Project

Blenheim-Gilboa Pumped Storage Project

Breakabeen/Prattsville Pumped Storage Project.

2.3.1 Case Study--Taum Sauk Pumped Storage Plant

2.3.1.1 General

The Taum Sauk Pumped Storage Plant was completed in June 1963, by the Union Electric Company. The plant is located on the East Fork of the Black River about 80 miles southwest of St. Louis, Missouri. Figure 2-6 diagrams the physical layout of the facility. The 408-MW plant was constructed at a cost of $45,854,000 (1963 dollars) including the switchyard and transmission facilities. This is equivalent to $112 per kilowatt of capacity. At the time of completion the two 204-MW pump/turbines were the largest hydroelectric units in the United States, reversible or conventional. The decision to use units that were significantly larger than any previously employed in the United States* was heavily influenced by European success with such units under similar high head conditions. The Providenza Project in Italy, completed in 1962, had attained heads of 860 feet with units designed by Allis Chalmers who also manufactured the Taum Sauk turbine/pumps. Using these units Taum Sauk was able to operate under 764 feet of gross head. Previously the 290-foot head at the then Bureau of Reclamation's Flatiron Project was the highest in the United States.** Furthermore, the advances made in development of the reversible Francis turbine/pump allowed the use of one

*The 20-MW units at the Lewiston Plant in New York were the largest units installed in the United States prior to Taum Sauk.

**Since power output is directly proportional to operating head, such a major increase greatly affected the economics of hydroelectric projects, particularly pumped storage facilities.

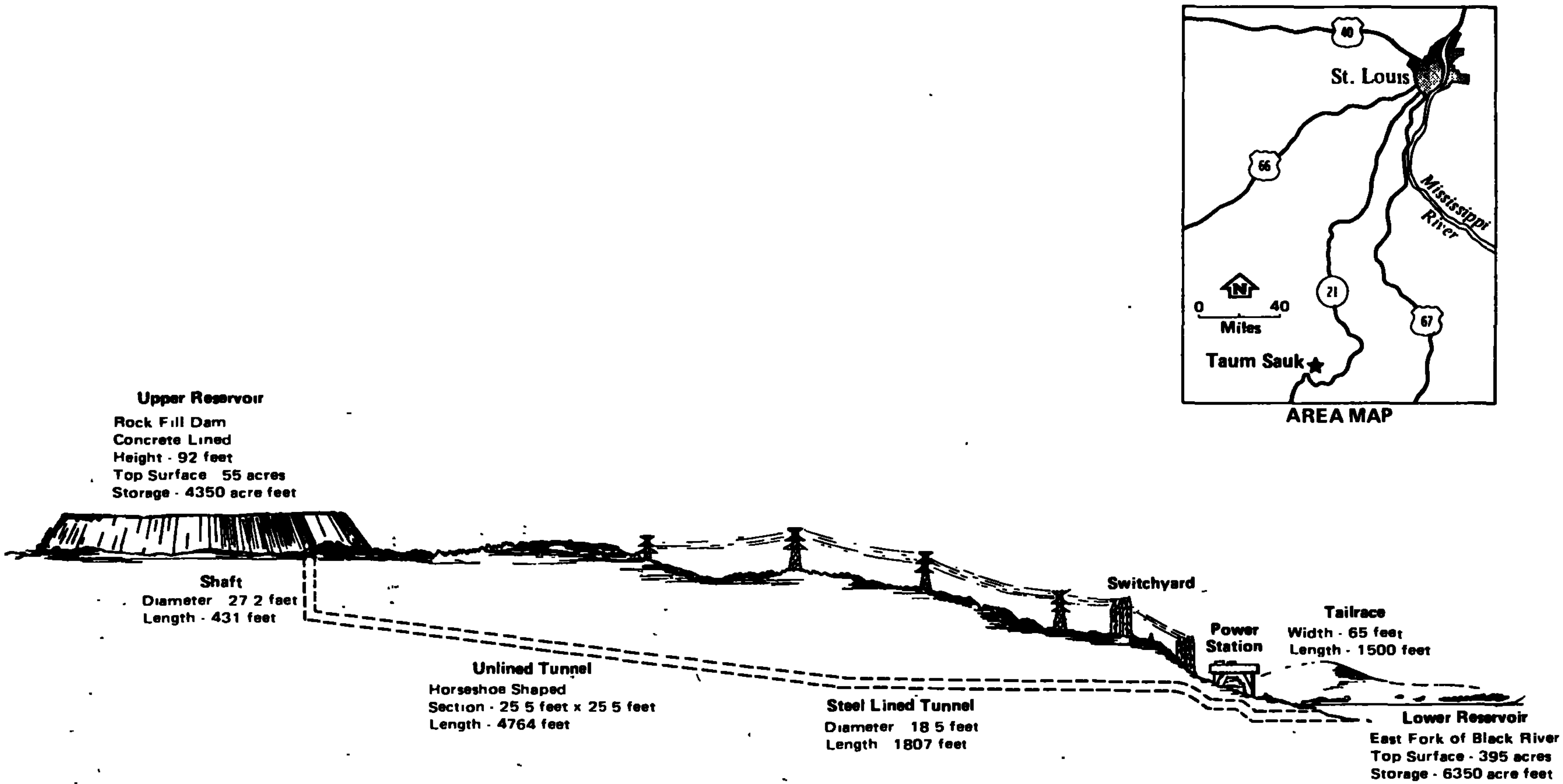


FIGURE 2-6
PHYSICAL LAYOUT
TAUM SAUK PUMPED STORAGE PROJECT

unit for both pumping and generating which resulted in a large cost savings when compared to using separate machines for each purpose.

The upper reservoir for the plant was built on Taum Sauk Mountain about 1,500 ft. above sea level and consisted of a 32-acre pool with a 10-foot parapet wall constructed on the crest of the embankment to gain additional storage capacity. The lower reservoir is formed by a 60-foot high dam. The upper reservoir has a usable storage capacity of 4,350 acre-feet of water, which is equivalent to 2,700 MWH of electric generation or 7.7 hours of operation at full load. The plant can actually provide 445,000 KW of power for a short period of time with a full reservoir.

The licensing of the Taum Sauk Plant deserves attention because of the precedent setting decision made by the Supreme Court regarding the jurisdiction of the Federal Power Commission. Section 23(b)* of the Federal Power Act requires any person desiring to construct a dam or other project on a nonnavigable stream, but one over which Congress has jurisdiction under its authority to regulate commerce, to file a declaration of intent with the Federal Power Commission. If the FPC finds that "the interests of interstate or foreign commerce would be affected by such proposed construction", a license must be issued by the FPC before construction may begin. A declaration of intent was filed by Union Electric Company for Taum Sauk in 1960. Since the project was located on a "non-navigable" stream totally within the borders of the State of Missouri, Union Electric Company maintained that the FPC did not have jurisdiction and commenced construction in 1960 without an FPC license. In 1962 the FPC determined that it did have jurisdiction and ordered a license application to be submitted by Union Electric. This ruling was negated by the Eighth Circuit Court of Appeals which decided in favor of Union Electric Company. On May 3, 1965, this ruling was reversed by the U.S. Supreme Court which affirmed the Commission's licensing authority over Taum Sauk. In writing the opinion, Justice White concluded that:

- The interstate transmission of electricity is fully subject to the commerce powers of Congress.

---

*The Federal Power Act was originally enacted in 1920 as the Federal Water Power Act, 41 Stat. 1063. The original Act was amended by Title II of the Public Utility Act of 1935, 49 Stat. 838 and made Part I of the Federal Power Act.

- Projects such as Taum Sauk which generate electricity for transmission affect commerce among the states and are therefore under the Congress' commerce power whether or not the Congress controlled nonnavigable tributary streams.

- It was the intent of Congress to require a license for water power projects utilizing the headwaters of a navigable river to generate energy for interstate power systems.

As a result Union Electric Company applied for and received a license to construct and operate Taum Sauk on August 26, 1965, two years after construction was completed. While it is difficult to determine the impact of this decision on the development of pumped storage in the United States, an opposite determination by the Supreme Court may have had a tremendous influence on siting of pumped storage plants. With the connection of virtually every active pumped storage plant to interstate transmission systems all plants except Seboyeta have required a Federal license. It has not been determined at this time whether the Federal Power Act will require licenses for underground pumped storage plants which use closed systems located off navigable waters and their tributaries.

2.3.1.2 Rationale for Development

An analysis of projected load growth and generation demands by Union Electric Company in the mid-1950's showed that the need of the system was primarily for peaking power since coal-fired steam units in operation were adequate for baseload power. There were no oil or nuclear plants in the system at the time. Since all economically feasible conventional hydroelectric sites had been developed and gas combustion turbines were in the development stage (those in production were too small for Union's requirements) pumped storage proved to be the most economical alternative. As alternatives, oil fired cycling boilers were also considered but did not meet the specifications required by the generation mix of the system. Interestingly, hydroelectric plants including Taum Sauk accounted for about one third of Union Electric's total generating capacity in 1966.

Other potential sites for the project were considered including some along the shores of the Mississippi River and the site at the Lake of the Ozarks which was later developed by the Corps of Engineers as the Harry S. Truman Pumped Storage Project. The potential sites along the Mississippi River, which were to use the river as the lower reservoir, were dropped when geologic studies identified the existence of limestone caverns which would have raised construction costs considerably.

2.3.1.3 Operational History

The Taum Sauk Plant is remotely operated from the Osage Plant at the Lake of the Ozarks and the master console at the Union Electric Dispatcher's Office in St. Louis. The maintenance staff at the plant consists of 10 persons. The annual operations and maintenance expenditures for 1979 totaled $972,000, but included a significant percentage for major scheduled replacements and repairs of machinery. As a result, the actual efficiency of the plant has recently been returned to predicted values of about 55 percent after several years of operating at efficiencies of about 45 percent. Normal weekday operations include generation for about four hours with one of the two units. Maximum drawdowns are 17 and 80 feet in the lower and upper reservoirs respectively. The utilization factor for the plant ranges from five to eight percent. This is relatively low when compared to the 20 percent utilization factors of other plants such as Blenheim-Gilboa and is due to the different operating philosophies and generation mix of various utilities. While some plants log many hours of generating time due to the outage or higher maintenance requirements of older fossil-fueled or nuclear plants in the system, the Taum Sauk Plant responds primarily to small loads at the top of the demand curve and has had only minor use as an intermediate load replacement facility. The high percentage of conventional hydro capacity in the Union system, particularly during the 1960's and early 1970's, also has contributed to the lower utilization factor of the Taum Sauk Plant, since conventional hydro is well suited to peak and intermediate load generation (see Section 2.1.2).

Power from Taum Sauk is used primarily by Union Electric although both daily and longer-term contract power, including spinning reserve, is sold to the Tennessee Valley Authority and Southwestern Power Administration. The plant was originally designed to allow operation in the condensing mode but due to economics the equipment was disconnected in 1966.

Upon licensing in 1965 a recreation plan was developed for the facility and included building of a museum and construction of boating and fishing facilities on the lower reservoir. As has occurred in other pumped storage projects, Union Electric was concerned about the liability of operating recreational facilities on the lower reservoir due to the fluctuating water level. As a result, the Missouri Conservation Commission operates the recreational facilities at the site.

2.3.1.4 Summary

The Taum Sauk Plant was a major step in the development of pumped storage due to the capacity and operating head of its turbine/pumps and the total capacity of the plant. The Supreme Court's decision that the project was under the jurisdiction of the FPC has been an important factor in the licensing of later facilities. Although it fills a critical role in the Union Electric system, the low utilization of the plant stands in contrast to more recent projects with different system demands.

2.3.2 Case Study--Northfield Mountain Pumped Storage Project

2.3.2.1 General

The Northfield Mountain Pumped Storage Plant is a multipurpose hydroelectric project developed and operated by Northeast Utilities. The 1,000-MW capacity project was constructed on the Connecticut River near the border of New Hampshire and Massachusetts in the towns of Northfield and Erving, Massachusetts. Figure 2-7 indicates the physical layout and general location of the project. The underground powerhouse at Northfield Mountain, the first underground powerhouse of its type, houses four, 250-MW reversible pump/turbine generators which, at the time of construction, were capable of meeting almost 45 percent of the peak demand experienced by Northeast Utilities' members.*

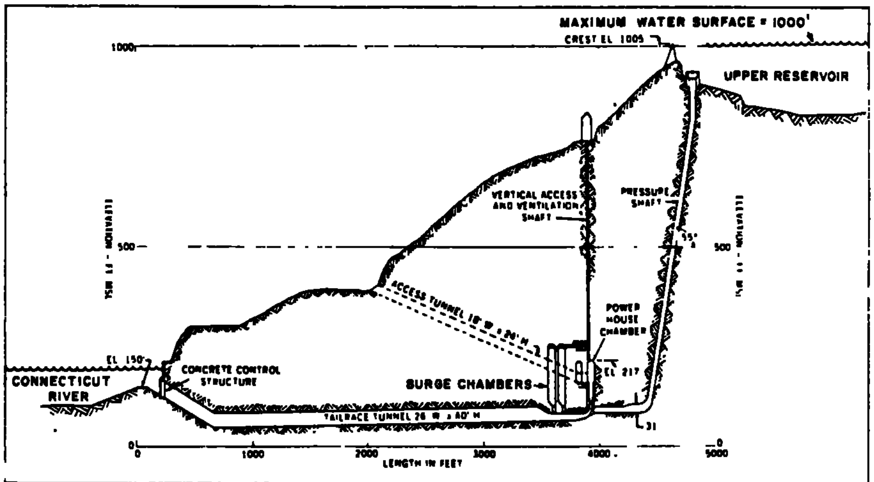
The project includes, in addition to hydroelectric generating capacity, a water supply objective that allows transfer of up to 50 million cubic feet daily to the Massachusetts Metropolitan District Commission's Quabbin Reservoir for use in the Boston area water supply system. To accomplish this, spring flows in excess of 15,000 cfs in the Connecticut River downstream of Turner's Falls Dam will be pumped to the upper reservoir of the Northfield Mountain Project. Historical flows indicate that average flows in the river will be in excess of 15,000 cfs on about 70 days. For such an average year, up to 26 billion gallons of water could be diverted to Quabbin Reservoir. This quantity, however, is less than 1 percent of the annual flow of the Connecticut River, although it would increase the flow to Boston from Quabbin Reservoir by about 25 percent.

To allow for the additional storage capacity in the upper reservoir, the dam and dikes of the upper reservoir were constructed 4 feet higher. In addition, a separate water supply intake in the upper reservoir allows connection of the planned 10-foot diameter gravity tunnel to convey water to Quabbin Reservoir, which is 500 feet in elevation below Northfield Mountain's upper reservoir.

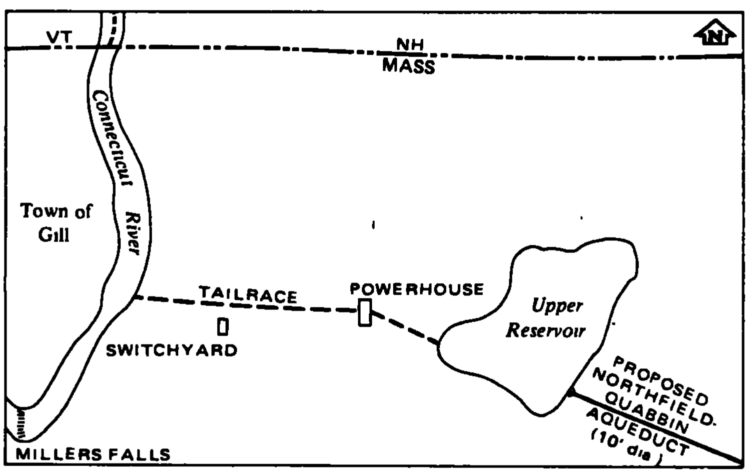
Presently no contract or agreement has been signed between the Metropolitan District Commission (MDC) and Northeast Utilities for construction of the line. The MDC has been ordered by the state legislature to perform an

---

*Northeast Utilities includes Connecticut Light and Power Co., Holyoke Water Power Co., Western Massachusetts Electric Co., Northeast Utilities Service Co., New England Nuclear Energy Co., and Hartford Electric Light Co.



PROJECT PROFILE



AREA MAP
(not to scale)

FIGURE 2-7
PHYSICAL LAYOUT
NORTHFIELD MOUNTAIN PUMPED STORAGE PROJECT

environmental assessment of the proposed transfer project. The study is not complete as of this date, and it appears that a decision to construct the tunnel will not be made in the near future.

Hydroelectric generation facilities at the project include an upper reservoir with a live storage capacity of 12,750 acre-feet and an estimated power potential of 8,500 MWH, a 34-foot diameter penstock, a 300-foot long by 70-foot wide by 120-foot high unlined powerhouse chamber excavated in bedrock, a 31-foot diameter tailrace tunnel and the existing Turner's Falls Reservoir which serves as a lower reservoir. Turner's Falls Dam was originally constructed by Western Massachusetts Electric Co. to provide conventional hydroelectric generation capability. The underground powerhouse served as a milestone in pumped storage development in the United States made possible by advances over the previous decade in blasting techniques, methods of handling and transporting rock, and more efficient techniques in anchoring and rock bolting.

In addition, an extensive plan was implemented for development of recreational facilities in conjunction with the lower reservoir created by the existing Turner's Falls Dam. Facilities for camping, boating, winter sports, fishing, horseback riding, and hiking have been constructed as part of the project. The operating companies of Northeast Utilities have also conducted a program to restore shad and other fish species to the river by providing fish passage and protection devices at the Turner's Falls dam.

In all, construction costs for the project totaled $140 million in 1973 or about $140 per kilowatt of capacity.

2.3.2.2 Rationale for Development

Planning studies performed in 1964 by the member companies of the Connecticut Valley Electric Exchange (CONVEX) and the Electric Coordinating Council of New England indicated that the service area needed additional generating capacity and that peaking power requirements were of paramount importance. The combination of high transportation costs for coal and dependency on oil for energy in New England worked to make the area attractive for development of nuclear power during the 1960's. As a result low cost, off-peak generation capacity available from planned nuclear plants made pumped storage especially attractive as a peaking source. (See discussion in Section 2.4.2.)

Site and economic studies performed by CONVEX indicated that the Northfield Mountain Project would best meet the need for short hour generation, fluctuating peak loads, and emergency reserve power (emphasized by the 1965 blackout in the area). The application for a Federal Power Commission license was submitted on January 14, 1966, by the three members of Northeast Utilities at that time. Previously a preliminary permit for feasibility studies had been granted to Massachusetts Electric Company, one of Northeast Utilities' member companies. The license was approved in mid-1967 and construction started in September of that year. Construction was delayed approximately six months due to accidental flooding of the powerhouse cavity. Unfortunately, generators and other equipment were inundated during the flood, adding significantly to the final cost of the plant.

Original cost estimates made during feasibility studies indicated a construction cost of approximately $75 million. By the date construction commenced the estimate was about $110 million. As previously stated, final construction cost was approximately $140 million. The operating schedule of the plant is based on a modified weekly cycle with most of the pumping occurring on weekends. Additional pumping occurs during early morning hours on weekdays but not enough to replace the water used for generation that day. As a result a gradual drawdown of the upper reservoir storage occurs over the week, with complete replenishment occurring on Saturday and Sunday. The plant was intended to operate in harmony with the existing fossil-fueled and nuclear base load plants and conventional hydro plants. Original planning proposed that actual hour-by-hour peak demand fluctuations be met by a combination of pumped storage and conventional hydro, with conventional hydro actually meeting peak demands on weekdays. Although planned to function as part of the CONVEX system, by the time it was placed on-line Northfield Mountain was dispatched against the entire New England load.

2.3.2.3 Operational History

The Northfield Mountain Plant, can best be described as a reliable, powerful operating tool for the CONVEX dispatcher. Although the ratio of pumping energy to generating energy has been rising slowly since 1973 (1.34 in 1973 to 1.37 in 1980), the plant maintains a 25 percent utilization factor* and is used constantly during peak load periods to meet a wide variety of demands on the system. For

*Based on a maximum daily generation potential of 2,500 MWH/day.

example, when the Connecticut Yankee nuclear plant was unexpectedly lost to the system recently, the Northfield Mountain Plant was called on (via automatic controls at the dispatchers office) to increase its output from 150 MW to 750 MW in less than two minutes. Later the same day the New England Power Exchange's (NEPEX) computers malfunctioned and nuclear units could not respond to demand changes. The Northfield Mountain Plant was automatically loaded to its full 1,000 MW capacity again within two minutes. With the total electric generating capacity of all Northeast Utilities Plants being 6,000 MW, the 1,000 MW of Northfield Mountain is a major component of the system. In addition, the plant is being called upon to operate more often in the synchronous condensing mode thus providing voltage regulation to the system when required, especially during periods of low demand.

The Northfield Plant requires a total staff of 35 persons for operation and maintenance of the 1,000 MW facility. In comparison, the Mt. Tom oil fired plant in Holyoke, Massachusetts, has an operating staff of 20 with a capacity of 150 MW. As a result of this and other factors (such as the cost of fuel, environmental equipment, maintenance downtime, etc.), the operation and maintenance costs for Northfield Mountain average about $1.90 per kilowatt year while operating costs at Mt. Tom are approximately $12 per kilowatt year in 1979 dollars. The Northfield Mountain operation costs would be significantly lower but for the need for cavitation repair work, unit balancing, and dewatering of the upper reservoir for the plant's five year inspection. While most of this maintenance has been accomplished during the offpeak seasons, operating costs have been well above average for the last two years.

Environmentally, to the knowledge of Northeast Utilities, the Northfield Plant has had no serious impacts and local acceptance of the project has been good. On-going studies of fishing potential indicate that the tailrace area may need to be protected from fish access. Methods of providing access for anadromous fish such as shad are being considered presently. Having been planned and licensed without the necessity of an Environmental Impact Statement, the effects on local flora and fauna would be difficult to determine at this time due to the lack of environmental baseline information.

2.3.2.4 Summary

The Northfield Mountain Plant fills a critical role in the Northeast Utilities electric supply system. While the ratio of pumping energy to generating energy could be lowered through modifying schedules, the operating philosophy over the years has shown a trend toward using Northfield Mountain at a less than optimal mode to maximize efficiency at larger, less flexible fossil-fueled and nuclear plants. Northfield Mountain has the advantages of most pumped storage plants including "black start" capability, spinning reserve capability, low operating costs, low maintenance costs relative to alternative peaking options, and ability to provide synchronous condensing. Other key aspects of the plant include:

- The underground powerhouse, penstocks, and tailrace reduce environmental impacts when compared to above-ground facilities. This is an important factor which may be a key to successful licensing and development of pumped storage plants in the future, since most such facilities by nature are located in relatively undeveloped or rural settings to facilitate reservoir construction and where water is relatively "free" and available. As a result, the areas most suitable for pumped storage development tend to be most sensitive to damage to the natural environment due to construction and operation. The solution may be underground facilities, including underground reservoirs. This will be discussed further in Section 2.4.1.

- The construction cost of $140 per kilowatt of generating capacity when combined with reliability and low operation costs made a very attractive investment at the time of development. Obviously, construction and operating costs are significantly higher today, but relative to other alternatives, pumped storage may still be very competitive.

In recent years the decline of peak load growth and the postponing of construction of nuclear plants (which provide the cheapest source of off-peak pumping energy in New England) have combined to put the planning of pumped storage projects on hold. Northeast Utilities' current 20-year plan does not call for development of any additional pumped storage capacity. While peak load demand has leveled, the off-peak (base) load is still rising. This allows existing nuclear and fossil-fueled plants to supply a higher percentage of the total demand thus reducing somewhat the need for additional pumped storage capacity. This trend is off-set, however, by the need in New England to replace old, oil-fired plants which currently provide a high percentage of the total capacity of the area. As such plants are retired, nuclear facilities will pick up the load, thus moving down on the demand curve and requiring pumped storage and/or conventional hydro to meet peak demand again.

2.3.3 Case Study--Ludington Pumped Storage Project

2.3.3.1 General

The Ludington Pumped Storage Project, jointly owned by Consumers Power Company (51 percent) and Detroit Edison Company (49 percent), is located on the eastern shore of Lake Michigan, about four miles south of Ludington, Michigan. Figure 2-8 is a general physical layout of the plant with a location map. The plant is the largest pumped storage facility currently in operation, with a rated capacity of 1,978-MW that is capable of producing 2,076 MW of peaking power. It was designed and constructed at a cost of $322 million, including transmission lines and transfer stations. The plant provides about 15 percent of the combined system-wide electric generating capacity of both owners.

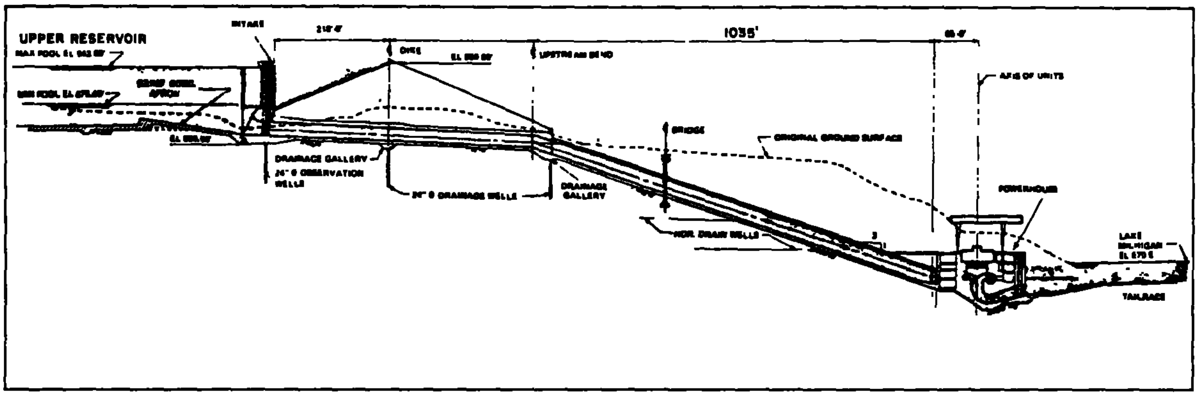
The Ludington Plant is unique in that it uses Lake Michigan as its lower reservoir in combination with a manmade upper reservoir, which has a live storage capacity of 54,000 acre-feet. Using Lake Michigan not only reduced construction costs but eliminates the need to draw down a lower reservoir during the pumping cycle. The upper reservoir at Ludington was constructed on a plateau and is enclosed by a six mile long, 103-foot high dike, which creates a 1.75 square mile reservoir with a storage capacity of 15 million KWH when full.

In addition to meeting the systems' needs for peaking power, at various times the plant:

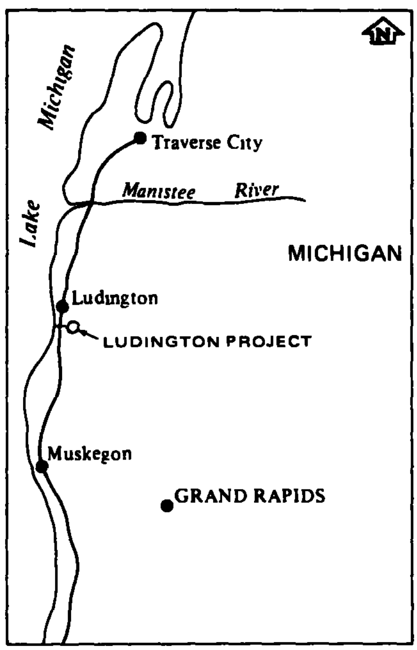
- Satisfies the owners' requirements for spinning reserve.
- Provides emergency power for both the owners and Commonwealth Edison Company, which supplies electricity to the City of Chicago.
- Can be used in the condensing cycle to control system voltage during low load periods.*
- Is used to meet constantly fluctuating demands during generation that allows baseload fossil fuel and nuclear plants to operate at a constant level.

---

*During synchronous condensing the turbine-pump/generators are neither generating nor pumping, but are spinning and allow "absorption" of system voltage.



PROJECT PROFILE



AREA MAP

FIGURE 2-8
PHYSICAL LAYOUT
LUDINGTON PUMPED STORAGE PROJECT

Construction of the plant was begun in 1969 and took four years, with initial start-up of two turbines in March of 1973. Initial feasibility studies, including site selection, were begun in 1959.

2.3.3.2 Rationale for Development

In 1959, Consumers Power Company conducted a site selection study for Michigan's Lower Peninsula, addressing the load growth expected to occur during the 1960's. The study included investigations of more than sixty potential sites, but the proximity of the Ludington site to demand centers, in addition to other factors, made it the most attractive. Other advantages included its location on Lake Michigan, proximity to the port facilities at Ludington, and availability of native soils suitable for dike construction.

Initial feasibility studies in 1959 indicated that the plant should consist of five 100-MW units, to be used entirely by Consumers Power Company. Due to the mild recession of 1958-61 and the associated decline in load growth, along with the economic attractiveness of fossil fuel plants during that general period, the project was postponed for about five years. During this time, Consumers Power Company and the Detroit Edison Company reached an agreement to coordinate their transmission and generating systems, including the Ludington Plant when it was developed. Also during this period, load growth increased rapidly; plans for an extra-high voltage transmission network were formed, including interconnection with utilities in Ohio, Indiana, and Canada. (The existence of 138-KV transmission lines, particularly in the vicinity of Ludington, was an additional factor initially precluding development of the pumped storage plant. Such lines do not have the capacity to transmit power from a plant as large as Ludington.) Another factor influencing the development of the Ludington project was the planned installation of additional fossil fuel and nuclear baseload plants in the system (Forgey, 1974).

A re-evaluation of the plant's feasibility was performed in 1967, showing that the optimum initial storage capacity was 15 million KWH. (This proved to be the ultimate design capacity of the facility.) However, it was also concluded that this capacity was too large for integration into the Michigan Electric Coordinated Systems Network until 1983. As a result, the owners reached an agreement with Commonwealth Edison Company of Chicago for purchase of one-third of the power from 1973 until 1983 and one-sixth of the capability between 1983 and 1988.

Commonwealth Edison agreed to provide proportional amounts of pumping power and to pay for transmission line losses during this period.

Table 2-3 is a chronology of the planning and development of the Ludington Pumped Storage Project.

TABLE 2-3

Chronology of the Ludington Pumped Storage Project

Preliminary Investigation Started	January 1959
Received FPC License	July 1969
Start of Construction	July 1969
Testing of First Generation Unit	October 1972
Commercial Operation of First Unit	January 1973
Commercial Operation of Last Unit	October 1973
Completion of Recreation Facilities	May 1974

The construction of the powerhouse, penstocks, reservoir, and other facilities, extending over almost four years, was completed within 20 days of the schedule established in 1966, three years before construction began. This is a considerable accomplishment considering both the immensity of the construction effort and the innovative systems which had to be built to meet unique requirements.

A key accomplishment of the Ludington Project was the research and development of a special asphalt mix for lining the dikes of the upper reservoir. The mix had to be impervious to water, deformable, resistant to ice erosion and free from cracking and fissuring from age or heat exposure. The resulting hydraulic asphalt concrete was a major step forward in reservoir lining technology.

During the height of the construction effort, over 2,800 workers were on the job. More than 50 million cubic yards of earth had to be moved during the winter and summer seasons. Approximately 300,000 cubic yards of concrete were poured in winter as well as summer. Although it was greater than the $110 per kilowatt cost estimated during the planning period in 1967, the final construction cost of $175 per kilowatt was lower than the engineer's 1970 estimate. This includes transmission lines, the switchyard, and substation. Part of this savings was the result of value engineering performed on the reinforced concrete design for the plant.

2.3.3.3 Operational History

The Ludington Plant was initially justified based on a projected daily generating schedule of from four to six hours during peak demand periods. Over seven years of operation, use of the plant has increased steadily to the extent that it now generates ten or more hours per day. The Ludington units are significantly more reliable than steam units, with annual maintenance costs less than half that of fossil fuel plant costs. The pumped storage plant requires a crew of 33 men, less than one-fifth the size of a crew for a steam plant of equal size.

Unexpected outage of units at Ludington has been virtually nonexistent. Normal maintenance on the equipment is performed during the low peak demand seasons of spring and fall.

Normal annual operation and maintenance costs for the plant are estimated at about $1 million. This figure was exceeded in 1979, due to the need to investigate and correct leakage from the upper reservoir. The leakage was thought to be occurring through the bottom of the clay lined reservoir. To prevent a rise in the local groundwater table because of reservoir leakage, a series of 40 wells were constructed at the periphery of the reservoir to maintain groundwater levels at historic levels. It appears that the leakage has been controlled with present pumpage from the wells stabilizing at 7 cubic feet per second, about half that originally experienced and within predicted bounds.

Environmentally, the project has resulted in predicted effects. Although the project was developed before requirements of the National Environmental Policy Act were in effect, environmental planning was performed as an integral part of the project. Recreational facilities, including a campground and scenic overlook developed as part of the project, have been well used by the local community and tourists. Studies by Michigan State University on the effects of the project on local fisheries indicate that the upper reservoir now contains all of the fish species found in Lake Michigan. Loss of fish passing through the pump/turbines is as predicted but has not significantly changed the species or number of fish in Lake Michigan in the vicinity of the intake/outlet (Brazo, 1979).

Another environmental concern expressed during project planning, and continuing during operations, was the problem of bank erosion along much of the eastern shore of Lake Michigan and the potential of the Ludington Project exacerbating the problem. This was investigated by Consumers Power Company during feasibility studies and again after start-up. The conclusion reached by these studies is that the problem will neither be mitigated nor worsened by the jetties and intake/outlet works of the project. The Corps of Engineers plans to continue investigation of the problem.

2.3.3.4 Summary

The Ludington Pumped Storage Project fills a key role in the electric supply network of Consumers Power Company and the Detroit Edison Company. This is confirmed by the increased usage of the plant over the years of its operation. Highlights of the Ludington Plant's development include:

- The final construction cost in 1974 for the plant, substation, and transmission lines was $175 per kilowatt.
- The plant has the capability of providing approximately 300 MW in less than 10 minutes and can reach full output of 1978-MW from standstill in 30 minutes.
- The plant provides the utility with the ability to adjust generation output on a minute-by-minute basis to meet constantly fluctuating system demands. This allows base load plants to operate at a steady rate, significantly increasing their efficiency.
- A major reason for increased utilization of the pumped storage plant is its reliability. The plant is called upon frequently to pick up loads due to outage of less dependable fossil fuel power facilities.
- All of Ludington's units are capable of starting and being brought to full generation under "black start" conditions.
- Operating costs are significantly less than those of other plants in the system.
- Consumers Power Company was able to delay the construction of large and more expensive steam plants.

As a result of the success and demand for the Ludington Plant, Consumers Power Company is investigating additional pumped storage capacity along Lake Michigan.

2.3.4 Case Study--Helms Pumped Storage Project

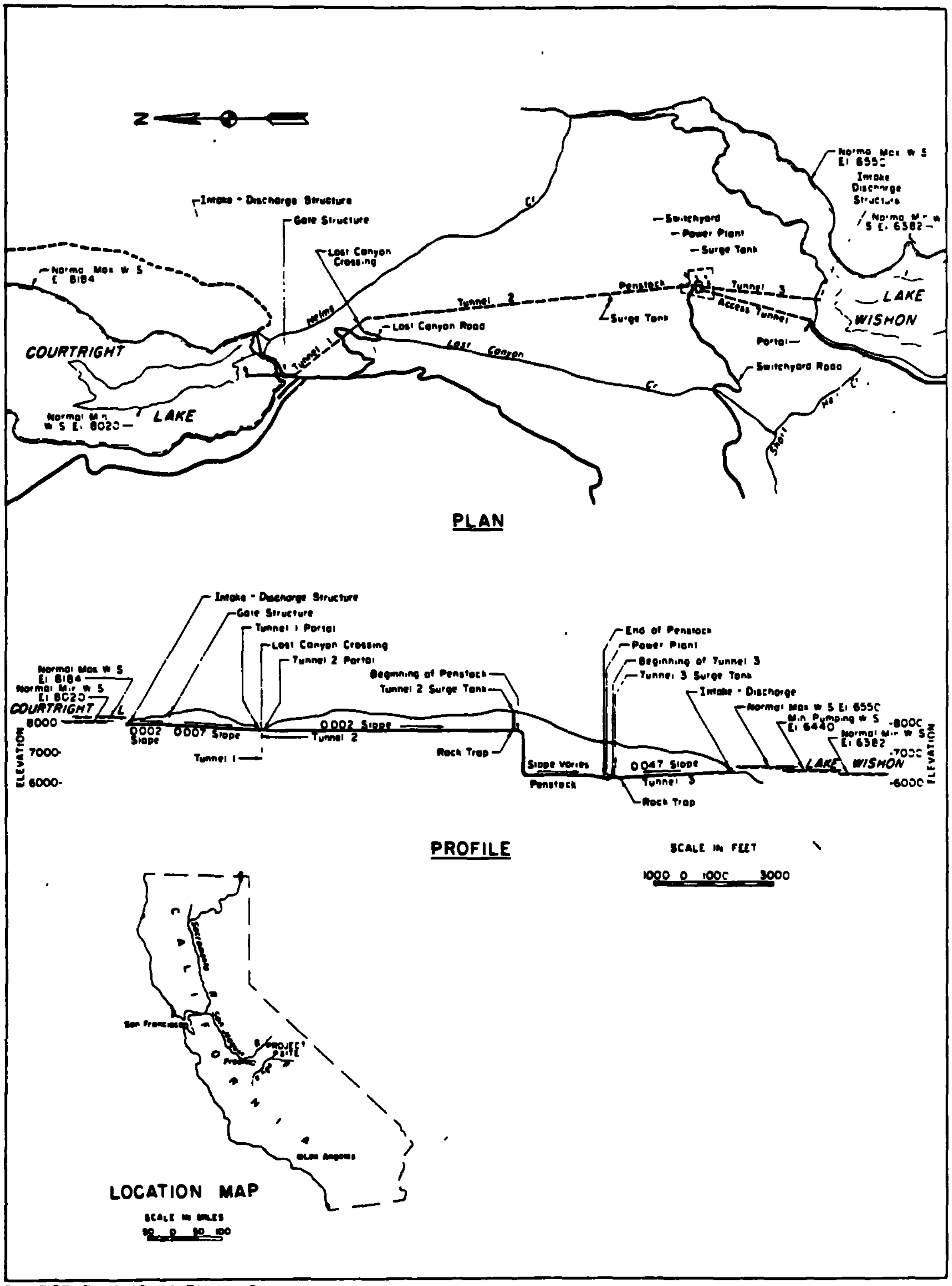
2.3.4.1 General

The Helms Pumped Storage Project, scheduled to be in operation in June 1983, is being developed by Pacific Gas and Electric Company (PG&E). The project is located about 70 miles northeast of Fresno, California. Figure 2-9 shows the physical layout and general location of the plant. The original estimated construction cost for the plant was $186,500,000 in 1973 dollars or about $178 per kilowatt of installed capacity.

The pumping and generating facilities will be constructed underground, linking the existing Courtright Reservoir on Helms Creek with the Wishon Reservoir on the North Fork Kings River. Both reservoirs are located on the western slope of the Sierra Nevada Mountains, about 70 miles east of Fresno, California. Wishon and Courtright Reservoirs are also part of PG&E's North Fork Kings River Hydroelectric Project. The Helms' Project's 60-mile 230-kV transmission line will connect the power generating facilities to a proposed substation to be located 12 miles northwest of Fresno. Most project facilities will be located within the Sierra National Forest, although portions of the transmission line would traverse other public and private lands. All project facilities would be located within Fresno and Madera Counties. About 5000 acres of land are required by the project, most of which are part of the Sierra National Forest. Approximately 1,400 acres of this land are for transmission lines.

The powerhouse, including both pumping and generating facilities, will be constructed about 1000 feet underground between the two existing reservoirs. The unlined powerhouse chamber will be 320 feet long, 75 feet wide and 65 feet high. The plant will utilize three 480,000 hp vertical Francis turbines capable of generating 350 MW each. The total operating capacities of the plant are as follows:

Operating Mode	Net Head (ft)	Electrical Capacity (MW)	Turbine Capacity (hp)	Water Flow (cfs)
Generating	1,560	1,050	1,440,000	9,000
Pumping	1,500	1,035	1,365,000	7,200



SOURCE. Pacific Gas & Electric Company

FIGURE 2-9
PHYSICAL LAYOUT
HELMS PROJECT

A single 38.5 foot diameter penstock, handling both pumping and generating flows, will branch into three 90 inch diameter steel pipes. Only 150 feet of the four mile penstock will be exposed above ground. Other facilities being constructed are typical of a pumped hydro project and include surge chambers, access roads, intake/outlet structures, trash racks, slide gates, compressed air equipment switchyards, transformer units and exciter switchgear. A horizontal access shaft and a vertical elevator shaft are also under construction.

Plans for operation of the facility include a microwave communication system from the Fresno dispatcher's office to the project area via a passive reflector mounted on top of Hall Mountain about four miles from the project. This will allow almost instantaneous response of the generating capability to either emergency or normal peak demands.

The existing Courtright Dam is a concrete faced, rockfill embankment about 315 feet high with a crest length of 862 feet. The Wishon Dam is a rockfill embankment measuring 260 feet high and 3,330 feet long with a concrete upstream face. Water surface elevations above sea level and capacities for the two reservoirs are:

	Maximum W.S. Elevation	Minimum W.S. Elevation	Gross Capacity
Courtright Lake	8,184 ft. msl	8,020 ft. msl	123,300 AF
Wishon Lake	6,550 ft. msl	6,382 ft. msl	128,600 AF

Recreation plans for the project include rehabilitating three existing campgrounds, construction of a new 30-unit campground, parking areas and access roads to the reservoirs for fishing, development of picnic areas, boat launching facilities, and a scenic overlook.

Construction of the project was commenced in 1976 and plans currently call for a seven and one-half year construction schedule. Creation of a "small town," housing over 200 single workers and 350 families, will be required during the peak of the effort. Construction is scheduled for completion in late 1983.

2.3.4.2 Rationale for Development

In addition to the 1,050 MW capacity of the Helms Project, PG&E had at the time of the feasibility study 21 other electric generation projects planned for operation by 1981. If all 21 projects followed the original licensing and construction schedule, the generating capacity available to the PG&E system during the summer of 1982 would be 15,216 MW. Contribution of other utilities to the system by 1982 was estimated at 4,926 MW of generating capacity. When including the 892 MW of transfers from other systems and a planned maintenance schedule which would make 300 MW unavailable, the net projected generating capacity of the system for the summer of 1982 was 20,734 MW.

Estimates of the California Public Utilities Commission projected a peak demand for the summer of 1982 as 19,000 MW. In review of the project the Federal Power Commission reduced this forecast by 430 MW due to existing diversity of loads in the system and by another 140 MW for interruptible load (demand which by contract may be interrupted during peak loads, as necessary). As a result the forecasted demand was 18,430 MW resulting in a reserve of 2,304 MW or a reserve margin of 12.5 percent. (Reserve margin is the difference between the net generating capacity and net load responsibility, expressed as a percentage of load responsibility). Without the Helms Project the reserve margin would be 7.3 percent. Pacific Gas & Electric requires a 12 percent reserve margin. As a result, the Helms Project was considered to be justified by need, especially in light of the fact that delay or deferral of any of the other 21 projects would further increase that need.

Alternatives to Helms which were considered during project review included:

- Nuclear steam
- Fossil steam
- Geothermal steam
- Simple and combined cycle combustion turbines
- Coal-fired steam peaking
- Conventional hydroelectric
- Other pumped storage projects
- Purchase of power
- Conservation

- Rate structuring
- No action

At the time of the FPC review (1975) more "exotic" alternatives including solar power, wind power, storage batteries, fly wheel storage systems and magneto hydrodynamic power were not considered as reasonable alternatives. The addition of nuclear or fossil-fueled steam plants as alternatives to Helms was discounted early since such plants would tend to function more as base load facilities pushing older plants up into the intermediate cycling category making the system less efficient. The rationale for this conclusion was that during low demand months, when the system load would not be high enough to require full output of the 1,050-MW Helms Plant and other available hydro capacity, it would be necessary to operate base load facilities at low plant factors or to allow spillage over dams of inexpensive hydro energy. The operation of expensive, base load plants at low plant factors was not considered an economically viable alternative.

In consideration of other pumped storage plants as alternatives to Helms, it was evident that it would be at least three additional years (1984) before another plant could be put on-line if Helms were not built. Four other sites for equal sized projects were studied and discounted for environmental, economic, and other reasons.

The FPC also studied the potential for purchase of power from neighboring sources, including the Pacific Northwest. The study concluded that although off-peak transmission capability existed, other systems could not supply the needed peak capacity in 1981 due to their own direct commitments and even if they were available, on-peak transmission capability was not available.

It was concluded regarding the potential effects of conservation and rate revision that:

> "While improved conservation measures such as redesign of rates should be pursued vigorously, the uncertainties of the effects of specific rate redesigns and other conservation measures on the load characteristics of an electric system, the time lag associated with consumer responses, and the long times required for constructing new capacity, severely reduce the practical potential of rate revision and conservation as alternatives, at this time, to the scheduling of projected needed additional generating capacity. Accordingly, these measures cannot be considered as reasonable alternatives to the proposed Helms Project." (FPC, 1975)

Since PG&E had plans to develop 732 MW of geothermal, base-load generating capacity by 1980 (which was considered in reviewing need for the project), it was concluded that further geothermal capacity would not replace the peaking capability of Helms but would rather act as additional base-load capacity.

For the above reasons, final alternatives to Helms consisted of simple-cycle combustion turbines, combined cycle combustion turbines, and coal-fired steam peaking systems. Cumulative present worth total annual system costs for the study period of 1981-2000 were:

Alternative	PW Cost ($ million)
Helms Project	8,449
Simple Cycle Turbines	8,717
Combined Cycle Turbines	8,760
Steam Peaking Plant	8,989

Note that these present worth costs for the 20-year period are in millions of dollars and that, although the percent difference between the Helms project (lowest) and steam peaking plant (highest) is only six percent, it amounts to $540 million.

It is significant that the latest (1980) estimate of total construction cost for the project is approximately $600 million or 3.2 times the estimate at the time of FPC review of the project in 1975. Although this is a considerable increase, it is equivalent to about $571/KW which is low relative to estimated 1980 costs for other projects in the planning stage.

2.3.4.3 Environmental Considerations

Although the Helms project would utilize two existing reservoirs and include an underground penstock, powerhouse, and tailrace, it was not without significant environmental concerns. Construction of the intake/outlet structures required drainage to low levels of the two lakes necessitating capture and removal of fish in the reservoirs. Visual impacts due to cutting of the access road to the powerhouse and construction of the switchyard, transmission lines, and microwave towers will be significant.

Probably the most significant environmental issue was the method of disposal of over 700,000 cubic yards of rock excavated during construction of underground facilities. It was proposed that this material be placed in the bottom of Lost Canyon covering an area 1,325 feet long and 110 feet wide. This is being accomplished without major environmental opposition, probably resulting from the remoteness of the canyon and lack of significant negative environmental impacts.

The Helms project stands out among those which either began construction or applied for licenses during the late 1970's. While many projects experienced severe opposition from local and national environmental groups often causing lengthy delays in schedules (see the Breakabeen/Prattsville case study), the Helms project proceeded relatively smoothly into construction. This is notable since the project is located in an environmentally sensitive area--within the Sierra National Forest and about one-mile from the Jon Muir Wilderness Area.

Much of the reason for this success lies with the approach Pacific Gas & Electric Company (PG&E) took regarding public involvement during project planning. Well publicized, yet informal, public meetings were held with local citizens, environmental groups, and state agencies both before and after application for license was submitted. Feedback, including suggestions on project design, was gathered and incorporated into project plans. Site visits were made with interested groups to provide clearer understanding of the project's impacts. As a result of these meetings PG&E was able to determine local community priorities, compensate for them in project design and avoid expensive delays later due to unexpected opposition.

2.3.4.4 Proposed Operation of Helms Plant

The planned operating schedule for the project includes about 6 hours of daily generation with variations from four to twelve hours as system demands require. Pumping would occur at night and on weekends. In addition to daily drawdowns of the upper reservoir, weekly drawdowns would occur with levels in Courtright Lake reaching a maximum early Monday morning (8,184 ft.) and a minimum Friday evening (8,176 ft.). Annual drawdowns of the storage capacity in both reservoirs would occur during late summer and fall. This will be offset by storing more water in the upper reservoir during spring runoff to replace the larger withdrawals from Lake Wishon (lower reservoir) during dry seasons.

Objectives of the project include, in addition to peaking power, supply of spinning reserve, emergency reserve, and voltage regulation. The emergency response capability of Helms will be particularly significant since its 1,050 MW of capacity will be linked not only to PG&E's system but also to the Bonneville Power Administration's 500 KV network. Helms will thus be capable of meeting emergency needs anywhere in an interconnected system which extends from Portland, Oregon, to San Diego, California.

2.3.4.5 Summary

On completion, the Helms Project will be a major component of the PG&E generating system supplying peaking capacity of 1050 MW. Estimated construction costs for the project have risen from $186,500,000 in 1973 to $600,000,000 recently, reflecting a 12 percent annual cost escalation which is typical when compared over this period to similar projects of this size. The more lengthy construction schedule which will result in project start-up about two years later than originally planned, is part of the reason for increased project costs.

The ability to plan, license and begin construction of the Helms project with a minimum of local and environmental resistance is a major accomplishment. The maintenance of a reasonable budget and schedule is to a great extent the result of two factors:

- Site selection and design of the project which allows use of two existing reservoirs and underground placement of almost the entire physical system except the switchyard and transmission lines.
- The considerable effort made by PG&E to incorporate local and environmental priorities and concerns into project planning early in the development process.

Objectives and justification of the project were typical to that of most pure pumped storage projects, with the exception that the Helms capacity will be available to respond to needs of a very large geographic area due to the interconnection of the PG&E system with that of the Bonneville Power Administration.

TABLE 2-4

Chronology of the Helms Project

1969	Feasibility studies begun
October, 1973	License application filed
November, 1975	Final EIS sent to CEQ
May, 1976	License granted by FPC
October, 1976	Construction begun
December 1983	Projected start-up

2.3.5 Case Study—Blenheim-Gilboa Pumped Storage Project

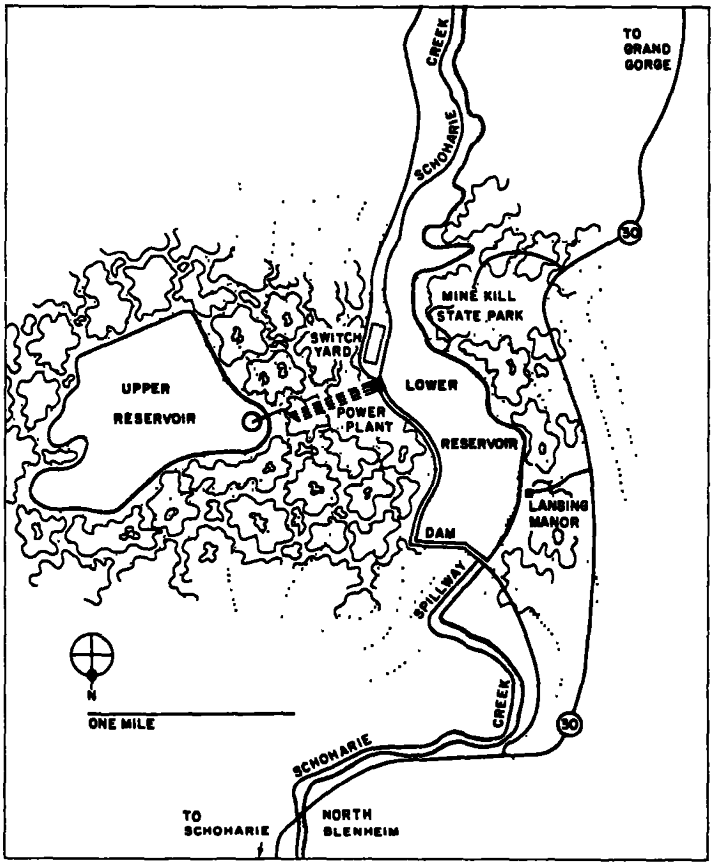
2.3.5.1 General

The Blenheim-Gilboa Pumped Storage Project was built by the Power Authority of the State of New York between 1969 and 1973, the same time that Consumers Power was constructing the Ludington Project in Michigan. Figure 2-10 illustrates the physical layout and location of the facility. The Blenheim-Gilboa facility, about 40 miles southwest of Albany, was part of the 1970 Project of the Authority which also included the James A. Fitzpatrick Nuclear Power Plant east of Oswego, New York on Lake Ontario and transmission lines for each project. Total estimated construction cost in 1974 for the 1970 project was $544 million, including $200,000,000 for the Blenheim-Gilboa Plant. The plant has a total generating capacity of 1,000 MW from four 250-MW turbine pumps located in a powerhouse which has three stories above ground and nine floors of equipment below ground.

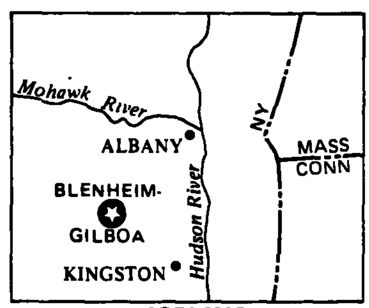
The Blenheim-Gilboa Plant utilizes a manmade impoundment on Schoharie Creek for a lower reservoir. A 100-foot high rockfill dam about one mile downstream of the powerhouse was built to create a 430-acre lake with a capacity of 15,500 acre-feet. The upper reservoir was located on top of Brown Mountain and has a live capacity of 15,000 acre-feet or 12 million kilowatt hours of generation. The gross head between the two reservoirs is about 1,100 feet with both having a maximum operational drawdown of about 40 feet.

The Power Authority of the State of New York is a public benefit corporation directed by five trustees appointed by the Governor. The Authority is a wholesale power supplier and sells its power to municipally- and cooperatively-owned electric systems in Vermont, New Jersey, Pennsylvania, and New York, to investor-owned utilities and to private industry. Before being assigned the responsibility for developing the Blenheim-Gilboa Project, the Authority has financed, built, and operated the 800-MW St. Lawrence Power Project on the St. Lawrence River and the 2,400-MW Niagara Power Project at Niagara Falls. These projects represented an investment of over $1.1 billion by the Authority.

Table 2-5 is a chronology of the development of the Blenheim-Gilboa project. Note that the date of acceptance of the Federal Power Commission License, June 16, 1969, was only 10 months after the date of application to the FPC, August 15, 1968. Although an environmental assessment under NEPA was not required,



SOURCE Power Authority of the State of New York



AREA MAP

FIGURE 2-10
PHYSICAL LAYOUT
BLENHEIM - GILBOA PUMPED STORAGE PROJECT

TABLE 2-5

Chronology of the Blenheim-Gilboa Pumped Storage Project

Governor Nelson A. Rockefeller signs bill authorizing Power Authority of the State of New York to develop nuclear and pumped storage facilities	May 21, 1968
Power Authority applies for Federal Power Commission license to construct project	August 15, 1968
Power Authority formally accepts Federal Power Commission License	June 16, 1969
Groundbreaking	July 12, 1969
Transmission line plans submitted to Federal Power Commission	November 24, 1969
Federal Power Commission approves routing of two transmission lines	April 10, 1970
First concrete placed	May 20, 1970
Temporary Visitors' Center opened	July 13, 1970
First turbine runner and shaft installed	January 18, 1972
Two transmission lines placed in service	July 27, 1972
First power	July 5, 1973
Project dedication	July 31, 1973
Full power	December, 17, 1973
Dedication of Lansing Manor Visitors' Center	July 30, 1974

considerable study and planning were directed at environmental factors. Plans were incorporated into the project for establishing fish populations in the reservoirs, providing deer migration routes, and protection of white cedar trees. The recreation plan implemented along with the hydroelectric plant development included a visitors center, development of Mine Kill State Park with associated swimming pools, bathhouses, boat launching ramps and picnic areas, and preservation/restoration of the historic Lansing Manor complex as a major information, education, and scientific center. This old farm, built in the early 1800's overlooking Schoharie Creek, is listed in the National Register of Historic Places. It is interesting to note that from 1718 until 1916 water in the Schoharie Creek was harnessed for power to run grain mills, lumber mills, and manufacturing plants. As many as 70 hydropower facilities were located on the river at one time before 1916 when Empire State Power Company retired the last plant which had a 1,500 kilowatt capacity.

2.3.5.2 Rationale for Development

The objectives of the Blenheim-Gilboa Plant were essentially the same as those for the Ludington Project and most pure pumped storage systems: to provide reliable, quick-response peaking capacity and to allow base load plants to operate at relatively constant generation levels. The Blenheim-Gilboa Plant has two 400-kilowatt diesel starter motors allowing the plant to come on-line with full capability within 45 minutes under "black-start" conditions (complete black out with no power from other plants in the system).

In the pumping cycle the plant uses inexpensive power from the Niagara Hydro Project on weekends and the Fitzpatrick Nuclear Plant on weekday nights. An additional advantage of the Blenheim-Gilboa Plant which was considered during planning was the facility's potential for allowing "fuel selection" or storage of energy from more readily available fuels to use during periods of peak demand. In other words, a pumped storage plant permits pumping energy to be supplied by units where the most available (or inexpensive) fuels are located and generating with this stored energy during peak demand, allowing units burning fuels in short supply to be used less or shut down. In more complex electric supply systems, such as that in New York, this capability may be of considerable importance.

The plant is also used for voltage regulation, emergency back-up power, and to satisfy spinning reserve requirements of the New York Power Pool.

Initially the plant was planned for operation only on weekdays for a limited generation period. The utilization factor of the plant for economic justification had to be 2.1 percent. The facility is actually operating at a significantly higher factor as will be discussed in Section 2.6.3.

2.3.5.3 Operational History

The Blenheim-Gilboa Pumped Storage Plant has more than met the expectations of the Authority during its seven years of operation. Currently, the plant provides almost 15 percent of the 6,888-MW peak generating capacity of the Authority. Originally justified by a utilization factor of 2.1 percent, the plant has operated at above 20 percent regularly. On start-up in 1973, the plant was used to generate only one or two hours on Saturday. Today it generates with 2 to 3 units for several hours on Saturday and Sunday.

Annual generation, which remained relatively constant at about 1,220,000 MWH for the first several years of operation, has increased significantly over the last year to over 1,720,000 MWH.* This increase has been caused by the outage and retiring of fossil-fueled plants such as the Indian #1 Plant near New York City. The additional maintenance requirements at both fossil and nuclear powered plants have also contributed to the increased usage of the Blenheim-Gilboa Plant. Table 2-6 indicates the total annual generation, pumping, and system support usage of the plant. System support includes such operations as condensing for voltage regulation.

2.3.5.4 Summary

Feasibility studies performed in 1967 indicated that the New York Power Pool not only had need for additional peaking capacity but also that old fossil-fueled power plants had to be retired in favor of more reliable, efficient units. When it went on-line in 1973, the Blenheim-Gilboa Pumped Storage Plant provided 1,000 MW of the Authority's total generating capacity of 4,200 MW. The storage capability of Blenheim-Gilboa allows the Authority to off-load less efficient thermal units with higher heat rates during periods of peak loading. In addition, as with most pumped storage projects it provides spinning reserve capacity for emergency response and can be operated in the condensing mode for voltage

*Based on January through September generation data proportionately increased through the end of 1980.

TABLE 2-6

Blenheim-Gilboa Plant Usage
(MWH)

Calendar Year	Total Pumping	Total Generating	System Support
1973	672,089[a]	453,045[a]	7,516.5[a]
1974	1,174,861	1,226,957	11,442.7
1975	1,758,586	1,226,602	10,861.8
1976	1,916,470	1,316,763	13,049.0
1977	1,437,361	983,686	12,935.0
1978	1,760,019	1,205,625	14,113.0
1979	1,749,931	1,187,857	13,722.0
1980	2,345,000[b]	1,724,000[b]	14,000.0[c]
TOTAL	13,381,317	9,324,535	97,620

[a]Plant operating only part of year.

[b]Last 3 months projected from past years.

[c]Estimated.

regulation. Operation and maintenance costs are roughly half (or less) of those required for equal capacity fossil-fueled plants. The Blenheim-Gilboa Plant has been such a flexible economic addition to the Authority's system that it has applied for a license to construct a similar facility in the same watershed to meet expanding peak load responsibilities. The proposed Breakabeen/Prattsville Project is discussed in the following case study.

2.3.6 Case Study—Breakabeen/Prattsville Pumped Storage Projects

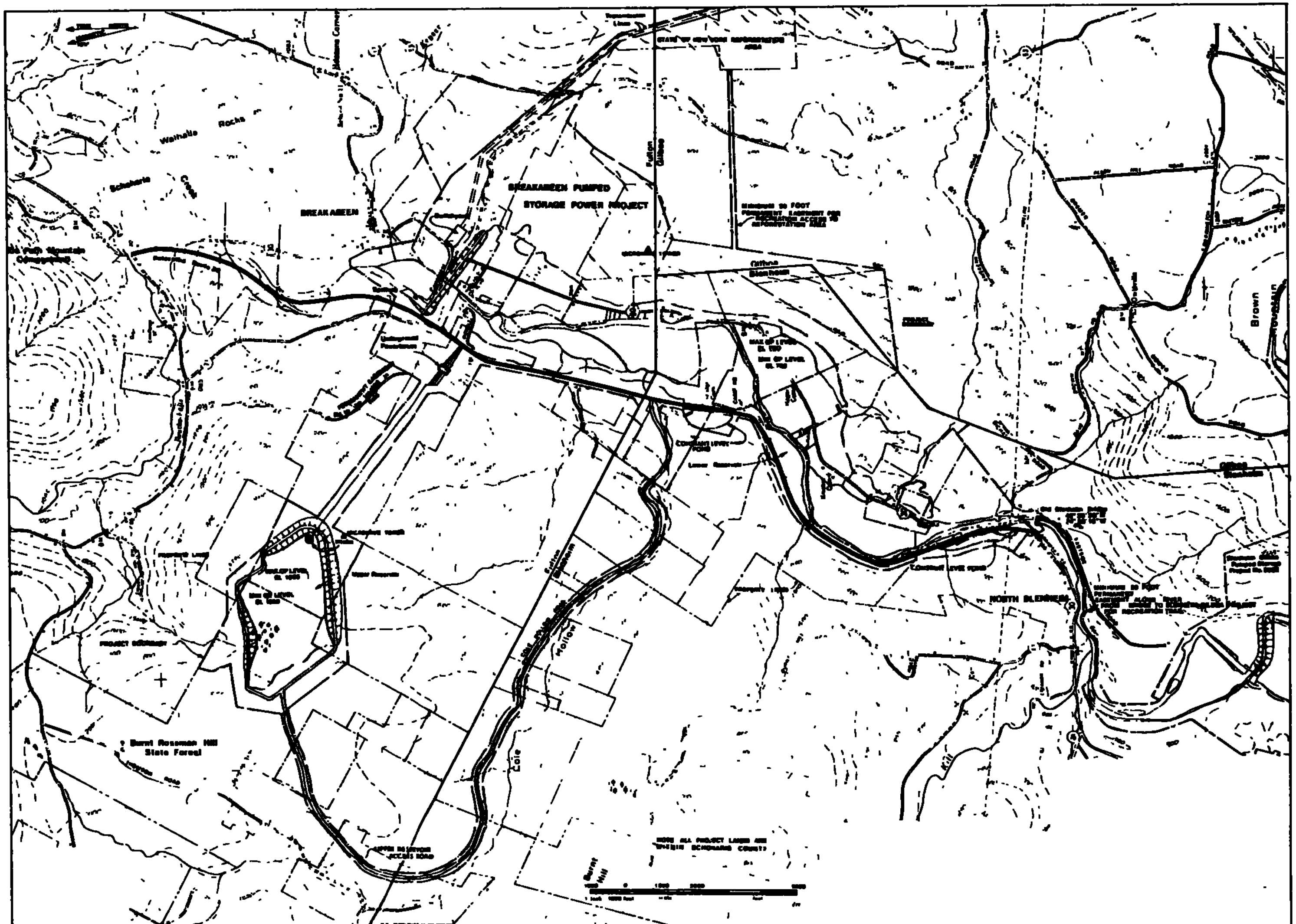
2.3.6.1 General

The Breakabeen Project, proposed in March 1973 by the Power Authority of the State of New York, would have been located immediately downstream of the Blenheim-Gilboa Pumped Storage Project that was under construction. Figure 2-11 is a plan view of the project and its vicinity. Like the Blenheim-Gilboa Project, it would have included a new dam on Schoharie Creek (just upstream of the town of Breakabeen) and construction of a new upper reservoir on Rossman Hill approximately 1,200 feet above the lower pool. The project would have required about 3,300 acres of land, about 2,000 acres would be covered by the upper and lower reservoirs and dams and about 90 acres would be required for relocation of State Route 30.

The Breakabeen Project would have supplied an additional 1,000 MW of generating capacity via four reversible pump/turbines in an underground powerhouse and three 345-KV transmission lines each 4.5 miles in length. The upper and lower reservoirs would have usable storage volumes of 11,900 acre-feet each. Maximum drawdowns of the upper and lower reservoirs would have been 65 feet and 4 feet, respectively. The lower reservoir would have been created by a 75 foot high, 2,800 foot long earth and rockfill dam across Schoharie Creek. The powerhouse, penstocks, and tailrace would have been constructed underground.

The project would have included approximately 1,200 acres of land for recreation use and for the protection and enhancement of scenic and environmental values. The proposed recreation plan included: an all seasons outdoor recreation area; an information center located at an existing roadside rest area on Route 30; two new roadside rest and shorefishing areas on the section of Route 30 to be reconstructed by the New York Department of Transportation; two constant-level ponds, also along the section of Route 30 to be reconstructed; a recreation facility development in the Old Blenheim Bridge area; a hiking trail to connect the proposed major recreational facilities of the project with existing Mine Kill State Park; an easement from the project boundary to the State reforestation area, located east of the lower reservoir, for use by snowmobiles and skiers; and a temporary visitors overlook.

As part of the project the Authority planned to maintain a summer flow in the Schoharie Creek equal to the flow entering the reservoir from tributaries and



SOURCE Power Authority of the State of New York

FIGURE 2-11
PHYSICAL LAYOUT
BREAKABEEN PROJECT

the upstream end. During low-flow periods streamflow was to be augmented by reservoir releases.

2.3.6.2 Rationale for Development

The Power Authority of the State of New York and seven private utilities comprise the New York Power Pool (NYPP) that was formed to coordinate, plan, and operate power facilities throughout the state. The New York Public Service Commission requires that all suppliers assist any area where there is a power shortage through interconnections that tie all systems in the State together. As a result, all of the capacity in excess of that required to serve a utility's direct load is committed by contract to supply the load of other members of the NYPP.

Need for the Breakabeen Project to supplement the existing capacity of the Authority was based on two factors: first, at the time of application the Authority's projections indicated that by 1975 the on-line generating capacity of the Authority would be 4,200 MW. At the same time, the load responsibility was projected as 4,118 MW including both direct and indirect sales. The resulting reserve margin of 82 MW was only two percent of the peak demand experienced in 1974. The New York Power Pool had determined, however, that a 20 percent reserve margin was necessary to meet possible contingency situations in the system. The NYPP projected that without the Breakabeen Project (or equivalent) the net reserve margin could not be met through 1988.

The second factor indicating the need for additional peaking capacity was the deferral or cancellation of other projects that would have met summer generating requirements. An April 1, 1974, report by the Regional Electric Reliability Council projected a 17 percent reduction in planned generating capacity for 1983 for the NYPP service area. Other factors affecting the need for the project were also considered, including effects of conservation and rate revision on electric demand. It was concluded in the draft Environmental Impact Statement (FPC, 1976) that energy conservation during 1973 had produced a drop off in electric demand as a result of the Middle East oil embargo, but that this was short lived as evidenced by the rapid return to pre-embargo levels after correcting for the mild economic recession of that period. When coupled with projections of recovery from the economic slump, it was concluded that concerns regarding electric power shortages were valid, particularly in the light of the delay or cancellation of scheduled additions as previously mentioned.

In addition, after an analysis of the potential for demand reduction through rate revision, it was concluded that:

> "By the year that the Breakabeen Project is scheduled for completion (1981), PASNY will have had sufficient time to study and implement time-of-usage tariffs. Given the current belief that peak-period electricity demands are responsive only to certain types of tariff increases that require improved metering, and because of the time lag that would occur before customers would respond significantly to higher peak-period tariffs, it appears unlikely that rate revisions during the next 5 years would affect the need for the generating capacity that would be provided by the Breakabeen Project." (FPC, 1976, p. 8-9)

Alternatives to the Breakabeen Project which were considered feasible included conventional hydroelectric power, simple-cycle combustion turbines, heat-recovery combined-cycle combustion turbines, and coal fired steam peaking and intermediate load plants. In addition, other sites for pumped storage projects were considered, including the Prattsville site upstream from both the proposed Breakabeen Project and the existing Blenheim-Gilboa Project on Schoharie Creek. A review of the potential conventional hydroelectric sites available in New York State concluded that there were no remaining sites suitable for development providing a comparable alternative to Breakabeen.

Economically, the comparison of alternatives indicates that all the options were within 1.2 percent of the Breakabeen cost estimate. This is well within the range of uncertainty of the estimates themselves. These estimates include capital, annual, and production costs. With regard to sophistication of engineering required for the project, it was considered only moderately complex with the uncertainty about subsurface rock conditions potentially posing the most technically challenging problem.

The main focuses of attention on the Breakabeen Project were the projected environmental impacts. Approximately 600 acres of high value farmland would have been lost to production and about 90 acres of prime forest land taken. Also, in addition to water and air quality impacts during construction, possible long-term changes in water quality were envisioned including temperature changes which could potentially have caused changes in fish populations. Elimination of wintering areas for hundreds of deer and destruction of resident wildlife populations in the areas of the reservoirs were predicted. The project would have impacted three sites listed in the National Register and would have destroyed a fourth site that was eligible for inclusion. Three existing and two proposed archaeological sites would have been inundated. Positive impacts on the local employment and income levels were seen to be short-term in nature.

Although the above environmental issues were not formally publicized until the Draft Environmental Impact Statement (EIS) was issued in April 1976, it was apparent to the Authority that environmental opposition to the project was significant. After the application for license was made in 1973, well over 50 interventions were filed with the FPC. As a result of the considerable opposition, Governor Carey issued on May 15, 1975, a press release stating that the Authority would undertake a comprehensive study of alternative sites within the Schoharie Creek watershed. The possibility of using the existing Schoharie Reservoir along with construction of an upper reservoir on Dog Hill upstream of the existing Blenheim-Gilboa Project on Schoharie Creek was mentioned by the Governor as an attractive alternative. This alternative, known as the Prattsville Project, was presented by the Authority to the Federal Power Commission about a year later as the recommended first alternative to Breakabeen; and one which the Authority believed to be more environmentally acceptable for development. As a result, Breakabeen became an alternative to the Prattsville Project, the history of which will be discussed below.

2.3.6.3 Description of Prattsville Project

On April 28, 1976, the Power Authority requested a revision of its Breakabeen license application for permission to construct, operate, and maintain the Prattsville Pumped Storage Project further upstream on Schoharie Creek. The Breakabeen Project was thus to be an alternative to the newly proposed Prattsville Project.

The Prattsville Project would be located about 6.5 miles upstream of the Breakabeen Project. Figure 2-12 shows the proposed location of the facilities. The existing Schoharie Reservoir, originally built as a water supply reservoir to serve New York City, would be used as the lower reservoir for the project. The reservoir is formed by the Gilboa Dam, a 180-feet earthfill embankment which would be raised 10 feet to provide a usable capacity of 60,000 acre-feet with a 70-foot drawdown. The lower reservoir would continue to act as a water supply for New York City via Shandaken Tunnel which exits from the west side of the reservoir. The upper reservoir would be constructed on Dog Hill and have a live storage capacity of 26,000 acre-feet. It would also serve as a water supply source

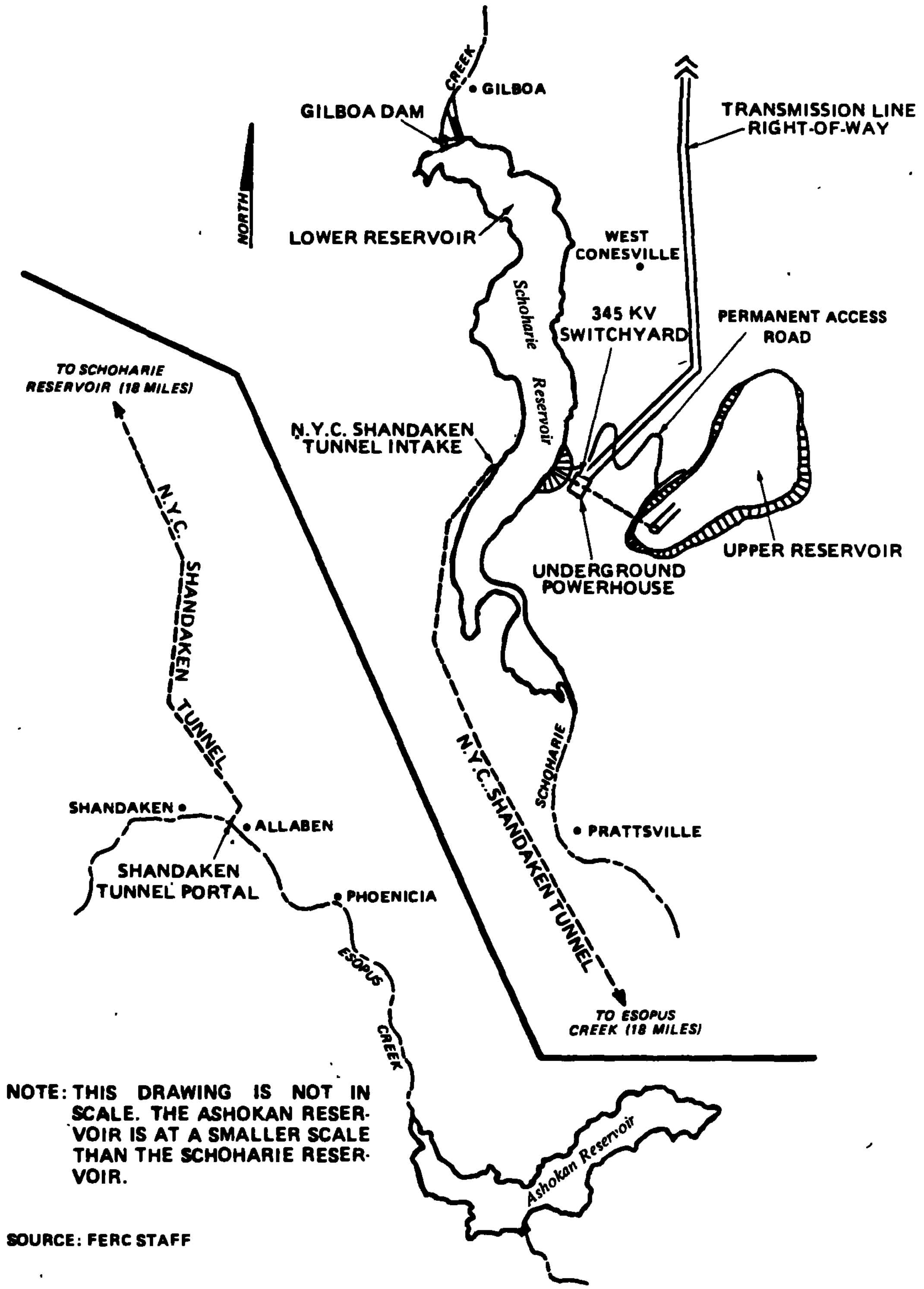


FIGURE 2-12
PHYSICAL LAYOUT
PRATTSVILLE PUMPED STORAGE PROJECT

for the plant and recreational facilities at the project. The penstocks, powerhouse, and tailrace would be underground as proposed for the Breakabeen Project.

The Prattsville Project would require about 3,300 acres most of which is owned by New York City. Over 1,900 acres would be used for the upper and lower reservoirs and associated dikes. Three, 345-KV transmission lines would extend from the project switchyard about 5.6 miles to the existing Gilboa-Leeds transmission line.

The powerhouse would contain four 250-MW vertical shaft, reversible, Francis-type pump/turbines each with a pumping capacity of 372,000 horsepower.

The Prattsville Project has essentially the same objectives as the Breakabeen Project:

- To provide 1,000 MW of fast-response peaking power,
- To provide emergency response capacity,
- To improve system reliability, and
- To displace less efficient, more expensive generating units, such as combustion turbines.

Although the last three of the above objectives are "real" benefits of a pumped storage project, the Prattsville Project, like Breakabeen, had to be justified by analysis of the future need of the New York Power Pool for additional peaking capacity. To do this, increases in electric generating capability of the NYPP had to be projected and acceptable forecasts of peak demand had to be produced. Concerning increases in generating capacity it was noted in the Environmental Impact Statement for the Prattsville Project that delays in the siting and licensing procedure and cancellations of major planned system additions were becoming "epidemic." As an example, in April 1979, the Authority had decided not to construct the 1,200-MW Green County Nuclear Plant. This impacted considerably on Consolidated Edison which is heavily dependent on purchase agreements with the Authority for needed capacity to supply New York City.

On the other hand, peak load responsibility of the NYPP was projected to increase although the rate of increase was the subject of much question. Three projections were developed, each presenting a considerably different outlook on peak demand growth. One forecast prepared for the New York State Department of Environmental Conservation used a disaggregated method to forecast individual load components subsequently summing results into a single projection. The Cornell University Study Group made a second projection using an econometric model. The third was the composite of the individual econometric projections of the members of the NYPP required under Article III, Section 5-112 of the Energy Law of New York State. The latter projections indicated declining growth rates for peak demand although its projections were significantly higher than the two other studies. Because it was a composite of several estimates, the NYPP aggregated estimate was considered to be effective in reducing impact or regional abnormalities. Because of "the considerable forecasting experience and a broader understanding of the unique characteristics of the loads of the eight members of the NYPP" (FPC, 1979, p. 1-116), the higher peak load growth projections were chosen. Using these higher peak demand projections, along with projections of peak load responsibility, the need for Prattsville was apparent.

As with the Breakabeen Project, the effects of conservation and rate revision were considered as a potential factor in need for the project. It was concluded that, while the precise effects of conservation and rate revision on peak load growth were uncertain, the demand and capability forecasts as developed had reflected such effects. It was also concluded that the effects of load management techniques, such as permission for load interruption during periods of peak demand, had been factored into demand projections and were part of the reason for the decrease in peak load growth.

2.3.6.4 Alternatives to Prattsville Project

Alternatives to the Prattsville Project which are considered capable of supplying the type and quantity of the proposed project are:

- Conventional Hydroelectric Power
- Simple-Cycle Combustion Turbines
- Heat-Recovery, Combined-Cycle Combustion Turbines
- Coal-fired, Steam Peaking and Intermediate Load Plants
- Other Pumped Storage Projects (including compressed air)
- Purchase Power.

In the 1976 FPC publication, "Hydroelectric Power Resources of the United States," it was indicated that there were potential undeveloped sites in New York

State which had a total capacity of 1,286 MW of conventional power. However, the largest potential site could reasonably produce only 90 MW and, considering the average capacity of potential sites, about 67 conventional hydro projects would have to be built to yield the capacity of the Prattsville Project. With regard to purchasing power in lieu of developing Prattsville, it was concluded that the alternative was not feasible due to the demand forecasts of the NYPP and resulting lack of available firm capacity. The 800 MW for which the Authority has already contracted with Hydro-Quebec was considered to be the maximum dependable purchase available from Canada.

Of the 96 potential alternative pumped storage projects studied by the Authority at the time of original application for Breakabeen, all but five were eliminated for various economic, technical, or environmental reasons. A sixth alternative site, the Canandaigua site was included by the FPC staff in its review of alternatives for the Prattsville EIS.

An economic analysis of the alternatives to the Prattsville Project indicated that the nine alternatives, including Breakabeen, were within 1.5 percent of the total estimated annual cost of Prattsville for the period 1988-1995. The most attractive non-pumped storage alternative was the cycling coal-fired steam plant which was only 0.3 percent less expensive than Prattsville for the period 1993-1995. Compressed-air energy storage was considered to present too much uncertainty at the time of analysis and was not considered a viable alternative.

With the use of the existing Schoharie Reservoir eliminating the need to flood productive farmland, it was anticipated that environmental opposition to the Prattsville Project would be considerably less than with Breakabeen. This has not been the case. Other projected environmental impacts of construction and operation of the project have resulted in a high degree of interest by a wide variety of individuals and groups. There are now over 70 intervenors on the Prattsville Project. Federal Energy Regulatory Commission hearings on the project are presently being conducted in Washington, D.C. Concerns regarding the effects of the project are directed at a variety of environmental issues, but primarily focus on impacts to local fisheries.

A considerable amount of water is diverted regularly from Schoharie Reservoir through Shandaken Tunnel to Esopus Creek for ultimate use in the New York City water supply system. From 1965 to 1975, such diversions provided from 41 to

83 percent of the flow in Esopus Creek. As a result of the stratification of Schoharie Reservoir, these diversions have been of lower temperature than the flows from the Esopus watershed and, as a result, have acted as a temperature regulator during summer months in Esopus Creek preserving the trout habitat of the creek. As a result of the destratification of Schoharie Reservoir during drawdown and pumping cycles in summer, the temperature regime of Esopus Creek would be altered, possibly damaging the trout habitat. Analysis of the potential for such effects is a technically complex problem and has resulted in a considerable loss of time during study and restudy of the problem. Other impacts on wildlife, water quality, and local social and economic conditions are possible but appear to be secondary to the above concern. The outcome of the hearings and resulting prospects for construction of the project are uncertain at present.

2.3.6.5 Summary

A review of the Blenheim-Gilboa, Breakabeen, and Prattsville Projects provides a significant perspective into prospects for licensing and constructing pumped storage facilities. A chronology of the development of the Blenheim-Gilboa Project is presented in Table 2-5 of Section 2.3.5. From this it can be seen that the elapsed time from the date of license application until licensing and start of construction was 10 months. It was constructed on schedule and is a major contributor to the NYPP electric system capability. The project is in the same watershed as the Breakabeen and Prattsville Projects, required the construction of two reservoirs and had an above-ground powerhouse. However, the Blenheim-Gilboa Project was planned and licensed before the National Environmental Policy Act and an Environmental Impact Statement was not required. In contrast, Table 2-7 shows the chronology of the attempts to license the Breakabeen or Prattsville Projects. In comparison to Blenheim-Gilboa, it has been seven and one-half years since license application for Breakabeen was made and approval is still uncertain. During this period the estimated construction cost for developing the 1,000 MW of additional capacity has risen from $397,800,000 (1973) to $497,588,000 (1980). The delay has occurred for environmental reasons even though the Prattsville Project uses an existing reservoir, has an underground powerhouse, and is in a less sensitive area with regard to historic and archaeological impacts.

TABLE 2-7

Chronology of the Breakabeen/Prattsville Project

1971	Initial planning for Breakabeen begun
March 30, 1973	PASNY applied for FPC license for Breakabeen
April 9, 1976	Breakabeen draft EIS prepared by FPC
April 28, 1976	PASNY requests revision to license application to allow construction and operation of Prattsville Project
May 26, 1977	License application revised to include Prattsville as proposed project with Breakabeen as an alternative
July, 1979	Prattsville final EIS issued
December 1979	Hearings for Prattsville Project begun

2.4 Summary--Major Factors in Pumped Storage Development

When it is considered that the pumped storage capacity in the United States in 1960 totalled less than 100 megawatts in four small projects, the progress that has taken place since that time is outstanding. On November 1, 1980, 31 projects with a total of 13,406 MW were in operation, 11 projects with a total capacity of 9,346 MW were licensed and/or under construction and seven projects with a capacity of 10,150 MW had official Federal or licensing status. This is a total of 49 projects with a capacity of 32,902 MW. In comparison, as of January 1, 1978, developed conventional hydroelectric power in the United States totalled about 59,000 MW (DOE, 1979). An additional 23 pumped storage projects with a total capacity of 32,478 MW have been studied and abandoned or deferred for various reasons. Figure 2-13 illustrates the progress in completing pumped storage plants over the last 30 years and Figure 2-4 (p. 12) shows the total installed capacity of these facilities. Figure 2-14 relates the capital construction costs to the initial operation date for each plant.

The "boom" period of pumped storage in the 1960's continued into the decade of the 1970's with an indication that many large-capacity, 1,000- to 2,000-MW projects would be constructed. For a number of reasons most of these projects were abandoned or placed in a deferred status (Table 2-8). The newly-enacted National Environmental Policy Act, other environmental laws, and the general public awareness of environmental concerns led to widespread opposition to many projects on environmental grounds. Most proponents of projects receiving strong environmental opposition chose to abandon them rather than to risk long and costly hearings and litigation such as were being experienced with the Cornwall and Blue Ridge Projects. Another factor was the large cutback in plans for nuclear plants, plants that were being counted on to supply low-cost pumping energy for the pumped storage plants. At the same time, the cost of fossil fuels used in steam-electric plants increased dramatically. Thus, the cost of pumping energy from such plants would be very high. That, combined with high construction costs due to inflation, made it uneconomical to proceed with some projects. Plans for a number of other projects were deferred because projected future load growth rates had decreased substantially. The prognosis for the future of pumped storage will be discussed in Section 2.4.5.

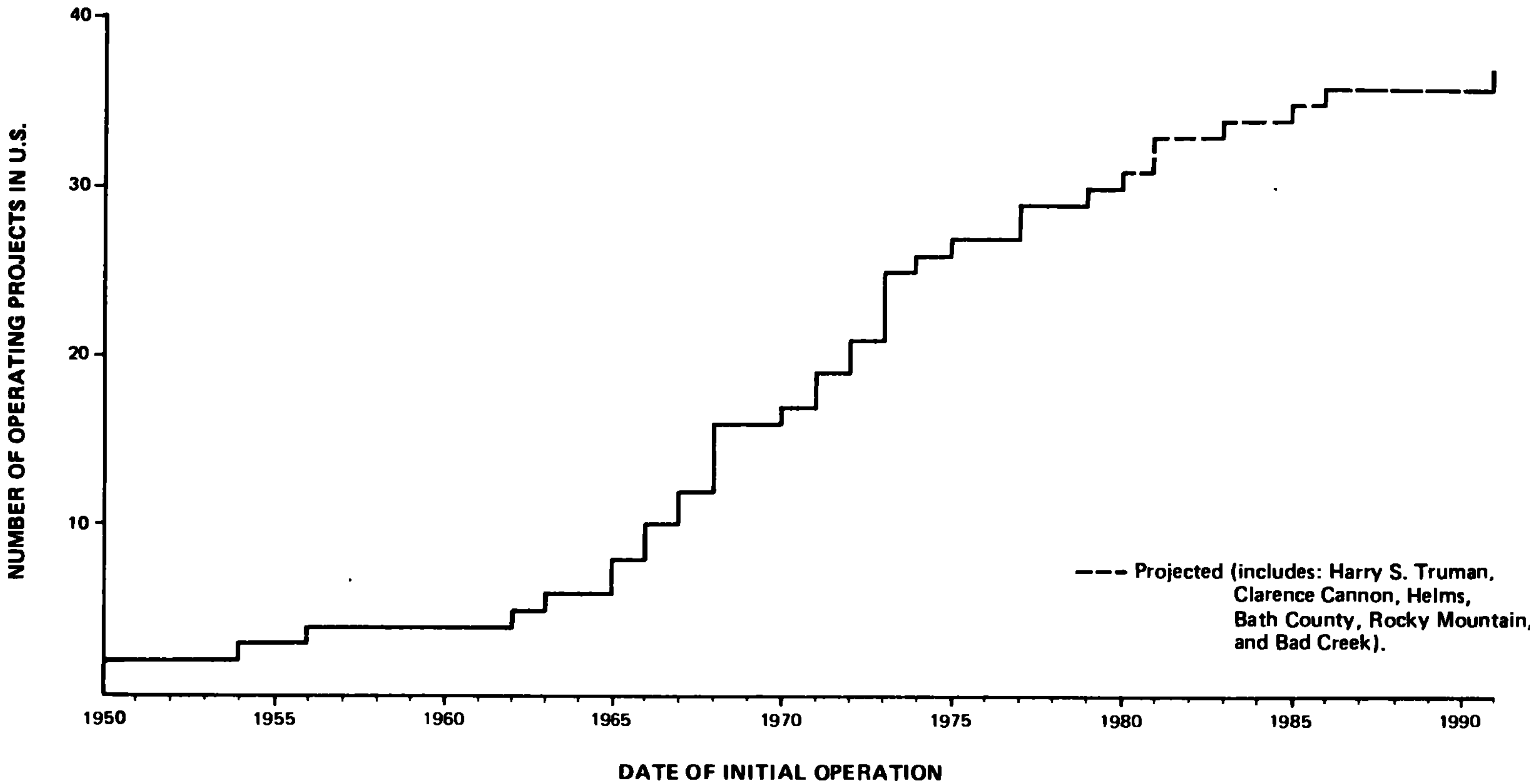


FIGURE 2-13
NUMBER OF OPERATING PROJECTS
HYDROELECTRIC PUMPED STORAGE PLANTS

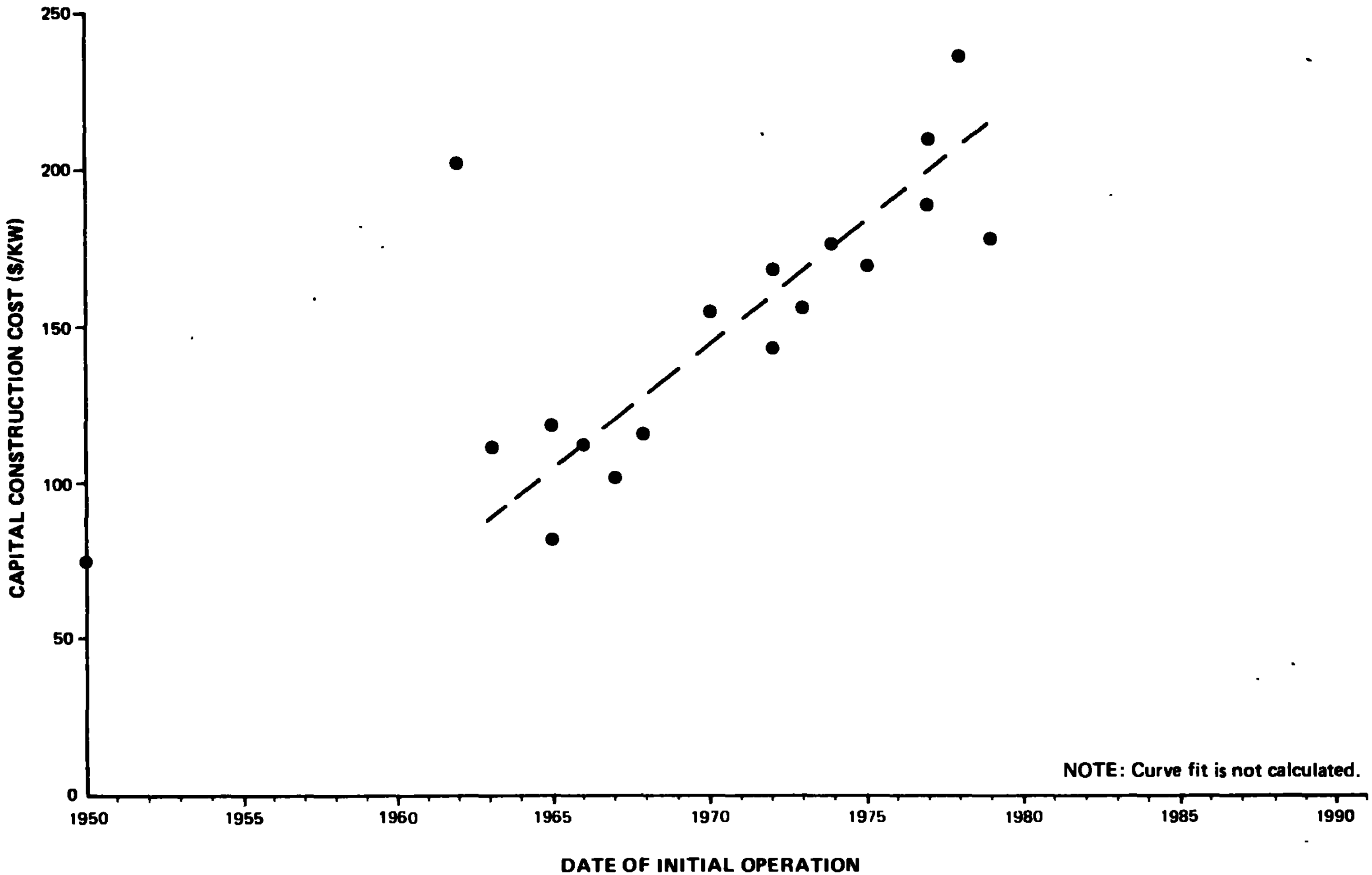


FIGURE 2-14
CAPITAL CONSTRUCTION COST
HYDROELECTRIC PUMPED STORAGE PLANTS

TABLE 2-8

Factors Impeding Pumped Storage Development

- Environmental opposition
- Cancellation of nuclear power plants
- Fossil fuel price increases
- High construction costs due to inflation
- Projection of lower load growth rates

2.4.1 Technological Advances

Although the development of pumped storage projects in the United States is relatively new, the technology is essentially the same as for conventional hydroelectric plants and thus has been available for many decades. The principal difference is the use of reversible pump/turbines at pumped storage projects. Such turbines were available in the 1940's, prior to any significant interest in pumped storage development in the United States.

Probably the major technological advances have been those that led to the production of the single reversible unit that both pumps and generates during successive phases of a plant's cycle. Also extremely important were the subsequent advances made in the size of these units as a result of the ability to operate at increasingly higher heads.

Initially there was uncertainty as to the maximum head that could be developed with single-stage reversible units. The highest head utilized in the United States to date is 1,199 feet at the Cabin Creek Project in Colorado. The licensed Montezuma project in Arizona would have a head of 1,690 feet and four projects--Oak Creek, Blair Mountain, Brown's Canyon, and Mount Hope--all would have heads in excess of 2,000 feet. Single-stage reversible units were planned for each of those developments. The turbine manufacturers have gained experience and confidence in constructing single-stage pump/turbines and they can now be obtained for heads in excess of 2,000 feet.

As a result, the increase in size of pump/turbine generating units has allowed construction of larger plants at only marginally increased costs (see Figure 2-15). The Taum Sauk Project was a leader in this regard. The two 204-MW units installed in 1963 were at that time the largest hydroelectric units in the United States, conventional or reversible. The largest reversible units operating today are the four 382.5-MW units in the Raccoon Mountain Plant. Although the unit construction cost usually is lower for units of maximum size, it is sometimes more valuable to have more units of a somewhat smaller size to provide greater flexibility in operating the plant. A plant with four units, for example, can be operated to bring the units on line one at a time as the system load gradually increases to its daily peak.

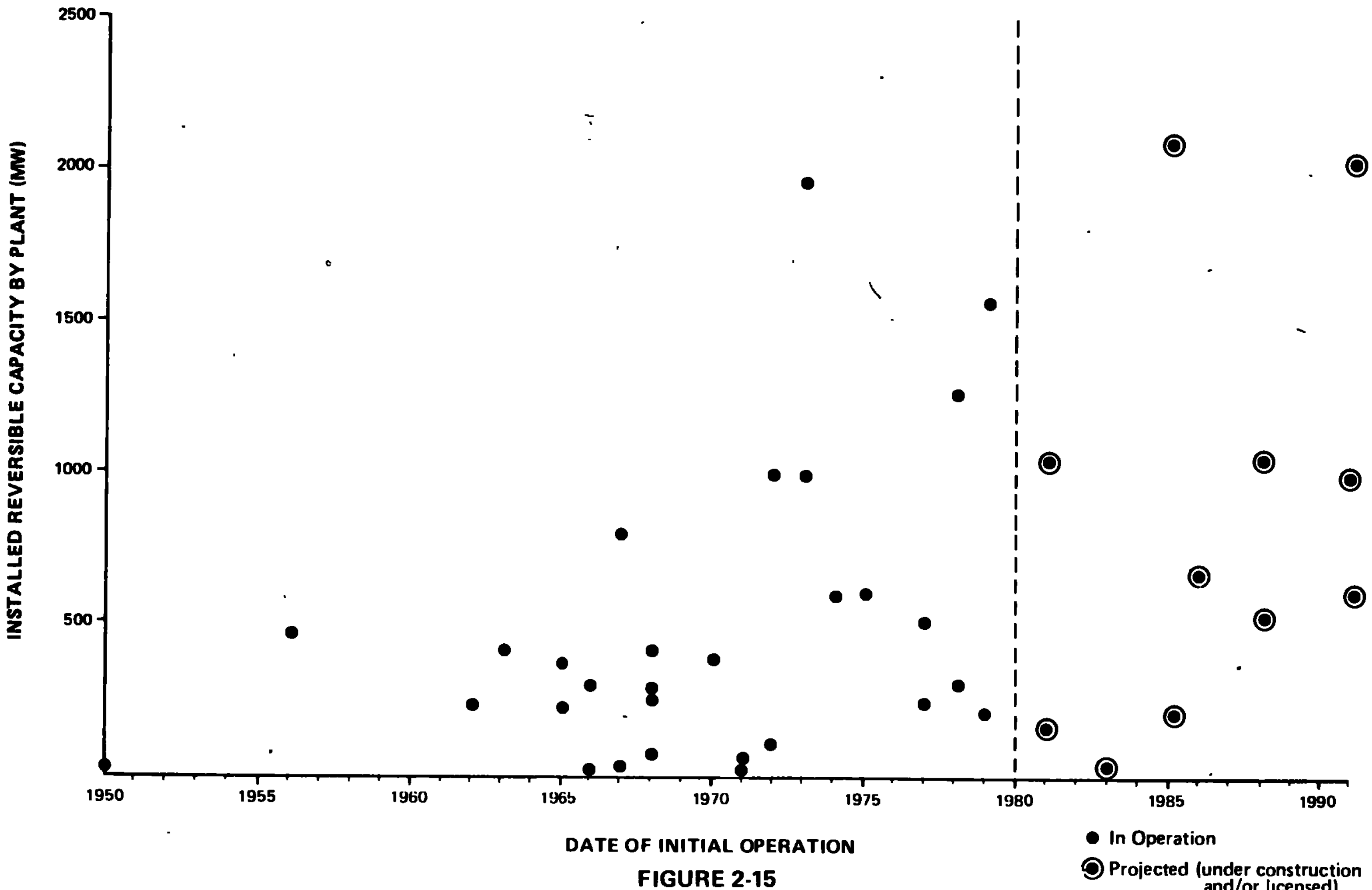


FIGURE 2-15
HYDROELECTRIC PUMPED STORAGE CAPACITY BY PLANT

Advances in blasting techniques, anchoring, and rock stress analysis have resulted in greater confidence with design and construction of underground powerhouses. Advantages of underground powerhouses include:

- More freedom in site selection and plant arrangements
- More freedom in selection of powerhouse elevation
- Reduction in length of penstocks and tailraces
- Economic advantages of cavern powerhouses, shafts and tunnels
- Lessening of environmental impacts (Karadi, 1974).

The same advantages will make underground reservoirs more attractive at future pumped storage projects.

Other technological advances that have affected decisions to build pumped storage plants include:

- Improved overall plant efficiencies resulting from fabricated component design using tempered high tensile steel and stainless steel
- Advances in asphaltic concrete reservoir linings
- Advances in transmission line technology to allow higher voltages to be carried from larger plants with fewer transmission line losses
- Advances in site-selection techniques, such as satellite photography and computer land capability mapping, allowing more advantageous sites to be chosen from a larger number of alternatives.

2.4.2 System Requirements

Even with the above mentioned advances, the fact that a pumped storage plant generally requires 33 to 50 percent more energy to pump than it is capable of generating may still lead one to ask, "Why build a pumped storage plant?" To answer this, the following rationale from a recent Federal Energy Regulatory Commission Environmental Impact Statement is quoted:

> To clarify the logic which makes hydroelectric pumped storage capacity feasible and makes fuel savings possible, an example is offered:

Let us make the assumption* that pumping energy is supplied from base-load units having an average net heat rate of 10,000 Btu per kilowatt-hour delivered to the pumpmotors during off-peak hours. Using a pumped storage cycle efficiency of 75% (a value which is currently attainable), the effective heat rate for energy generated by the pumped storage units becomes 10,000/0.75 = 13,300 Btu per net electrical kilowatt-hour. The "effective heat rate" may be defined as the number from fuel consumed by the base-load plants (which supply pumping energy) in order to obtain one net kilowatt-hour of electric energy from the pumped storage generators.

Up to this point in our example, we have "increased" production costs and have "wasted" fuel. However, if the generation mix of the utility operating the pumped storage plant includes peak-load generating units which have net heat rates exceeding 13,300 Btu/kilowatt-hour, the utility can reduce its fuel consumption and can reduce the fuel component of its operating costs.

The 1975 Department of Energy Data Report entitled "Gas Turbine Electric Plant Construction Cost and Annual Production Expenses 1975" (published May 1978) gives data on the combustion turbines operated by the Consolidated Edison Company (a member of the New York Power Pool). This report shows that the company operated 2,896.8 megawatts of combustion-turbine capacity and generated 1,445 million kilowatt-hours of electric energy with these units. The average heat rate for this total capacity calculated from these data is 15,800 Btu/kilowatt-hour. The heat rates for the 12 individual combustion-turbine plants operated by Consolidated Edison range from a low of 14,700 Btu/kWh to a high of 28,930 Btu/kWh. Forty-four percent of the installed capacity operated at heat rates higher than the average value given above. Modern utilities employ economic load dispatching methods which would result in off-loading the combustion turbine having the highest heat rate first with pumped storage generation. To be conservative (economic dispatch of generating units would off-load the highest cost units first) we shall however use the average combustion-turbine heat rate of 15,800 Btu/kWh. Proceeding in this manner, we see that for every kilowatt-hour of energy generated by the pumped storage plant to off-load combustion turbines, we save (15,800 - 13,380) = 2,420 Btu of fuel oil or gas and the equivalent fuel cost. This represents a minimum of 15.3-percent saving in fossil-fuel energy. If the pumping energy is derived from coal rather than oil, the saving in fuel cost, expressed as a percentage, will be:

$$\frac{15.3\% \times (\text{cost/million Btu}) \text{ for coal}}{(\text{cost/million Btu}) \text{ for oil}}$$

which is approximately 26%.

---

*The average heat rate for the 4,290 megawatts of Consolidated Edison's fossil-fueled base-load capacity at Arthur Kill, Astoria, and Ravenswood for 1975 was 10,036 Btu/kWh - as reported in DOE/EIA -0033/1 for that year.

In addition to the savings in fossil fuels and production costs illustrated by the above example, there are other financial benefits which accrue from pumped storage capacity and which are unique to this form of generation: (1) when large fossil-fueled units must be maintained at hot-bank in order to be quickly brought on line to meet the next day's increased demand, irreplaceable fuel is consumed without returning electric energy to the utility system. In lieu of hot-bank stand-by, such units may be operated at full-load and maximum efficiency to supply pumping energy to pumped storage plants, thus saving the non-productive fuel consumption and costs of hot-bank operation. (2) Operation of fossil-fueled units at minimum load, to provide spinning reserve capacity and insure a stable boiler fire, also increases fuel consumption and costs. Instead of operating at the minimum load required for maintenance of stable boiler fire these units may be operated at maximum efficiency to supply pumping energy when the generation mix includes sufficient pumped storage capacity. This has little effect on the speed of response when the capacity of the fossil-fueled units is required for emergency demand since the pumping load can be instantly tripped, making the pumping load capacity immediately available to meet the emergency demand. (3) Pumped storage units are an economical source of spinning reserve capacity and reactive kilovolt-ampere capacity. The large pumped storage generators may be operated in the spinning-on-air mode as motors but operating in the generator sense of rotation to supply wattless reactive volt-amperes to the system for power-factor correction and voltage control. When operated in this manner the only power supplied by the system are the small losses in the pumped storage unit. Since the turbine runner is spinning in air its losses will be much lower than when operating in water. In less than one minute the air can be replaced with water and generator operation can begin (FERC, 1979).

In summary, although pumped storage plants provide reliability, flexibility, spinning reserve, and voltage regulation, actual justification of the plants has been (and will be) based primarily on net savings in total annual production costs for an entire system when compared to alternatives to pumped storage. Over the last 30 years pumped storage has done very well in the comparison.

2.4.3 Operational History

Part of the reason for the success of pumped storage has been its low operating costs relative to other peaking options. Table 2-9 presents a summary of annual expenses estimated by the Electric Power Research Institute (EPRI) in 1976. Costs for thermal energy storage systems and fossil-fired steam plants with equal power ratings were \$3.20/kW/year or twice the average of the five plants listed in Table 2-9 (excluding Kinzua, which had recognized unusual maintenance requirements). Although these costs are out of date, the relative difference is of importance.

TABLE 2-9

Operating Cost Experience of Hydro Pumped Storage Plants

Plant	Years of Operation	Capacity MW	Adjusted Annual Expenses, $kW/Year Operation	Maintenance	Total
Yards Creek	9	330	0.36	0.78	1.14
Cabin Creek	7	280	0.97	0.41	1.38
Taum Sauk	11	350	0.28	1.25	1.53
Smith Mt.	9	440	0.56	1.00	1.56
Muddy Run	7	856	0.66	1.15	1.81
Kinzua (Seneca)	4	380	1.09	1.43	2.52
Average (6 plants, unweighted)			0.67	1.00	1.67
Average (without Kinzua)			0.59	0.92	1.51
Blenheim-Giloboa	1	1,030	0.19	0.12	0.31
Jocassee	1	312	0.52	0.07	0.59
Ludington	1	1,675	0.35	0.46	0.81
Northfield	2	1,000	0.86	0.32	1.18

Source: EPRI, 1976

Improvements in machine design and manufacturing and decreased losses in penstocks and tailraces due to advanced design have improved plant efficiencies over the years from an average of about 55 percent in the early 1960's to as much as 74 percent presently. Furthermore, pumped storage plants are fulfilling an increased role in a modern utilities system, often supplying the intermediate load as well as peak demand for long periods each day. Utilization factors up to 25 percent are common for plants that were originally justified at factors as low as 3 to 5 percent.

2.4.4 Environmental Factors

The importance of site selection studies in planning pumped storage projects has been made clear during the last decade. Objections from local citizens and environmental groups, which can cause lengthy delays and cost increases, may be controlled in part through more effective site selection processes. The Helms Project (see Case Study No. 4) is an excellent example of the value of public involvement in the project planning phases. It has been estimated that as much as 75 percent of the delays caused in review of environmental reports for license applications have been caused by insufficient detail in alternative site analyses (Resch, 1975).

Whether or not to use existing reservoirs has been a common question asked during pumped storage project planning. Advantages and disadvantages of using existing reservoirs created for other purposes, such as water supply, conventional hydro or recreation, have been observed over the past three decades and include:

Advantages

- Savings in construction cost
- Minimum disruption of streamflow
- Utilization of existing transmission routes
- Minimum changes in land use
- Reduction of adverse aesthetic impacts
- Minimum effects on terrestrial habitats.

Disadvantages

- Adverse effects on boating and swimming

- Potential bank erosion
- Adverse aesthetic effects of water level fluctuations
- Reduction of benthic organisms
- Effects on temperature stratification
- Adverse impacts on existing sport fishing
- Impacts on fish habitats.

A summary of environmental issues resulting from pumped storage development indicates three main categories of impacts that must be analyzed for both the construction and operation periods of a project. First are ecological impacts, including those described above for use of existing reservoirs. Other possible effects on aquatic and terrestrial species may result from spoil disposal from underground excavations, cutting of access roads, and dam construction. Since aboveground pumped storage plants have by nature been located in more remote, environmentally sensitive areas, the impacts may be particularly important. Second, land use impacts such as flooding of agricultural land, reduction of forest productivity, and both positive and negative effects on recreation must be assessed. Third, cultural impacts such as those on historical and archaeological sites may be critical. The short- and long-term consequences of a project on the local economy must be considered.

In all assessments of the environmental effects of pumped storage, it is important to analyze the projected results of a project in comparison to other alternative actions that produce the same objectives.

2.4.5 Future Directions of Pumped Storage

The 30-year history of significant pumped storage development in the United States indicates that its future will hinge on several key issues:

- Patterns of electric demand--While baseload growth will probably continue to level off, much of the impetus to pumped storage has been due to low load factors, which have, in turn, been heavily influenced by demand from the industrial sector. Projections of extended periods of slow industrial growth will tend to discourage pumped storage construction

- Resurgence of nuclear plant construction--The delay or deferral of nuclear plant construction has already affected planning for pumped storage. Resolution of the problems of nuclear energy will pave the way for the provision of large supplies of low-cost, off-peak power for pumping. The attractiveness of using nuclear plant cooling water reservoirs as reservoirs for pumped storage plants has been recognized already.

- Environmental/regulatory climate--Whether or not a moderation of environmental concern occurs may depend largely on factors such as regulatory reform and the national priorities set as a result of international fuel supply situations. Environmental factors play a key role in project development. The planning period (feasibility studies through construction) for a pumped storage plant presently ranges from 12-15 years. Much of this time is a result of regulatory and environmental requirements. In a period of economic, financial, and political uncertainty such a long period will have a tremendous impact on a utility's plans for capital investment. Regulations covering bonding and bond taxation may have an effect on financial feasibility since most privately-owned pumped storage projects are financed by general obligation bonds (up to 50 percent of project costs have been provided by equity stocks in some cases).

- Technological breakthroughs--Significant advantages and cost reductions may be realized in pumped storage due to:
  - Further increases in operational heads
  - Development of techniques for combining pumped storage with other peaking systems such as compressed air
  - Advances in transmission facilities (such as development of direct current capability) that would reduce costs, allow longer transmission distances, reduce line losses, and allow greater flexibility in locating towers (solid state invertors with 90-percent efficiency are in the development stage)
  - Use of fluids with greater specific gravity than water
  - More economical methods of underground construction.

- Advances in alternatives to pumped storage development (such as synfuels projects with resulting supplies of low-cost commercial grade gas) that could affect gas turbine feasibility may be forthcoming although still several years in the future.

These potential advances will be addressed in more detail in Section 5.

Finally, there may be reason to believe that the economy of pumped storage plants will decrease as more are put on line. In other words, two pumped storage plants in a particular system may not provide twice the benefits of one plant. Of course, answers to the above issues of nuclear and coal generation, technological developments, etc., will determine the actual economics of additional plants on a system-by-system basis.

BIBLIOGRAPHY

An Assessment of Energy Storage Systems Suitable for Use by Electric Utilities, Volumes I, II, & III (Electric Power Research Institute, July 1976).

Bad Creek Project No. 2740-South Carolina: Final Environmental Impact Statement (Federal Power Commission, March 1977).

Bath County Project No. 2716-Virginia: Final Environmental Impact Statement (Federal Power Commission, September 1975).

Bilby, Charles R., "Ludington Pumped Storage Plant-Pumped Storage Theory and Actual Operations in a System," Existing Dams and Pumped Storage (1974).

Bohr, Joseph R., Abundance, Distribution and Community Interactions Demersal Fishes Inhabiting the New Ludington Pump Storage Reservoir, Volumes I & II (Michigan State University, 1978).

Brazo, Dan C., and Charles R. Liston, The Effects of Five Years of Operation of the Ludington Pumped Storage Power Plant on the Fishery Resources of Lake Michigan, Volume 1, 20.1 (Michigan State University, 1979).

Breakabeen Project No. 2729-New York: Draft Environmental Impact Statement (Federal Power Commission, April 1976).

"Draft," Proceedings: Workshop on Water Supply for Electric Energy (March 1980).

EPRI Guide--A directory of Technical Reports and Audio-Visual Materials (Electric Power Research Institute, Spring 1980).

Estimate of National Hydroelectric Power Potential at Existing Dams (U.S. Army Corps of Engineers, 1977).

Forgey, Harry L., "Symposium on the Ludington Pumped-Storage Hydroelectric Generating Station," Proceedings of the American Power Conference, Volume 36 (1974).

Gunwalden, R.W., and A. Ferreira, "Northfield Mountain Pumped Storage Project," Civil Engineering-ASCE (May 1971).

Helms Project No. 2735-California: Final Environmental Impact Statement (Federal Power Commission, November 1975).

Hydroelectric Plant Construction Cost and Annual Production Expenses - 1978 (U.S. Department of Energy, November 1979).

Hydroelectric Power Evaluation (U.S. Department of Energy, August 1979).

Hydroelectric Power Resources in the United States (Federal Power Commission, January 1976).

Karadi, Gabor M., et al., "Pumped Storage Development and Its Environmental Effects," Final Report to National Science Foundation on Project GK-31683 (University of Wisconsin, 1974)

Lehnert, Johannes, and F.P. Robertson, "Bituminous Blanket for Dike at Ludington Pumped Storage Project," Civil Engineering-ASCE (December 1972).

Liston, Charles, et al., Results of 1978 Aquatic Research at the Ludington Pumped Storage Power Plant on Lake Michigan Including Entrainment of Fish and Invertebrates, Turbine Mortalities, Reservoir Residence Periods of Salmonid Fishes, Netting and Hydroacoustic Surveys, and Water Currents, Volume I (1980).

Ludington Pumped Storage Project (USCOLD News Letter, March 1974).

"Ludington Workshop on Environmental Effects of Pumped Storage Power Facilities," Summaries of Presentations (Michigan State University, 1977).

Lull, S. Hale, and Antonio Ferreira, "Northfield Mountain Pumped Storage Project," Proceedings of the American Society of Civil Engineers (November 1968).

Miller, Frank, "A Discussion of Energy Alternatives," Presented Before: The South Columbia River Basin Irrigation District (October 19, 1979).

Missel, Joe E., "Construction Features at Northfield Mountain Project," Existing Dams and Pumped Storage

National Hydroelectric Power Study (U.S. Army Corps of Engineers, 1979).

National Power Survey (Federal Power Commission, 1964).

National Power Survey, Part I (Federal Power Commission, 1971).

Potential Pumped Storage Projects in the Pacific Southwest (Federal Power Commission, 1975).

Prattsville, New York Project No. 2729: Final Environmental Impact Statement (Federal Energy Regulatory Commission, July 1979).

Preliminary Inventory of Hydropower Resources, Volume 6 (National Hydroelectric Power Resources Study, July 1979).

Price, Truman P., Hydroelectric Power Policy (U.S. Department of Commerce, February 1971).

Problems in Redevelopment of Old Hydroelectric Power Dams: Second Report on New England (The Johns Hopkins University, February 1978).

"Problems of Hydroelectric Development at Existing Dams," Interim Report on the Middle Atlantic States and the Ohio Valley (The Johns Hopkins University, 1978).

Proceedings, Clemson Workshop on Environmental Impacts of Pumped Storage Hydroelectric Operations (U.S. Department of the Interior, April 1980).

Pumped-Storage in the Pacific Northwest, An Inventory (U.S. Army Corps of Engineers, January 1976).

Resch, Robert H., and Dan Predpall, "Pumped Storage Site Selection: Engineering and Environmental Considerations," Pumped Storage (1975).

Rocky Mountain Project No. 2725-Georgia: Final Environmental Impact Statement (Federal Power Commission, May 1976).

Scott, Norman L, and C.T. McCreedy, "At Hydro Plant, Value Engineering Saves $600,000," Civil Engineering-ASCE (March 1973).

Stout, James J., "Potential Pumped Storage Projects That would Use Existing Reservoirs," Existing Reservoirs.

Survey of Pumped Storage Projects in the United States and Canada to 1975 (IEEE Power Engineering Society, 1975).

Swiger, William F., et al., "Northfield Mountain Pumped Storage Project: Performance," Pumped Storage (June 1980).

The Magnitude and Regional Distribution of Needs for Hydropower: The National Hydropower Study, Phase I, unpublished manuscript (U.S. Army Corps of Engineers, April 1979).

The Magnitude and Regional Distribution of Needs for Hydropower: The National Hydropower Study, Phase II, unpublished manuscript (U.S. Army Corps of Engineers, July 1980).

Underground Hydroelectric Pumped Storage: An Evaluation of the Concept (Main, November 1978).

Warnock, J. Gavin, "Milestones in Pumped Storage Development," Pumped Storage (American Society of Civil Engineers, 1974).

Whitehead, Carl F., and Donn M. Ruotolo, "Ludington Pumped Storage Project Wins 1973 Outstanding CE Achievement Award," Civil Engineering-ASCE (June 1973).

GLOSSARY

Black start--Commencement of generation from a standstill or pumping mode without power from generating sources other than the pumped storage plant itself.

Capacity--The nameplate capacity (installed capacity) of a generator or set of generators.

Capacity factor--The ratio of the average load to the plant capacity assuming a maximum number of hours available to generate on a daily or weekly basis. It is a measure of plant use relative to generating potential.

Conventional hydroelectric generation--Production of electric power from an on-stream plant which stores and utilizes flows without capability to pump water into the reservoir.

Efficiency--The ratio of total power generated to total pumping energy consumed during a complete cycle (daily, weekly, or annually) of a pumped storage plant.

Generator/motor--A single unit capable of generating when operated with a turbine and, in the opposite rotational direction, capable of acting as a motor to supply power to a pump.

Gross head--Simultaneous difference in elevation between water surfaces of the upper and lower reservoirs for a pumped storage plant.

Load factor--The ratio of average load over a given period to the peak load occurring during that period.

Operating head--The simultaneous difference of elevations between the water surfaces of the upper reservoir and lower reservoir with velocity heads across the turbine included.

Reversible turbine/pump--A single unit capable of performing as a turbine which outputs to a generator in one direction of rotation, and, in a short period of time, reverses rotational direction to operate as a pump receiving power from a motor.

Spinning in air--The procedure of allowing the turbine to rotate without engaging the generator.

Spinning reserve--The portion of a bulk electricity supplier's total capacity which is not generating but is kept at reduced speed to allow full generation capacity within a specified short period of time. The capacity of a pumped-storage plant which is not generating is generally considered spinning reserve since it can usually be brought to full capacity within the specified time period.

System support--The operation of turbine/generators in the spinning-in-air mode to provide voltage regulation (condensing) and other advantages to a utility's system while not generating electricity.

Utilization factor--The ratio of energy output to available energy based on the capacity of the plant. It is a measure of plant use as affected by water supply.

3.0 ALTERNATIVES TO HYDROELECTRIC PUMPED STORAGE

3.1 INTRODUCTION

The need to add new generating capacity to the nation's electrical system results from the interaction of a number of factors. These include the characteristics of existing capacity; the current generation fuel mix; the age of the various units; the present level of electricity demand and existing load shapes; forecasts of electricity demand and load shape; forecasts of inflation, including the cost of new generation; the cost of future supplies of fuel; the cost and availability of new capital; the current financial status of the industry; and, of importance to this study, the status and availability of new technology.

This section addresses a specific group of technologies: those that are, or will soon be, alternatives to pumped storage. These alternatives are identified, and their characteristics are discussed. In later sections of this study these new technologies will be compared to pumped storage and their competitive prospects will be assessed, taking into consideration current and future economic trends and their impact on the choice of feasible peaking capacity system additions.

3.2 SUPPLY ALTERNATIVES

3.2.1 Introduction

As our fluid fuel supplies decline, numerous alternative energy technologies are being explored to find ways to meet changing energy demands. Little effort has been made, though, to analyze the specific characteristics and attributes of competing technologies that could provide substitutes for the oil and gas being used in today's peaking electric generating units. One potentially important substitute is hydroelectric pumped storage, already in use in many regions of the United States, and the principal focus of this study.

There are several competing technologies available today and others that are likely to become available within the 20-year time-frame of this study. Some of these may offer certain potential advantages to electric utilities; thus, an assessment of the supply technologies competing with pumped storage and the attributes important to decisionmakers is necessary in order to determine factors affecting competition, geographic areas where pumped storage is competitive, and potential supply competitors to pumped storage.

In this section and in Appendix B, the supply alternatives are analyzed as follows:

- A full list of candidate alternatives is developed
- Screening criteria are developed to determine which candidates are available and applicable as alternatives to pumped storage
- The criteria are applied to the full list of candidates in a preliminary screening to yield a short list of alternatives to hydroelectric pumped storage
- Attribute criteria are developed for assessment of the screened list of alternatives (Figure 3-1a)
- A detailed description and an assessment of the screened list of alternatives are performed.

Specifically, the screening, assessment, and characterization of the alternatives presented in this section form the basis for the comparative assessment presented in Section 4 and a key part of the analysis of the potential for development presented in Section 5.

3.2.2 Supply Alternatives Methodology

The full list of candidate supply technologies considered is listed in Table 3-1. These are technologies that might be used now or in the future to meet a projected level of demand. The categorization of these alternatives given in the right-hand column of Table 3-1 results from the initial screening process discussed below.

The following criteria were employed in an initial screening of the candidate supply technologies:

- Availability--Will the candidate technology be commercially available before the year 2000?
- Gross Economic Viability--Will the projected energy costs of the candidate technology be in a range offering some reasonable possibility of economic competitiveness before 2000?
- Environmental and Institutional--Are there any major environmental, legal, regulatory, or other institutional barriers to the use of the candidate technology?

FIGURE 3-1a

Characterization Criteria for Supply Technologies

Technological

Operating principles and characteristics
Current status
Research and development requirements
Development outlook, schedules, and targets
Advantages and disadvantages
Summary of technical factors (e.g., peak-load capability, efficiency, capacity factor, lead-time, lifetime)

Resources

Resource requirements
Availability and geographic distribution
Siting considerations

Impacts

Principal environmental and safety considerations

Institutional

Principal legal, regulatory, and other institutional considerations

Economics

Status
Projected, including principal factors affecting viability
Availability and/or estimates of commercialization/market penetration
Summary of economic factors (e.g., capital cost, fuel cost, operations and maintenance costs, typical power costs)

Note: These criteria are used in the detailed discussion of each supply technology.

TABLE 3-1

Initial Categorization of Candidate Alternative Supply Technologies

Storage Technologies	Category*
Hydroelectric pumped storage	A
Utility thermal storage	A
Compressed air storage	A
Batteries	A
Capacitors	C
Flywheels	C
Hydrogen	C
Superconducting magnets	C
Thermochemical pipelines	C
Thermal-Fossil Technologies	
Diesels and combustion turbines--existing fuels	A
--synthetic fuels	A
Oil plant conversion--to coal	B (and C)
--to coal/oil mixtures	B
--to RDF/oil mixtures	B
--to synthetic fuels	B (and C)
Phosphoric acid fuel cells	A
Combined cycle	B
Coal gasification combined cycle	B (and C)
Fluidized bed combustion	B (and C)

*A = Firm peak power generation, available before 2000.
B = Intermediate-load power generation, available before 2000.
C = Base-load power generation and/or not available before 2000.

TABLE 3-1 (cont'd)

	Category
Solvent refined coal	C
Gasifier/molten carbonate fuel cells	C
Magnetohydrodynamics (MHD)	C
Cogeneration	B (and C)
Bottoming cycles	C
Thermionic conversion	C
Other Thermal Technologies	
Geothermal	C
Solid wastes	C
Advanced nuclear--converters	C
--breeders	C
Renewable Technologies	
Hydroelectric--expansion of existing facilities	A, B, and C
--installation of unpowered dams	A, B, and C
--new dams	A, B, and C
Solar photovoltaic--terrestrial	A (and B)
--satellite	C
Solar thermal	B
Wind	B
Tidal	B
Wood and other biomass	B (and C)
Ocean thermal energy conversion	C
Waves	C
Currents	C

- Applicability--Can the candidate technology reliably provide firm peak capacity? If not, can the candidate technology otherwise impact on peak and cycling electricity production in a manner that might compete with pumped storage?

Figure 3-1b depicts the specific way in which these criteria are used in the initial screening process. Of the four criteria, the first and fourth perform most of the screening function. The second and third play only a small role; only major barriers are considered here. Consideration of environmental impacts and institutional factors is taken up in the discussion and characterization of candidate technologies that have passed the initial screening, and in their comparative assessment with pumped hydroelectric storage; more detail on each of the technologies also appears in Appendix B. Similarly, detailed consideration of economic competition is covered in the analysis presented in Section 5.

The first of the criteria operates here in a "yes/no" sense for initial screening. A specific availability schedule is discussed for those technologies that are not commercially available today but that are expected to be available before the year 2000. Another criterion that must be considered is regional availability, affected, for example, by resource constraints at the regional level.

The initial screening process sorts the full list of candidate technologies into three basic categories:

- Category A--Technologies that will probably be commercially available within the study time-frame (1980-2000), and that are direct alternatives to hydroelectric pumped storage in the sense of being capable of providing firm peak-load capacity.
- Category B--Technologies that are likely to be commercially available, and that, although not direct alternatives, could otherwise impact on peak and cycling electricity generation in a manner that might compete to some extent with hydroelectric pumped storage production. Specifically, this category incorporates available intermediate-load and certain fuel-saver technologies (the latter being technologies whose effective capacity is much lower than their rated capacity).
- Category C--Technologies that are not expected to be commercially available in the study time-frame, and/or that will be used for base-load rather than peaking power generation.

Figure 3-1b Initial Screening Process for Alternative Supply Technologies

1.

2.

3.

4.a

4.b

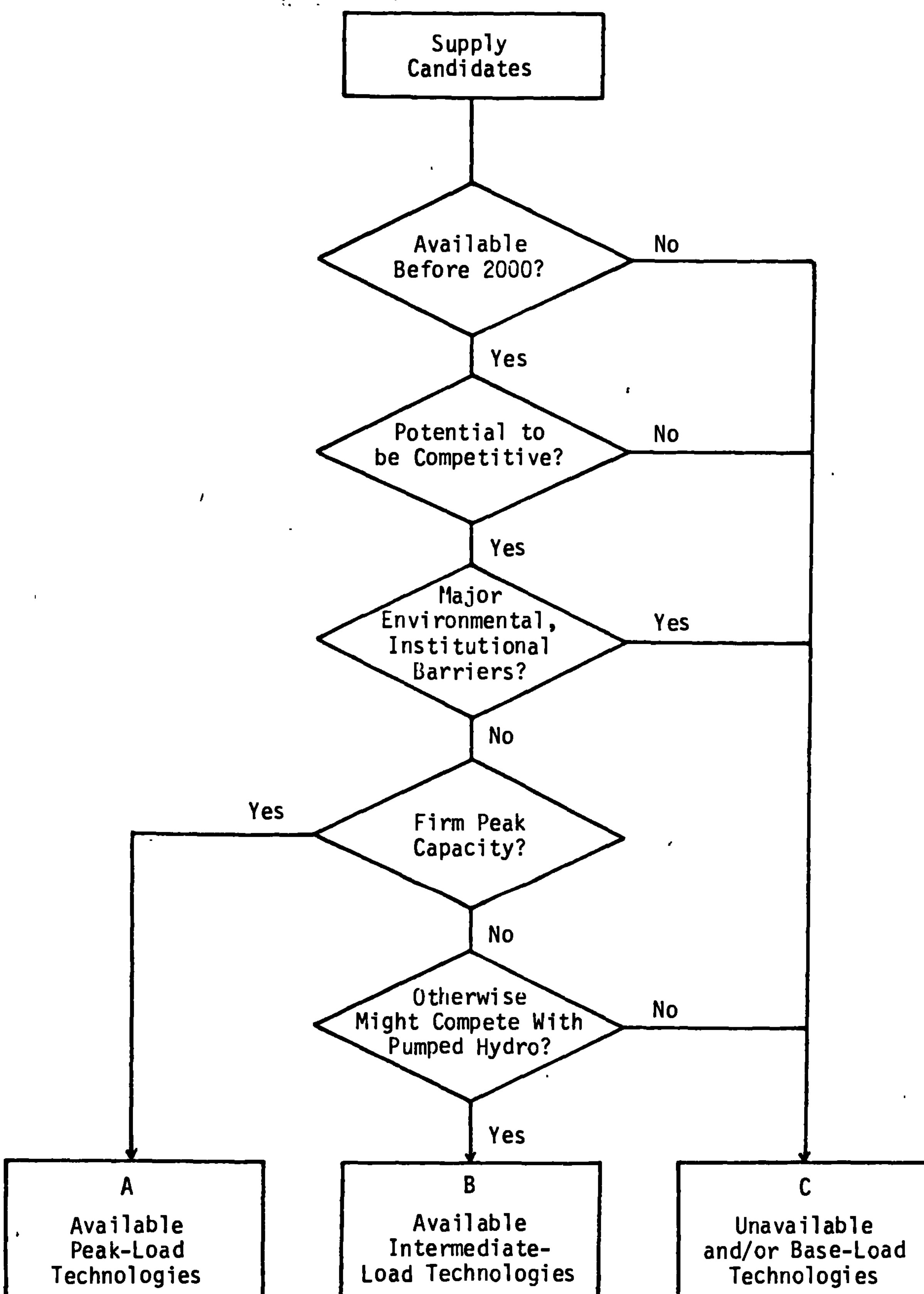


Table 3-1 shows the results of thus categorizing the list of candidate supply technologies using the initial screening criteria. Of the roughly 40 candidate supply technologies (many of which subdivide into several variants), eight have been screened into Category A and will be discussed briefly below. Besides hydroelectric pumped storage these are: utility thermal storage; compressed air storage; batteries; diesels and combustion turbines; phosphoric acid fuel cells; hydroelectric power; and solar photovoltaic energy conversion. Approximately 10 more technologies have been screened into Category B and will be discussed briefly. The remainder, about half of the full candidate list, comprise Category C.

3.2.3 Assessment of Category A Supply Alternatives

3.2.3.1 Utility Thermal Storage

Thermal energy storage (TES) systems are dedicated storage systems designed to be integrated into a utility electric generating plant, storing thermal energy from steam or hot feedwater during low demand periods and releasing it for use in generating electricity during peak demand periods. There are two basic ways to integrate thermal storage into a central base-loading powerplant. One method involves adding a separate peaking turbine to an existing powerplant and the other method uses the stored heat to heat the feedwater and requires a modified turbine design to allow for large variations in the extraction steam flow. During peak load periods, the latter method heats the feedwater from storage, thereby increasing turbine throughflow and power output.

A series of Electric Power Research Institute (EPRI) reports (1, 2) prepared by General Electric identified a number of TES systems and analyzed the most promising for near-term electric utility applications. Of the 40 TES system concepts examined for possible application to two reference plants (an 800-MW high-sulfur coal plant and a 1,190-MW light water nuclear reactor)*, 12 systems were found to be the most promising in terms of near-term availability and potential for economic feasibility. Of these, the TES powerplant with the lowest capital cost and highest overall efficiency used underground cavern storage of high temperature water in steel vessels. Other storage media considered included aquifers, oil, water/steam, and molten salt, and various combinations thereof.

*These plants were chosen since these plant types are expected to represent the majority of utility capacity additions to the year 2000.

These systems are outlined in Table 3-2, including estimated costs in 1976 dollars (see Appendix B for discussion).

Compared to alternative methods of storage, TES systems also offer the potential for efficiency savings. The turnaround efficiencies of the EPRI selections, while somewhat higher than those given in other studies, were roughly in the range of 75 to 85 percent for low vapor pressure systems, and 85 to 90 percent for the high-temperature water systems (2).

None of the TES systems discussed in the report have technical problems substantial enough to prevent their deployment; on the other hand, none of the TES systems appear to be economically attractive to utilities at this time (2). About one-half of the TES costs arise from the storage-related items necessary for water, oil, and molten salt systems, with the remaining costs for standard state-of-the-art equipment such as turbines, piping, valving, etc. Future reductions in total costs, therefore, must come almost entirely from reductions in the TES storage-related expenses (2). While not investigated in the EPRI studies, redesigns of the reference coal and nuclear plants and TES systems also would be required to improve the performance of TES for peaking applications (2), and these changes would eliminate the use of TES in near-term applications. Federal agencies, in addition to EPRI, have been examining the concept of TES (3) and have also reached the conclusion that TES systems are likely to be costlier and less efficient than pumped hydroelectric energy storage.

3.2.3.2 Compressed Air Storage

Compressed air storage (CAS) systems store energy in a form convenient for power generation by pumping compressed air into an underground reservoir. Rock beds, salt domes, and aquifers are all reservoir candidates. During compression, the air gets hotter, requiring cooling to prevent fracturing of the rock or creeping of the salt reservoir in which the air would be stored at about 1,000 pounds per square inch (psi). This constant-pressure system would cool the air to about 50°C (122°F) during storage. During the power generation mode, the stored air would be released and passed through a recuperator (a proposed feature that recovers exhaust heat from the power-generating turbine) and preheated before being channeled through an expansion turbine. The preheated, high-pressure air is then heated further by burning fuel (oil or gas) as the air is expanded into the power generating turbine.

TABLE 3-2

Economic and Near-Term Availability Ranking for Thermal Energy Storage Systems

Selection Number	System	Energy ($/kW)	Power ($/kW)	TOTAL ($/kW)	Economic Rank	Near-Term Availability Rank
1	Prestressed cast iron vessels-feedwater (PCIV-FWS)	461	462	923	6	4
2	Prestressed concrete pressure vessels-feedwater (PCPV-FWS)	524	495	1,019	9	4
3	Steel vessel-feedwater (STEEL-FWS)	1,129	495	1,624	12	1
4	Underground-concrete-variable pressure (UG-C-VARP)	172	477	649	1	3
5	Underground-compressed air-feedwater (UG-A-FWS)	108	667	775	5	6
6	Underground-evaporators (UG-A-EVAP)	180	487	667	2	4
7	AQUIFER	75	855	930	8	6
8	Oil-feedwater (OIL-FWS)	132	538	670	3	5
9	Oil and packed bed/thermocline (OIL/ROCK)	188	541	729	4	3
10	OIL/SALT	---	---	1,400	10	2
11	SALT/ROCK	426	501	927	7	4
12	Phase change material (PCM)	1,000	---	1,500	11	8

Note: Based on 6-hour discharge. Costs are in 1976 dollars.

Source: General Electric Company. *Conceptual Design of Thermal Energy Storage Systems for Near-Term Electric Utility Applications*, Vols. 1 and 2, EPRI EM-1037, Project 1082-1 (Electric Power Research Institute (EPRI), April 1979).

Compared with hydroelectric pumped storage, CAS has several advantages, including a wider choice of geological formations, greater compactness (the density of the energy stored could be higher), and a smaller minimum capacity size. However, because existing CAS concepts use oil or gas in the turbine train, it is not a pure energy storage system, although CAS systems are expected to save as much as two-thirds of the premium oil or gas fuels required by a conventional gas turbine unit. To date, however, there has been limited experience with CAS systems.

CAS facilities must be sited where the geology is such that a suitable air-storage cavity can be economically developed (as noted by Miller (4), studies have shown that the economic optimum is obtained with storage pressures between 600 and 1,000 psi). A literature search has not revealed any detailed analytical survey of potential CAS reservoir candidates throughout the country; however, EPRI (5) reported that favorable geologic conditions in the United States are widespread (Figure 3-2), and it identified potential utility networks and power pools that could be used for CAS salt cavern systems.

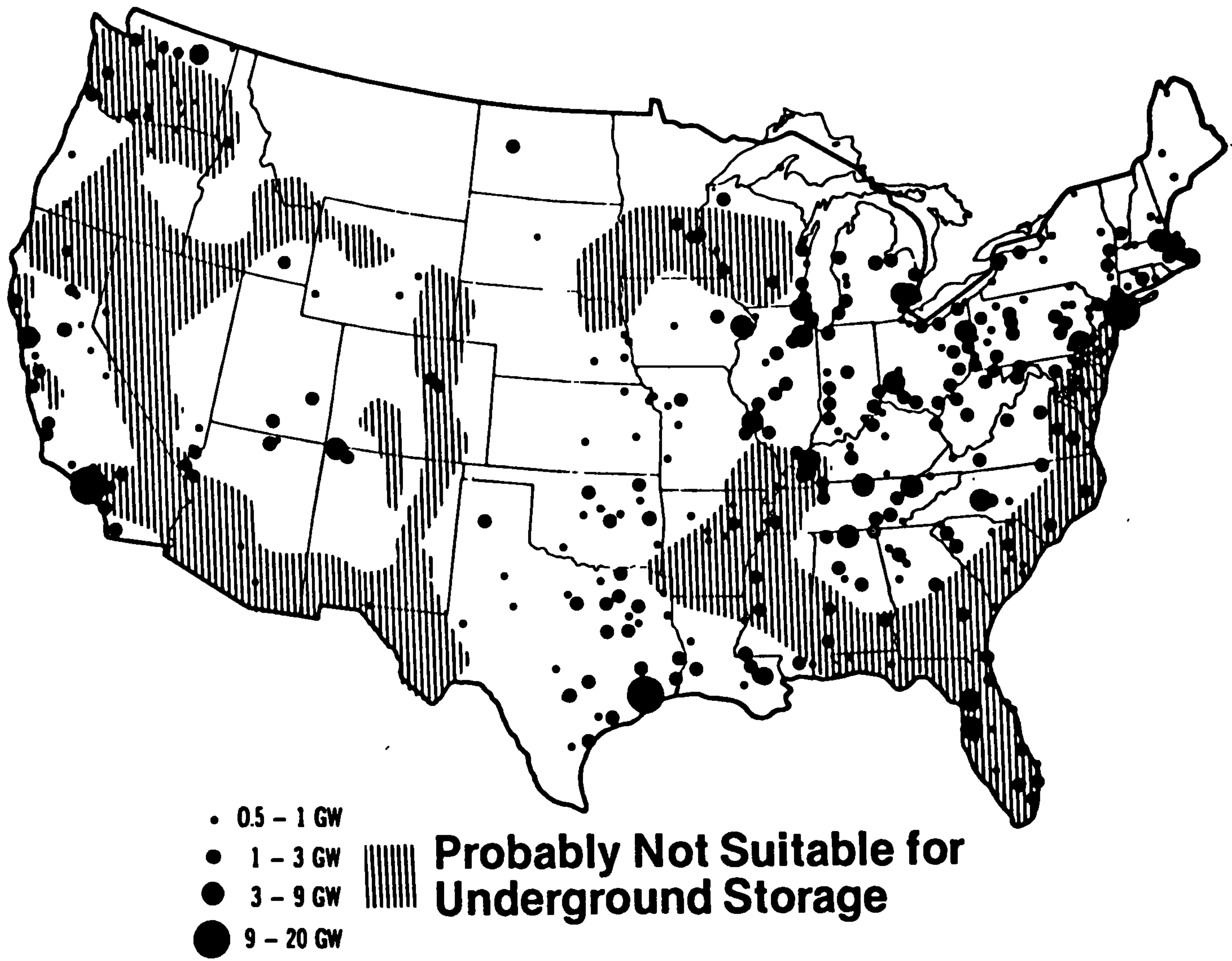
At present CAS is not part of the utility generation mix in the United States, although a 1977 EPRI report concluded there were no major technical or generic environmental barriers to constructing such plants. CAS costs also are "expected to be competitive with that (electricity) generated by underground pumped hydro and certainly less expensive than that produced by a standard gas turbine" (6). No technical or environmental barriers exist, other than those related to siting considerations and to implementing CAS systems as peak power/storage alternatives during the 1980-2000 time frame (7).

EPRI and the Department of Energy (DOE) have cosponsored three preliminary engineering studies to provide bases for design and for decisions by U.S. utilities interested in CAS. Each study focuses on a particular storage medium: salt caverns, rock, and aquifers. The component technologies are largely available, and commercial-size plants (200-500 MW) potentially could be operating in the United States by the mid to late 1980's. Based on the results of these three studies, the Soyland Power Cooperative of Illinois has begun licensing activities for a 400-MW (two-unit), compensated hardrock CAS plant.

3.2.3.3 Batteries

Advanced batteries have the potential to become an attractive choice for daily-cycle energy storage and peaking power because of their modular capacity

Figure 3-2 Principal Electric Load Centers and Regions Probably Suitable for Underground Storage



Source: Reference (5).

and dispersed siting flexibility, their short installation lead time, their rapid and efficient response to load changes, and other advantages such as minimal environmental impact. However, none of the existing, commercially available automotive or industrial lead-acid batteries have the characteristics required for large-scale modern utility storage system application--low costs and long service lives. A new generation of electrochemical battery storage systems now under development for utility service promises to meet these requirements.

In addition to a large number of research and development efforts by private companies, detailed assessments of the technical and economic prospects of the more promising advanced battery prototypes are to be made at the Battery Energy Storage Test (BEST) facility, jointly funded by DOE and EPRI. In order to provide actual operating experience with battery storage coupled to a power grid, DOE and the electric power industry have also initiated the Storage Battery for Electric Energy Demonstration project (SBEED). The current goal of the project is to complete a facility by 1984 consisting of a 30,000-kWh lead-acid battery coupled to a 10,000-kW AC-DC converter connected to the Wolverine Power Cooperative grid in northern Michigan. To be operated by utility employees, the $20.3 million SBEED plant will be used to provide the on-line performance, reliability, and economic data needed prior to utility applications.

Although the potential benefits of advanced battery systems are substantial, these systems will not find significant utility application in this century unless their cost can be reduced to a level competitive with other bulk energy storage and peak-generating methods. EPRI's goal for the battery selling price is just under $300/kW for a 5-hour battery system with power conditioning equipment. Of all the battery systems currently under consideration, only the lead-acid can be listed as a near-term (pre-1985) candidate. Because of its costs, however, significant commercial application by electric utilities is not expected.

Of the several advanced battery systems proposed, the two that appear to be the most promising for utility application before the year 2000 are the high-temperature sodium-sulfur battery and the low-temperature Redox battery. General Electric Company and EPRI have been cosponsoring the development of the sodium-sulfur concept, the determination of technical and manufacturing feasibility, and the evaluation of market potential. Work completed to date indicates that major technical barriers have been overcome, that the system manufacturing costs are potentially competitive, and that the market appears to be large, although significant uncertainties still remain in each of these three areas (8). The Redox (an acronym for reduction-oxidation) battery is under development at the National Aeronautics and Space Administration (NASA) Lewis Research Center in Cleveland, Ohio, under joint NASA and DOE funding. If development programs can keep to schedule and costs can be substantially reduced, these batteries may be commercially available for utility use in the early 1990's.

3.2.3.4 Diesels and Combustion Turbines

Diesels for electric utility application operate on the same principles as their automotive counterparts, though they are much larger and are more ruggedly designed for long operating lives. Likewise, combustion turbines are similar in basic operating principles to aircraft turbojet engines. Diesel- and combustion-turbine-driven generating units already supply a substantial portion of today's peak-load electricity generation.

These units are convenient for a number of reasons. The first is that their cost, per kilowatt of capacity, is the lowest of the conventional forms of generating capacity used by electric utilities. For example, a 75-MW combustion turbine is estimated to cost about $190/kW (in late-1978 dollars) (9), or about one-quarter of the capital cost of a modern coal-fired powerplant. This low capital cost, together with inherent operating characteristics, makes diesel and combustion turbines well-suited to the low-hours operation of peak-load units--although they do use premium oil and gas fuels. These units also have a short lead time for construction and can be put "on line" in approximately 18 months. Since they are available in a range of capacities, blocks of combustion-turbine capacity can be dispersed throughout the utility system in a manner that will locate them near appropriate load centers. This dispersion can reduce transmission line requirements and transmission losses. In most cases, combustion-turbine capacity can be brought to full load in approximately 30 minutes (4).

Those units currently in use burn premium oil or natural gas fuels; however, the Power Plant and Industrial Fuel Use Act of 1978 exempts the use of oil and gas in utility units that operate for less than 1,500 hours a year, or at less than 17-percent capacity factor, which is in the peak-loading range. Hence, diesels and combustion turbines probably will continue to be an important alternative for peak-load electric power generation in the coming decades.

Beyond 1990 it is possible that synthetic liquids and gases may be used in diesels and combustion turbines for peak loading. Since the basic gasification and liquefaction technology is almost two centuries old, these fuels could, in principle, be obtained either by purchase from private (nonutility) producers or by utilities building and operating their own synfuel facilities. If construction of commercial facilities was to begin soon, synthetic fuels could be economically competitive with conventional oil and gas in the 1990's. However, current planning efforts are somewhat limited, in large part due to the high capital investment required.

3.2.3.5 Phosphoric Acid Fuel Cells

Fuel cells are conversion devices that convert the latent chemical energy contained in a fuel directly into electricity. The fuel cell operates in a manner somewhat similar to a battery except that it is designed for continuous operation rather than an operation/recharge cycle. Among its advantages for intermediate-load and peak-load operation are: relatively high efficiency (36 to 46 percent); constant efficiency over a wide load range; clean operation; and the potential for siting close to load centers.

For utility applications, hydrocarbon fuels (synthetic or natural) are preferable, and the production of alternating current (AC) is a must. Therefore, a fuel cell powerplant has three subsystems: a fuel-processing section, the fuel cell, and an inverter to convert the direct current (DC) to AC (10).

The phosphoric acid electrolyte fuel cell powerplant has evolved faster than other fuel cell plants as a result of industrial and utility interest and development (11). Extended fuel cell utilization may not occur, however, until potential users are assured that the systems could operate reliably, not only on highly refined naphtha or natural gas but also on the more abundant, heavier, and lower quality fuels. It is felt that, ultimately, utilization of coal-derived fuels will be required for economical usage of fuel cells (12). This is the focus of research and development on second-generation fuel cells, which were classified as a Category C supply technology.

There are potential drawbacks in using first-generation cells as peakers in that currently available batteries do not have ideal startup and shutdown characteristics (13). Required improvements also are related to fuel cell anode and cathode design, fuel processor catalyst design and removal of impurities, fuel cell integration with the fuel processor, waste heat recovery (efficiency improvement), and reduction of fuel cell corrosion problems (which decrease lifetimes) (10).

There are many organizations working on the fuel cell and its effective application in power generation systems. United Technologies Corporation has undertaken to design and test a fuel cell powerplant, and Westinghouse is currently negotiating to build a 75-MW fuel cell facility and to test it at a host facility. While capital costs for fuel cell application currently are not economically competitive, proponents believe that fuel cells can be commercialized by the mid-1980's at a cost of about $500/kW--about half of what they now cost (an ultimate cost goal of $300/kW has been mentioned). Overall, however, fuel cells offer several advantages as compared to combustion turbines and diesels and could be a viable candidate for peak-load power generation in the future if component lifetimes are increased and capital costs can be significantly decreased.

3.2.3.6 Hydroelectric Power

Hydroelectric power is one of the major sources of electricity in the United States and currently accounts for over 12 percent of utility electricity production. The potential of the country's untapped hydro resources is quite large, and significant amounts of new hydroelectric power generation are anticipated for the future. As is the case for current capacity, new hydroelectric units will span the load range from peak through intermediate to base load.

Inventorying and assessing the potential for development of untapped hydroelectric power resources is the major focus and objective of the U.S. Army Corps of Engineers' National Hydropower Study (14, 15).* The potential for increased hydroelectric power production basically can be divided into three categories:

- Rehabilitation and/or expansion of capacity at existing hydroelectric power facilities
- Installation of turbines and generators at existing unpowered dams
- Development of new sites.

---

*Rather than trying to replicate this work here, the potential for new hydroelectric capacity will be briefly reviewed in Appendix B as to the alternatives to pumped hydroelectric storage. Appropriate data from the Corps study is incorporated in the analyses of pumped hydroelectric storage development potential presented in subsequent sections of this report.

The first two are sometimes grouped and referred to as the incremental potential, and the third as the undeveloped potential. Regional hydroelectric power production potential is detailed in Appendix B.

Environmental impacts produced by installing hydroelectric generating facilities are an important consideration of energy development planners. Most of the impacts associated with hydroelectric generation are highly site specific. Potential run-of-the-river impacts include "turbine-induced mortality and injuries to down-migrating fish, impingement at turbine intake trash racks, and siltation and release of toxicants in sediments from plant construction and from any required dredging of the old impoundment" (16). Development of a store-and-release hydroelectric capacity at an existing dam could produce water fluctuations possibly resulting in additional impacts.

Federal and state laws requiring the construction of fish ladders, elevators, etc., to facilitate the passage of anadromous fish at certain sites will have a cost effect on potential projects--especially at small-scale dams. Federal and state designations of river systems as wild and scenic can also reduce potential hydropower capacity development. As of December 1977, 4,845 miles of river systems in the United States were so designated by states (17). The effect of these laws is exemplified by the State of Oregon's designation of 524 miles of eight rivers, resulting in a loss of 2,371 MW of capacity that potentially could have been developed.

The capital investment required for potential new hydro capacity is highly site specific and depends on:

- The conditions of the dam (if one already exists)
- The size and type of the dam required if none exists, relative to the capacity of the unit
- The capacity of the unit (economies of scale)
- The hydraulic head.

In addition, streamflow characteristics in general, and the wide range of potential capacity factors in particular, combine with capital investment to yield an even larger range of potential power costs.

As to capital costs for small- and intermediate-scale developments at existing unpowered dams, Acres American, Inc., estimates the cost of new hydro currently to be in the general range of \$700 to \$1,500 per kilowatt (1976 dollars). Capital and other cost factors (see Appendix B), as well as environmental constraints and other considerations, will cause the realizable new hydro capacity to be substantially less than the physical resource. Nevertheless, there is a significant potential for new hydro capacity development over the next 20 years in all load ranges, including peak-load power generation.

3.2.3.7 Solar Photovoltaic Energy

Solar photovoltaic cells are discs of transistor-like materials that generate DC electricity at low voltage when exposed to sunlight. The output of such cells, which are grouped and wired into flat plate or concentrator collector panels, arrays, and modules, must be converted to AC and the available voltage stepped up before it can be transmitted and/or used for utility applications. Photovoltaic cells and arrays have been technically available for more than two decades; however, application has been limited to types of service that require little power and to applications in which cost is not a major consideration. Also, because of the intermittent nature of sunlight, photovoltaic cells will be best suited to fuel-saver or peak-load utility applications. Without dedicated or system storage, photovoltaic cells are not a firm "peaker" in the true sense, as is hydroelectric pumped storage. However, applications can include central station and dispersed systems, and a key characteristic of the technology is its intrinsic simplicity (e.g., no moving parts).

The principal barrier to large-scale use of photovoltaic cells, however, is their high cost--currently about \$10,000 per peak kilowatt for the cells only. The primary objective of Federal research and development efforts is to reduce costs to about one-twentieth of this figure by 1986. These efforts are centered in three areas: reducing the manufacturing costs of the single-crystal silicon cells that are now on the market; developing new production techniques for cells made from silicon and cadmium sulfide; and developing high-efficiency cells for use with concentrating collectors.

Photovoltaic systems produce no pollutants or major adverse impacts during normal operation. The principal environmental concerns involve worker exposure to toxic substances during manufacture. Also, if photovoltaic systems are considered in terms of displacing hydrocarbon technologies, the net environmental impact could well be positive.

Figure 3-3 shows the variation in average-incident total radiation on a horizontal surface across the United States. Roughly speaking, the solar radiation resource is greatest in the Southwest and least in the Pacific Northwest. However, several points should be noted with regard to the data in this figure:

- In practice, collector surfaces will be tilted or tracking, and thus will receive more radiation than shown here.
- Concentrator systems cannot use diffuse radiation but only direct radiation, which is significantly less than the total radiation shown.
- There is substantial hourly, daily, and monthly variation in insolation, and average December levels are only about one-half of average June levels.

Because of the reasonably close relation between the hour-to-hour output of a photovoltaic array on a clear day and electric utilities' typical daily peak-load demand profile in summer, photovoltaic systems have been classified here as a peak-load technology. In practice, though, they are not firm peak-load systems in the same sense as the other technologies in Category A, and a substantial portion of their value would be solely from the fuel use they displace (i.e., fuel-saver operation). Two of the principal reasons for this are that there is little or no output during cloudy periods, requiring backup elsewhere in the system; and since utility winter peaks generally occur in the early evening, photovoltaic cells without storage would be limited to displacing part of the intermediate load on a clear winter day, with little or no effect on the peak load (18).

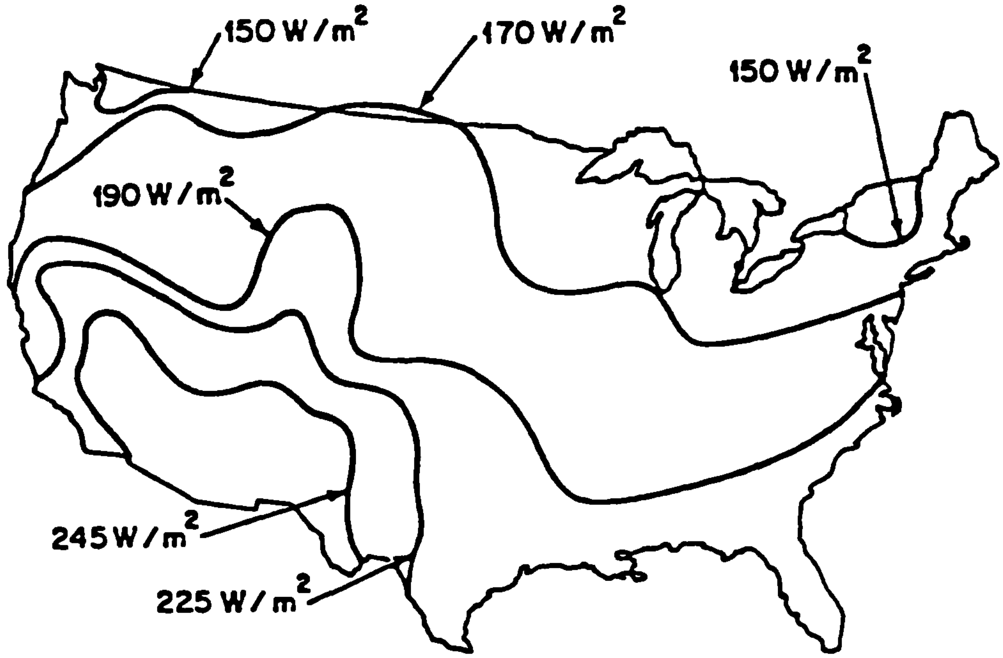
Also, current costs constitute a barrier to large-scale applications of photovoltaic systems. Though the price of a typical commercial solar cell array has been reduced by a factor of three or more over the past several years, photovoltaic cells with sufficiently low cost to make possible commercially feasible systems for converting large blocks of solar energy to electric energy have not yet emerged from accelerated research efforts. Basic research now must be followed by engineering development and demonstration of commercial feasibility.

3.2.4 Assessment of Category B Supply Alternatives

3.2.4.1 Oil Plant Conversion

At the end of 1977, almost 40 percent of the nation's large fossil powerplants were burning oil or natural gas as a primary fuel. Many existing oil-fired

Figure 3-3 Yearly Average of Solar Energy Incidence in Watts Per Square Meter (Horizontal Surface)



units--ranging in age from old to relatively new--were originally designed for coal use, though some were designed solely for oil firing. One aim of the Powerplant and Industrial Fuel Use Act of 1978 was to reduce by 1990 the amount of utility oil consumption to half of what it was in 1977, and to encourage greater use of coal, synthetic gas derived from coal, and other alternative fuels in utility boiler systems. To realize these goals, DOE has placed restrictions on existing coal capable facilities, and many have been ordered, individually or in categories, to convert back to coal. Methods for eliminating or reducing oil use include: conversion to coal firing; modification to burn oil/coal or oil/waste mixtures; and use of coal-derived and other synthetic fuels.

Anticipated conversions of existing capacity are incorporated in the analysis of development potential presented in Section 5.0. Of course, such conversions really do not provide new capacity and so could enhance the potential for pumped hydroelectric storage more than compete with it.

3.2.4.2 Combined-Cycle Plants

The combined cycle, as the name suggests, combines two different turbine systems for the conversion of heat into electricity in powerplants. In the first cycle, a clean fuel (distillate oil, natural gas, or gasified coal) is mixed with compressed air and burned; the hot combustion gas turns a turbine to generate electricity. When the combustion gas leaves the turbine it is fed through the boiler of a second cycle where it heats water into steam to power a conventional steam turbine to make more electricity.

Combined-cycle plants are attractive for a number of reasons. They use less water for cooling purposes than do conventional combustion turbine or steam turbine generating plants of a similar size, and they can provide significantly higher operating efficiencies (40 percent in current units and 45 percent in advanced designs). In addition, the technology is readily available; there are about 35 combined-cycle oil and gas units in the United States and somewhat more in the planning and construction stages (19). However, the capital cost of a combined-cycle powerplant, per kilowatt of capacity, is from 75 to 100 percent higher than for a simple-cycle combustion turbine plant (4). For example, EPRI estimates a complete capital cost of $340/kW in late-1978 dollars for a 250-MW combined-cycle plant, as compared to $190/kW for a 75-MW combustion turbine (9).

Plants of this type currently use distillate oil or natural gas and are generally used for cycling (intermediate-load) operation. The Powerplant and Industrial Fuel Use Act of 1978 imposes a limitation on new powerplants using oil and gas that operate no more than 1,500 hours per year (a 17-percent capacity factor). This will constrain future orders for combined-cycle units unless they can be operated with gasified coal or similar fuels.

3.2.4.3 Coal Gasification/Combined-Cycle

The concept of integrating a coal gasifier and a combined-cycle powerplant can provide some of the benefits of combined-cycle operation with the ability to use coal fuel cleanly. A coal gasification/combined-cycle (CGCC) plant would generate electricity from both gas and steam turbines (as described above), but would be powered by synthetic gas produced from coal. The gasifier would be constructed at the powerplant site and coupled to the power-generating equipment. Both Westinghouse and Texaco have designed coal gasifiers for use in CGCC plants (20, 21). Technological uncertainties stem mainly from a lack of experience with overall integrated system control (e.g., plant load-following capabilities) and gas-cleaning equipment design.

Considerable interest is being shown in CGCC technology, and the first commercial units may be operating within 10 years. However, while capable of intermediate-load operation, CGCC units are more likely to be used for base-load power generation, at least in their initial years of operation, because of their relatively high capital cost.

3.2.4.4 Fluidized Bed Combustion

In fluidized bed combustion, crushed and sized coal or other solid combustible materials are burned in a bed composed of inert materials, such as coal ash, sand, or alumina, and chemically active limestone or dolomite. During combustion, fuel is fed continuously into the boiler at the rate required to maintain the desired thermal output. The bed of solid particles is supported by a porous or perforated plate and held in suspension by a controlled stream of air passing upward through the plate with a velocity sufficient to cause the bed of particles to behave as turbulent fluid.

The advantages of fluidized bed combustion include:

- The flexibility to burn a wide range of fuels including high-sulfur coals without flue gas treatment
- Increased combustion efficiency and reduced combustion temperature with a higher heat transfer rate than conventional boilers
- Reduced boiler tube surface and furnace size
- Reduced NO_x emissions and greater than 90 percent SO_2 capture
- An easier-to-handle solid waste form more readily amenable to disposal than that from a wet scrubber.

The fluidized bed can be adopted to a variety of heat and power production modes in a number of ways; the two principal variants are atmospheric and pressurized operation.

The atmospheric fluidized bed combustion (AFBC) process operates with a combustion boiler at about atmospheric pressure and can be applied for process heat, space heat, or electricity generation (some demonstration projects are currently in operation). Pressurized fluidized bed combustion (PFBC) is similar to AFBC except that pressure within the combustor is maintained at between 3 and 10 atmospheres. Pressurized operation offers advantages over AFBC, such as higher combustion and sulfur capture efficiency, lower NO_x emissions, and reduced vessel size. PFBC advantages are most beneficial to utility applications, and PFBC could be used with a combined-cycle system of gas and steam turbines. However, the PFBC arrangement does require additional auxiliary equipment to maintain pressure during its operation. PFBC is still in the early stages of development, and its commercialization is generally estimated to be at least several years beyond that of AFBC (22, 23).

AFBC boiler technology faces some uncertainty for utility applications as long-term operational reliability has not yet been demonstrated. Other problems include the fact that it is still unknown whether or not moderate to high efficiency can be attained over a wide range of load conditions; starting reliability and rapidity must still be demonstrated; and further study of corrosion effects, load control, coal feed, and other aspects of large-scale units is required. AFBC plants are not expected to be commercial before about 1992 at the earliest (9, 23).

Estimates of the future potential costs of fluidized bed powerplants vary widely depending, among other things, on the degree of technical progress assumed. Overall, conceptual design studies generally estimate a mature capital cost between 80 and 93 percent of that for a conventional coal plant with scrubbers. The cost of early demonstration units will be significantly higher. Also, while intermediate-load operation is possible (and design improvements that would improve load-following capability are being investigated), fluidized bed powerplants are likely to be used mainly for base-load operation in the initial years of operation due to their relatively high capital cost.

3.2.4.5 Cogeneration

The term cogeneration applies to the production of both electricity and useful steam or heat from the same fuel. Cogeneration can save 10 to 30 percent of the fuel required to generate electricity and thermal energy in separate plants. In principle, cogeneration can be incorporated in most technologies that involve the use of heat to generate electricity, thereby providing a wide range of potential systems and fuels (24). Currently, cogeneration accounts for over one-third of industrial self-generation.

Many operating arrangements for cogeneration facilities are possible (25) but can be roughly summarized as follows:

- Electric utility-owned plants selling process steam or heat to adjacent or nearby industry
- Industry-owned plants generating process steam or heat for internal use, with excess electricity (if any) sold to the utility
- Jointly-owned facilities.

The potential for cogeneration is great and exists primarily within the larger energy-using industries, e.g., pulp and paper, chemical, steel, petroleum, food, and textiles (24, 26). However, the feasibility of developing this potential is limited by a large number of factors, including:

- Siting restrictions and regulatory requirements
- The size of the facility and the type of fuel it will use
- The cost of electricity that the plant displaces and the price paid for sales of excess power to the utility

- The cost of standby power and whether or not a capacity value will be included in the price paid for electricity sold
- The extent of plant utilization (capacity factor)
- Whether overall the facility will yield a sufficiently attractive return on investment (usually around 20 percent per year).

In general, economic attractiveness improves with increasing plant size, higher energy rates, increasing the capacity factor, and less expensive fuels (e.g., coal or residual oil).

Cogeneration has significant potential to improve the efficiency of energy production. Its impact on utilities will be seen primarily as some reduction in demand and a supplemental source of power, principally in major industrial areas. Due to economic factors and the needs of industrial users, cogeneration will be operated mostly as base-load, and to some extent as intermediate-load, energy production. Purchased from nonutility generators at the utilities' incremental costs of generation, it will have little or no effect on other consumers' electricity costs.

3.2.4.6 Solar Thermal Power

A solar thermal electric powerplant is similar to a conventional powerplant but with the fundamental difference that the steam driving the turbine is generated by heat focused by the sun's rays rather than by burning fuel. The two basic concepts are the distributed collector system (e.g., parabolic troughs) and the central receiver system (power tower). Both concepts require a backup source of energy to ensure reliability for utility applications because of both diurnal and intermittent cloud conditions.

For utility applications, development efforts are currently concentrated on the central receiver system because of the potential for higher efficiency and lower costs. Because of the much higher levels of direct solar radiation there, deployment of solar thermal energy plants will be limited at least initially to the Southwest; there is a test facility currently in operation at Albuquerque, New Mexico. Areas of existing utility concern regarding solar thermal electric systems include:

- Cooling water requirements and other siting restrictions (e.g., because of its steam-cycle operation and the land needed for the mirror arrays)

- System and plant reliability (e.g., effects of intermittent sunlight, momentary outages, dispatching problems)
- Materials performance and lifetimes (e.g., effects of large and rapid thermal fluctuations on the receiver boiler)
- Overall system economics and cost uncertainties (27).

A recent DOE status report (28) stated: "Neither central receiver nor dispersed collector systems are commercially available today. If either system were to be built with currently available components the cost would be $7,000 to $10,000 per kW-pK." Pilot solar thermal powerplants currently planned for the Southwest will be designed for intermediate-load operation with conventional backup, but they will not be economically competitive. Other regions of the country having lower direct insolation would require larger concentrating mirror areas and storage capacities that would result in higher costs, and significant cost reductions would be necessary to make solar thermal energy economically competitive with other sources. In particular, the cost of heliostat (tracking mirror) systems would have to be reduced to around 20 to 30 percent of current costs (29).

3.2.4.7 Wind Energy

Windmills have been used to generate electricity since 1890, and many different types have been operated since that time. The principal goal of current U.S. wind turbine programs is to lower costs through the development of new materials and production methods and through research into new designs. Most wind machines today are of the two- or three-bladed horizontal axis type, though development and demonstration of vertical-axis (Darrieus) machines are also under way.

Overall, large wind turbine operating experience to date is quite limited, and wind turbines are essentially in the demonstration stage. It will be several years before they are in multi-megawatt-scale mass production, in part because blade stresses and fatigue are still an important consideration. Several machines have lost blades, and the DOE/NASA machines at Sandusky, Clayton, and Culebra Island encountered blade stress problems in the early months of their operation. Additional development and testing also is needed in order to better understand wind machine interface with electrical grids, and maintenance requirements are still uncertain. Further work on siting methodology is required--particularly the development of better means of estimating the meteorological characteristics of potential sites (27).

Like photovoltaic cells, wind turbines are an intermittent source of energy, and current plans call for operating them without dedicated storage. Thus, their primary value in utility systems is as "fuel-savers," i.e., their capability to reduce fuel consumption elsewhere in the grid when the wind is blowing above the cut-in wind speed. Also, while wind turbines do have some ability to displace the need for conventional generating capacity, it is important to note that this is on much less than a one-for-one basis.

As yet, methods for predicting wind characteristics at potential turbine locations do not provide the levels of confidence desirable for siting, though substantial improvements are being made. In general, the best sites for wind turbines are likely to be: mountain ridges or exposed knobs; gorges that funnel prevailing winds; open flatlands; and exposed coastal locations. The physical capability of potential multi-unit site areas will be constrained to some extent by the need to space turbines at least 10 to 15 diameters apart to prevent the "shadowing" of one turbine by another. This will limit average output to roughly 3 MW per square mile (10).

Average wind speeds also vary with the time of year; they are generally higher in winter than in summer, and average winter output may be twice as high or more than the summer average output. Also, wind speeds often exhibit significant variation during the day, and in some areas mean wind speeds are highest around the middle of the day (30, 31). In rough terms, this potentially could provide some assistance in load-following, on average.

Estimates and reported capital costs for large wind turbines vary widely, ranging from around $500 per rated kilowatt to as high as $10,000/kW for the 200-kW DOE/NASA machine on Block Island. However, comparing capital costs in dollars per kilowatt must be done carefully since the rated wind speeds of machines typically vary from 20 to 40 mph. Additionally, cost estimates do not always include the cost of installation. Projected installation costs for mass production are typically about $100 to $200/kW. However, DOE/NASA has estimated an installation cost of about $1,000/kW for its 200-kW MOD OA machine at a readily accessible site (32). Capital costs are expected to be lower in the future, based on bringing current designs into mass production.

Estimates of future installed wind capacity vary greatly, with projections for the year 2000 ranging from nominal amounts to around 45,000 MW (33). Recent Congressional legislation has focused on a goal of about 800 MW of installed wind capacity by the end of this decade. The actual outcome will of course depend in great measure on the extent to which costs can be reduced.

3.2.4.8 Tidal Power

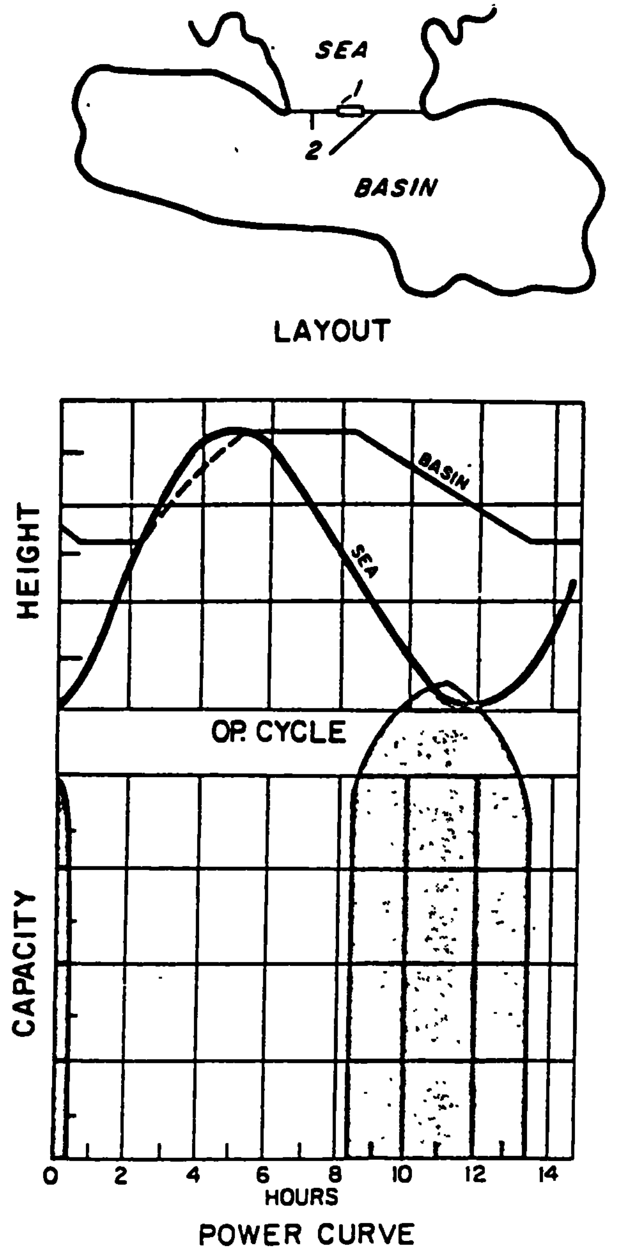
Tidal power schemes require the damming of bays or estuaries to form operating basins or pools. A minimum difference in head of about 5 feet between the basin and the sea, or between paired basins, is usually needed to permit power generation. With the variation in tides (neaps and springs) about the average range, and the need for more than sporadic power generation, a viable tidal power project requires a site location where the mean tidal range is at least 15 or 16 feet. Operation is similar to low-head hydro projects, except that power generation depends on the tidal cycles and is therefore not continuous.

There are many schemes for producing power from the tides. Current design analysis is showing a preference for simpler single-pool and two-pool schemes. Single-pool schemes may involve electricity generation on either the flood tide, the ebb tide, or both. Unidirectional generation is referred to as "single effect" operation and bidirectional flow as "double effect" (see Figure 3-4).

Reverse-directional pumping may be a desired supplement for both single and two-pool designs to increase the operating head and power output, particularly under neap tide conditions. With some versions of the two-pool scheme it is possible to produce some power at all times, although the amount of power generated varies greatly with the tides. This provides a certain amount of dependable energy. Due to tidal variations, a feasible tidal power scheme cannot maintain a constant power level. Furthermore, the variation in tidal range from spring tides to neap tides and the 50-minute-per-day advance in tides limits the extent to which electricity load demands can be met. Depending on the scheme that is used, a tidal plant might range from fuel-saver to intermediate-load operation.

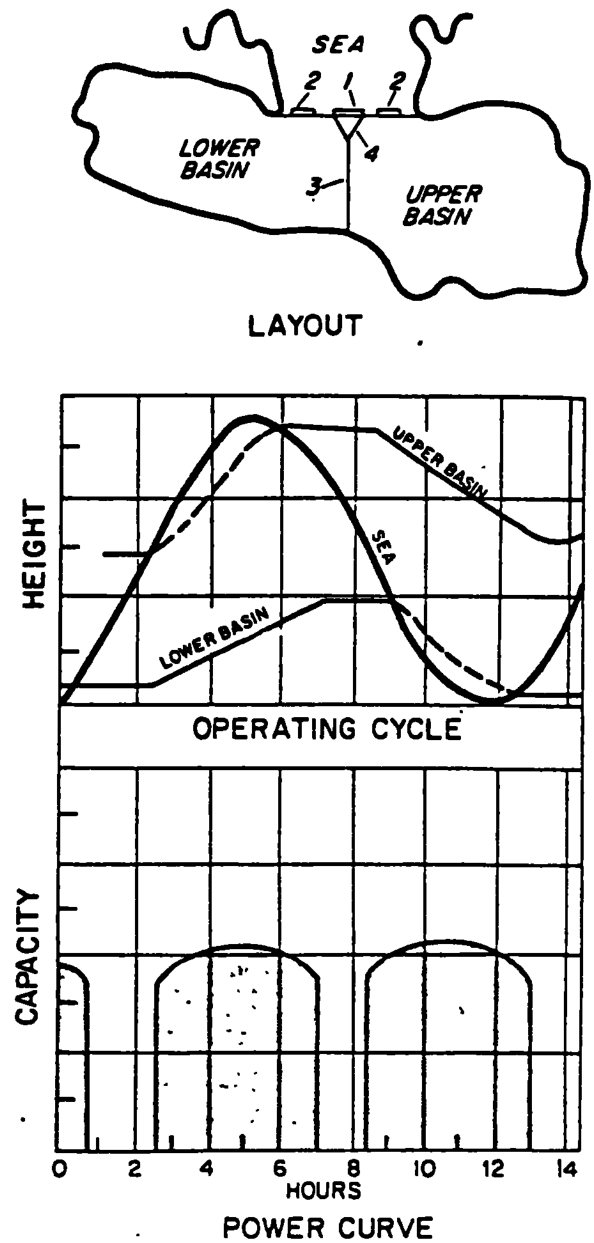
The only large tidal plant constructed to date is the 240-MW Rance Station located in the Rance estuary upstream of St. Malo, France. The only potentially developable tidal power sites in the United States are the Passamaquoddy Bay

Figure 3-4 Single-and Double-Pool Tidal Schemes



LEGEND
1 – POWERHOUSE; 2.– MAIN DAM, NO SLUICES, DISCHARGE THROUGH POWERHOUSE. (GENERATION BASIN TO SEA)

SINGLE-BASIN SINGLE-TIDE WORKING INSTALLATION



LEGEND
1 – POWERHOUSE; 2 – MAIN DAM WITH SLUICES
3 – SEPARATING DAM; 4 – DAM FOR BASIN SWITCHOVER.
(GENERATION ALTERNATES SEA TO LOWER BASIN AND UPPER BASIN TO SEA)

DOUBLE-BASIN SINGLE-TIDE WORKING INSTALLATION

Source: Reference (58).

Region (including Cobscook Bay) in Maine and the Cook Inlet Region (near Anchorage) in Alaska.

Tidal power development is not without environmental impacts, both adverse and beneficial. Among the physical impacts expected to occur would be: the physical obstruction created by the dams and the local disruptions from their construction, altered water levels and tidal ranges in the basins, reduced tidal exchange or flushing, change in current patterns, less vertical mixing, lower rates of oxygen uptake, greater stratification, higher summer temperatures in the basins, reduced salinity in the surface layers, enhanced winter icing in the enclosed basins in colder regions, reduced dissolved oxygen in deeper layers, and altered erosion and siltation patterns. These effects would occur primarily within the enclosed basins or within their immediate vicinity. Specific site investigations would be required to adequately determine the environmental impacts of a particular scheme (34).

There are no firm plans at present to build any of the cited tidal projects. It is not likely that construction of any of these projects would begin until the mid- to late-1980's, at the earliest. Estimated construction times range from 4 to 10 years, depending on the individual project.

3.2.4.9 Wood and Other Biomass

Biomass production and conversion are concerned essentially with the generation of energy from terrestrial and marine plant life. Within these plants, energy from the sun transforms elements from the air, water, and soil into organic compounds, primarily carbohydrates. The major source of energy in plants is cellulose, a common carbohydrate that is a primary product of photosynthesis. The principal drawback to biomass production is its low efficiency; efficiencies for conversion of solar energy to biomass by photosynthesis are generally on the order of 0.4 to 1.3 percent (1 to 3 percent of "photosynthetically active radiation") (35). This does not include the efficiency of converting biomass to useful energy.

The principal source of biomass energy being considered for utility application is wood. Other potential sources of biomass for energy include farm wastes from crop harvesting (cornstalks, vines, leaves, stubble, etc.). Much of this material is now burned on the farm or is left on the land as fertilizer and to prevent erosion. Other sources include mill residues such as corn cobs and bagasse from sugar mills and grains. In some parts of the country the collection and subsequent conversion to energy of these residues may be feasible--for example, in the Corn Belt. It is also possible that biomass energy could be produced from ocean plants (34), although it is unlikely that this will be a significant energy source in the near future. Energy crops may be used for direct combustion, pyrolytic production of fuel oils and low-Btu gas, or for fuel production by anaerobic digestion.

The potential availability of biomass resources for energy production by region of the country is given in Table 3-3 (see also Figure 3-5). The total potential estimated by the MITRE Corporation is about 11.4 quads per year (36). About 40 percent of this would come from agricultural and silvicultural biomass plantations. It is not expected that a significant amount of energy will be produced from biomass farms within the study time-frame.

3.2.5 Assessment of Category C Supply Alternatives

As mentioned above, about half of the candidate supply technologies were screened into Category C because they are unlikely to be commercially available before the year 2000 and/or because they will be used for base-load power generation. These technologies are summarized in Table 3-4 and briefly discussed in Appendix B.

Table 3-3 Estimated Potential Availability of Biomass Fuels

	Potential U.S. Availability (Quads/yr)	Availability by Census Region (Percent of total)								
		NE	MATL	SATL	ENC	ESC	WNC	WSC	MT	PAC
Logging Residues	1.7	3	3	20	7	22	3	17	4	21
Standing Biomass	1.3	11	15	35	16	18	12	7	8	-22
Mill Residues	0.5	6	5	19	6	10	2	8	11	33
Biomass Farms Silviculture Agriculture	4.5	3	5	26	12	14	10	27	0	3
Crop Residues	3.4	0	2	5	17	3	44	10	10	9

Source: Reference (36).

Figure 3-5 Estimated Potential of Selected Biomass Fuels in Megawatts by U.S. Census Regions (Not including Biomass Farms)

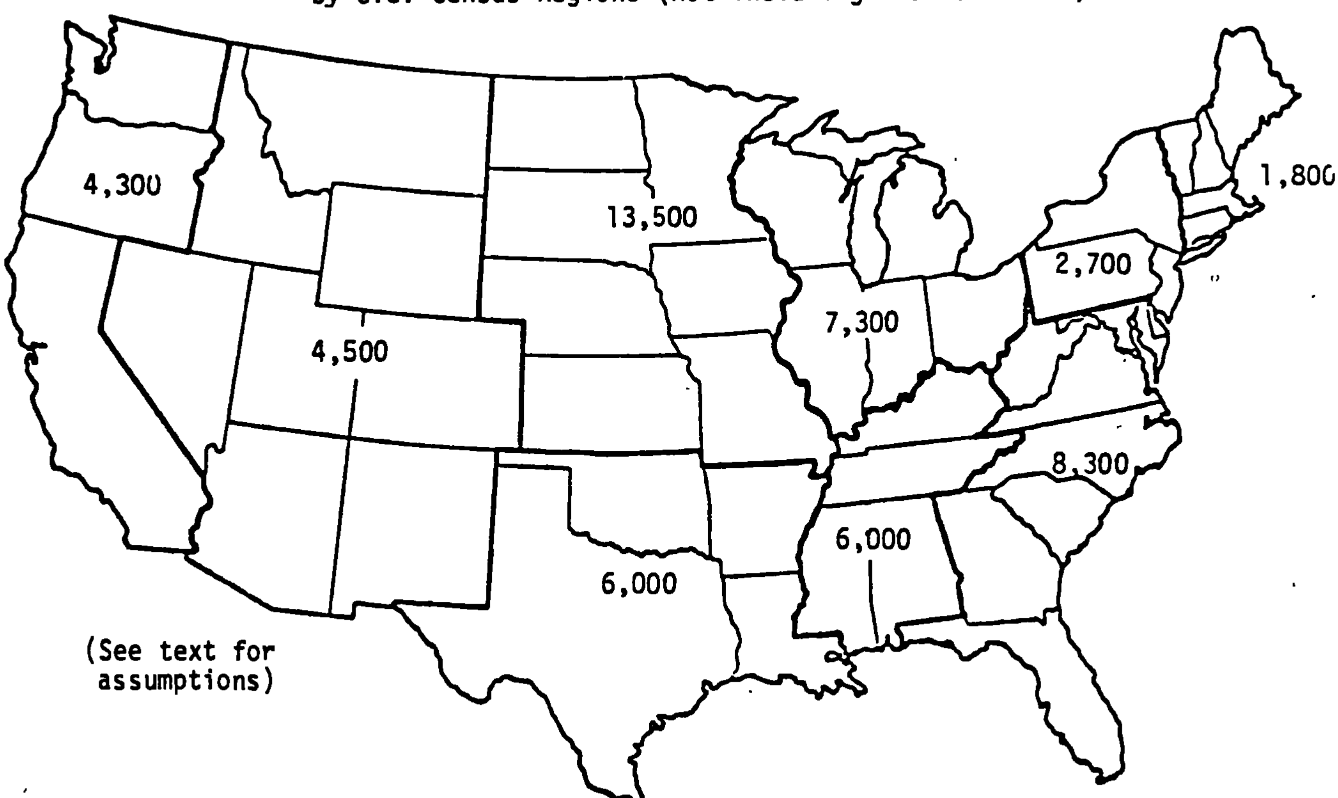


TABLE 3-4

Summary Characterization of Category C Alternative Supply Technologies

Technology	Availability*	Comments
Geothermal	Current	Primarily base-load; prime resource areas: West Coast and Gulf Coast.
Solid Wastes	Current	Primarily base-load; supplemental resource.
Nuclear Converters and Breeders	Current	Baseload. European programs further advanced than U.S. programs.
Solvent Refined Coal	1990	Base-load
Molten Carbonate Fuel Cells with Coal Gasifier	Mid-1990's	Base-load
Ocean Thermal	Early 1990's	Base-load; prime resource areas: Hawaii, Puerto Rico, and Gulf of Mexico.
Fusion Magnetohydrodynamics Bottoming Cycles Thermionic Conversion Solar Satellite Wave Currents Capacitors Flywheels Superconducting Magnets Hydrogen Thermochemical Pipelines	Commercial deployment by utilities before 2000 not anticipated.	

*Date of earliest commercial operation; includes lead time from first commercial orders.

3.3 DEMAND ALTERNATIVES

3.3.1 Thermal Storage (Demand-side Technologies)

Thermal storage is used by electricity customers to reduce the cost of service. Its overall effect on an electric utility is to reduce capacity requirements and usually to increase energy requirements, an effect that arises from energy lost from the storage.

The most common demand-side thermal storage technology is the domestic hot water tank. This system allows water to be heated over an extended period for use in short periods. It thereby reduces the heating power (but not energy) required. Without storage, domestic hot water would be limited to instantaneous service, such as the hot water faucets often seen on drinking fountains or in lunchrooms. This is a case where thermal storage makes a modern technology feasible.

Another demand-side thermal technology that is common in Europe (though not in the United States) is thermal storage systems for space heating. During off-peak hours, ceramic bricks are heated by electricity. The building is then heated by circulating air over the bricks during the on-peak hours. In some parts of Germany, for example, electric storage heaters represent nearly 25 percent of the total demand for electricity, and in winter the daily load curve for the utility is nearly flat (37). However, further installations are not being encouraged, lest a new peak be created where none existed before.

Nearly all solar space or water heating schemes involve storing heat, often in water. Demand-side storage of low temperature thermal energy from solar sources has the advantage over supply-side storage of reducing the difficulty and cost of transporting low temperature heat by water. Demand-side storage becomes the needed backup to provide heat when there is no sunshine. The net effect of solar heating will be to reduce electric energy requirements. However, unless very large storages are provided, there will be periods during extended sunless weather when electric heating will be required.

In general, the storage of heat by residential or commercial customers in either water or a solid is technically simple and is limited only by economic considerations. Storage of coldness is more complex. The effective capacity of chilled water cooling systems used for commercial buildings can be economically increased by the use of chilled water storage. The storage allows the reduction of operating costs by taking advantage of lower time-of-day (TOD) rates, by limiting maximum demand charges, or by operating at night to fill the chilled water storage when outside temperatures are lower. Prototypes of systems to store cooled water or ice are being tested; they are bulkier and costlier than heat storage. It has been estimated that cool storage could reduce air conditioning peak electric demand by up to 50 percent in some parts of the United States (90) since coldness can be stored on an annual cycle using a heat exchanger and the winter air; however, a large storage volume would be needed.

For larger installations, storage in aquifers has been suggested, and one such system has been proposed for JFK Airport. In this case there are two wells, one at 34°F and one at 40°F. In summer water would be pumped from the 34° well, through a heat exchanger (where the ventilation air would be cooled), and into the 40° well. In winter water from the 40° well would be pumped back to the 34° well via a cooling tower, which produces the temperature drop.

In Great Britain a program of encouraging heat storage in residences has been in effect for 20 years (38). In 1979 about one out of eight British homes had off-peak central heating. There are two rates; the off-peak rate applies for 7 hours a night and is about 30 percent below the on-peak rate. Commercially available items include storage radiators, storage fan heaters, central heating systems with heat storage, and floor warming systems. (A storage radiator is a heat storage unit without a fan, using only convection to transfer its heat; it is suitable in size for heating only one room.) A typical central heating system has a capacity of 7 kW and storage of 46 kWh, and larger sizes (to 15 kW) are available. A time-based meter on the customer's premises records on-peak and off-peak usage separately, and turns on the off-peak power to storage heaters and hot water heaters. Weather-sensitive controllers are available to control the quantity of heat stored. Line voltage signalling with ripple control is also used.

The Saskatchewan Power Corporation is studying off-peak heating by an electric furnace with thermal storage (39). Five furnaces of 23-kW heating capacity and 140-kW storage capacity have been built and are being tested. The cost was $3,625 per furnace, but these were hand-made units, and it is expected that the cost would be considerably less for a production model.

The American Electric Power (AEP) system has tested 70 residential electric thermal storage (ETS) space- and water-heating equipment installations in its service areas. A 14.4 kW (105 kWh) heat-storage furnace of English design was modified by adding a 10-kW, conventional electric-resistance heating furnace. A special electric thermal storage hot water heater with a 120-gallon capacity and three elements giving 4.5 kW, 3 kW, 2 kW, or 1 kW was also tested. Its special features included improved tank insulation, diffused inlet water supply, and a load-leveling heating control that spreads the heating requirements out over an 8-hour heating period. It was reported that 91 percent of customers in the test found the ETS space heating satisfactory, and an equal percentage of customers found their hot water supply acceptable. The AEP is said to believe that about 100,000 such units could be added to its system without any problems, and the utility has filed for off-peak rates to accommodate ETS furnaces (40).

At least 56 U.S. electric utility systems are sponsoring or conducting thermal energy storage projects (41). These include:

Annual-cycle energy storage	2
Central ceramic heat storage	22
Comparative studies of thermal storage	3
Concrete walls cool storage	1
Eutectic salts cool storage	1
Combination heat and cool storage	11
In-ground heat storage	3
Ice cool storage	21
Pressurized water heat storage	9
Room ceramic heat storage	6
Water heat storage	2

Many experiments are still underway, but preliminary conclusions indicate that thermal energy storage systems are effective in improving load profiles, provide dependable, automatic operations, and are economically feasible if incentive electric rates are adopted. A complete list of utilities and their projects can be found in Smith (41).

3.3.2 Load Management

"Load management," as described by the Electric Power Research Institute (EPRI), "deals with customer loads--by category or in total--as they exist today and as seen from the utility's side of the electric meter. Load management covers a user's own efforts to shift or reduce his pattern of electricity use when those efforts are stimulated by utility rate incentives." A joint EPRI and Department of Energy (DOE) project states:

> The objective of Load Management is to alter the real or apparent pattern of electricity use in order to:
>
> - Improve the efficiency as well as the utilization of generation, transmission, and distribution systems;
> - Shift fuel dependency from limited to abundant energy sources;
> - Lower the reserve requirements of generation and transmission capacity;
> - Improve the reliability of service to essential loads.
>
> Load management is particularly attractive in terms of its potential for conserving energy and capital in production and distribution of electric power; for shifting a significant amount of the fuel base from oil and gas to coal, nuclear, and renewable resources; and holding down the cost of electricity (42).

The peak-shaving achieved by load management enables the electric utility to increase its load factor (ratio of average load to peak load) and thus deliver more energy using the same generating capacity. This delays the need to construct additional generating plants, and reduces the need for forming additional capital.

Load management is mainly concerned with the control of peak loads, which furnish only a small fraction of total energy. Consequently, even though peak loads are replaced by loads served at lower cost, the savings in generating costs apply only to a small fraction of system output. Studies by EEI project generating cost savings of only about 1 percent.

There are two general approaches to load management. In the first the utility provides the customer with an economic incentive to manage his own load. Demand-based rates (peak load pricing) and time-of-day, seasonal, and interruptible rates are the techniques of this approach. In the second method, the utility manages the customer's load and usually charges a lesser price for the electricity. Utility control of water heaters, air conditioners, or space heaters typifies this approach.

3.3.2.1 Rates

Unlike many worldwide electric utility systems, demand charges are common in the United States only among large commercial and industrial users, where energy use is large and the cost of metering and special billing is low. Demand controllers that are programmed to keep the customer's total demand below a certain level are widely used. These increase the user's load factor and the system load factor, and there is no doubt of their effectiveness.

The Public Utility Regulatory Policies Act (PURPA) of 1978 (43) makes time-of-day, seasonal, and interruptible rates standard for practically all utilities in the United States. Rates must also take the cost of service and load management measures into account. The intent of the act is to encourage the conservation of energy, the efficient use of facilities and resources, and equity of rates among different customers of electric utilities. At the request of the National Association of Regulatory Utility Commissioners, a very extensive Electric Utility Rate Design Study (EURDS) was conducted by the Electric Power Research Institute (EPRI), the Edison Electric Institute (EEI), the American Public Power Association (APPA), and the National Rural Electric Cooperatives Association (NRECA). The EURDS report composes about 100 volumes and analyzes the effects of the various rates prescribed by PURPA (insofar as the state of the art permits). A difficulty common to all these studies is the shortage of information on the effect of these rates in the market sector. In respect to load management some researchers conclude that "The major limitation of these studies is that none of the methods is capable of (1) taking as an input a particular load management strategy and (2) providing as an output either the cost-benefit ratio associated with such an action or a rate structure that could accomplish the desired load shape or load pattern change" (44). The EURDS, however, does suggest methods by which such results might be obtained.

A survey of electricity demand and consumption by time-of-use (TOU) was sponsored by EPRI for the National Association of Regulatory Utility Commissioners. In presenting the report, the EPRI project manager writes:

> The findings of this survey show that we barely scratched the surface in obtaining hard data on customer behavior under time-of-use pricing. Within both the utility industry and the government there is great interest in knowing the elasticity of demand with respect to peak load pricing. (Results of this survey) caution against the ready acceptance of any estimate of the time-of-day elasticity at this time (45).

There have been, over about 4 years, 14 projects on residential TOU rate experiments sponsored by DOE. The EPRI authors critiqued each of these, and found that eight were flawed. However, regarding the others, two completed experiments and four others in progress offered the prospect that their data could be used to estimate TOU price effects. After a review of the various analyses that have been performed on these experiments, the EPRI authors significantly concluded:

> By way of conclusion, at this point we can say very little about the quantitative effects of TOU or seasonal pricing on residential customers even on a local level. What results there are show tendencies, but are insufficient for making policy decisions. . .to date, all the available experimental evidence on TOU pricing lies with residential customers (45).

The EPRI study results from each of four utilities with mandatory TOU rates for commercial/industrial customers are described below.

Wisconsin Power and Light has had such a rate since January 1977 for about 130 large customers. "On-peak kW's cost between $4.50 and $5.00 each and the ratio of on- to off-peak kWh charges is 2:1. Preliminary estimates are that 8 to 10 percent of the entire class load has been shifted out of the peak period and about 6 percent of the kWh's consumed."

San Diego Gas and Electric Company, Pacific Gas and Electric Company (PG&E), and Southern California Edison Company have rates with much smaller on/off-peak kWh differentials, and the utilities report shifts of 1.5 percent or less except in the cement industry; here the shift in demand was 1 to 4 percent in the summer and 3 to 6 percent in the winter. It was noted by Pacific Gas and Electric Company that the ability to shift depends largely on whether the plant is operating at or below capacity. The EPRI authors point out that "It is really too early in the history of such rate structures to expect much response, especially since many industries would have to undergo extensive alterations in their production technologies to do so."

At PG&E there is only a 15-percent difference in the energy charge between on-peak and off-peak hours, but there is a large difference in peak-demand charges (46). Consequently, the incentive to shift load out of the peak period is mostly in this area. Almost all the firms showing a definite response to TOU rates are in the cement, primary metals, paper products, or industrial chemicals industries, although many firms in these industries do not seem to have changed their usage patterns as a result of TOU rates. (For the entire rate-class, load reduction as a result of TOU rates is estimated as 1.3 percent in winter peak hours and 2.0

percent in summer peak hours.) However, the authors point out that a lack of knowledge of the effects of TOU pricing reflects both the unavailability of data and methodological problems in data collection and analysis.

In Europe large nonmanufacturing industrial energy users--such as the chemical, refining, and steel industries--have been very responsive to such pricing. This study of TOU pricing in Europe incidentally concluded that such pricing would ultimately reduce peak industrial electric demand in United States significantly.

3.3.2.2 Load Controls

Load controls are the means by which a utility manages some portion of the customer's load. The utility commonly uses a communications and load control system (C&LC) to control a water heater, air conditioner, or space heater. Often the utility makes a reduced charge for electricity delivered under load control.

Load control programs are just coming into common use in the United States; a list of large-scale utility load control programs is given in Table 3-5. Costs of the C&LC system per metering point are given on Table 3-6. As can be seen in the table, under load management programs, the cost per kilowatt of capacity is lower than that for peaking plant generation costs, which are presented in Tables 4-1 to 4-15 (pp. 4-8 through 4-22).

The load management program at Minnkota is perhaps unique in that it is directed toward improving the annual load factor rather than the daily load factor. The dual heating system used by Minnkota is a dual electric/oil furnace. Oil (or natural gas) is used to meet extreme peak loads--perhaps 10 percent of the total annual energy (47).

In contrast to the effects of pricing, the effects of load management can be predicted, analyzed, and calculated. Hudson (48) has studied the effect of the load management of residential storage heating, storage air conditioning, or water heating. The tool used was a power system generation expansion planning code, and the utility modeled was System A of EPRI's synthetic utility systems. It was assumed that 1 or 5 percent of the annual system peak load was deferred by controls. The cases and some results are tabulated as follows:

TABLE 3-5

Large-Scale Utility Load Management Programs

Utility	Type of C&LC System	Number of Receivers	Principal* Load(s) Controlled
Arkansas Power & Light	Radio	NA	AC
Buckeye Power	Radio	42K	WH
Cobb Electric Membership Coop.	Radio	13K	AC
Detroit Edison	Radio	200K	WH
Lumbee River Electric Membership Coop.	Radio	8K	WH
Minnkota Power	Ripple	4K	DHS
Shenandoah Valley Electric Membership	Radio	2.5K	WH
Southern California Edison	Hybrid	14K	AC-WH
Walton Electric Membership Coop.	Radio	8K	AC-WH
Wisconsin Electric Power	Powerline Carrier	150K	WH

*AC - Central air conditioner.
WH - Water heater.
DHS - Dual heating system.

SOURCE: M. D. Nelson: "Minnkota's Load Management Program: Economic Aspects," Power Apparatus and Systems, Vol. PAS-99 No. 5 (Sept/Oct 1980).

TABLE 3-6

Load Management Programs--Cost Summary

Utility	C&LC System Per Point Cost ($)	Per Point Benefit (kW Load Relief)	Cost $/kW
Buckeye Power	105.00	1.1	95.45
Cobb EMC	92.80	1.3	71.38
Detroit Edison	89.50	1.0	89.50
Minnkota Power	663.00	10.00	66.30

Source: Nelson, 1980 (Reference 99).

Scenario	Annual Load Factor (%)	Costs* (millions of dollars)
Base-case scenario peaking utility	63.7	17,987
1-percent deferral by conventional water heater	64.3	17,780
5-percent deferral by conventional water heater	67.0	17,714
1-percent deferral by storage water heater	64.3	17,775
5-percent deferral by storage water heater	67.0	17,544
1-percent deferral by storage air conditioner	64.3	17,780
5-percent deferral by storage air conditioner	67.0	17,625
Base-case winter peaking utility	64.4	18,402
1-percent deferral by storage space heater	65.1	18,293
5-percent deferral by storage space heater	67.8	18,220

Results show that, as expected, load management makes it possible to defer system capacity expansion while still meeting system reliability requirements. Load management flattens the daily load curve so that the reduced system peak can be met using less capacity. When base-load plant additions are deferred, operating costs are increased because intermediate and peaking plants with higher operating costs must be used to a greater extent. However, this cost increase is more than offset by savings from the deferral (or cancellation) of new generating plants.

Another aspect of load control has been studied by Kuliasha (49), who used a gradient dynamic programming model to analyze the operation of a power system incorporating load control. Both the generation system and the load are controlled to optimize costs. A number of synthetic electric utility systems were simulated using a variety of load control options. Results indicate that the cost savings achieved through direct load control are highly dependent on utility characteristics, load characteristics, pumped storage capacity, and penetration.

Production cost savings for the simulated cases analyzed were as follows:

*Total present worth of system costs (present $), capital + fuel + O&M.

Connected Load	Device	Hours Deferrable	Production Cost Savings (10^3\$)		
			System A	System D	System F
500 MW	Water Heater	6 hr	32.0	193.3	59.1
100 MW	Water Heater	12 hr	35.8	310.7	
500 MW	Storage Air Conditioner	12 hr	73.2	781.0	
1,000 MW			133.9	1,276.3	
500 MW	Storage Space Heating	16 hr			74.2

The greatest variability in system marginal costs offers the greatest savings. The load characteristics producing the greatest savings are large storage capacity, high coincidence with system peak, large connected load per control point, and moderately high diversity fraction.

An important result involves the interaction between load control and pumped storage. This is a consistent trend toward decreased utilization of pumped storage as the amount of controlled load increases. Load control and pumped storage compete for the same swing in system marginal costs. But pumped storage has a round-trip efficiency of only 65 to 75 percent and is limited by reservoir capacity, whereas load control has almost 100 percent efficiency but with variable capacity and numerous operational constraints. In the case studies detailed above the load control system was chosen as the preferred resource because of its higher energy efficiency.

3.3.2.3 Impact of Load Management

DOE has sponsored a recent study (50) of the impact of load management on the future of intermediate and peak generating technologies (IPT's), specifically considering pumped storage. Load management actions that were simulated include:

- Space heating and cooling incorporating energy storage
- Hot water heater control
- Changes in hourly electricity consumption patterns
- Changes in total electric energy consumption
- Interruptible service.

An electricity-cost-minimization model was used to examine the role of IPT's in the year 2000 with and without load management. Insights from the study include:

- A large fraction of annual demand variation is due to seasonal and weekly demand cycles.
- Most load management will reduce only daily demand fluctuations.
- Future load shapes are very sensitive to electric space heat saturations in both the new and retrofit markets.
- Energy use data for the commercial sector is weak.

The DOE study concluded:

- There will be a need for IPT's in the year 2000, and the probability is high that the demand for IPT's will be about the same as it is today. The required capacity (with less tha a 15 percent capacity factor) is in the 10 to 30 percent* range under a broad range of growth and load management scenarios.
- The need for IPT's will be greater in the South Central region because of continued strong summer peaking.
- Annual load factor increases of more than 10 percentage points are unlikely even with a high level of load management success.
- The greatest load-altering potential exists in the following end uses:
  - Industrial load management
  - Cool storage in summer peaking regions
  - Space heat storage in winter peaking regions.

  This conclusion is based on estimates of the amount of demand that can be reallocated among time periods and the beneficial effect of the reallocation.
- As in the past, growth in space conditioning loads will be the single most important determinant of spontaneous changes in electricity demand patterns.

*Percent of installed capacity.

- Without load management, storage could account for 20 to 30 percent of installed generating capacity in the year 2000 (assuming a 75 percent turnaround efficiency). Load management will probably reduce this potential by fewer than 10 percentage points (50).

3.3.3 Conservation

There is virtually no field of applied science or technology today in which conservation is not actively pursued and promoted. Some conservation is voluntarily motivated by patriotism or thrift and a hatred of waste, but more commonly, conservation occurs for economic reasons; as costs rise, users find that they prefer to use less electricity and divert funds elsewhere. Also, for economical reasons there can be conservation as an investment; a new energy-efficient applicance may be bought to replace a less efficient one when cost estimates show that the lifetime cost of buying and operating the new applicance is less than the lifetime cost of operating the old one.

There are guidelines for residential, commercial, and industrial users in every specialty. For large buildings a number of computerized systems for economical control of heating, cooling, and lighting are available; computer buffs have their own systems in residences. Energy-efficient designs for new buildings of all types and sizes have been developed. Under economic pressure, interest in improving the efficiency and power factors of small motors has been rekindled, and utilities are taking renewed interest in measures to reduce transmission and distribution losses. New energy-saving processes are being adopted in industry after industry, and old plants are being converted to new methods or replaced. In a representative case a specifically equipped new building is estimated to use 40 percent less energy than a comparable building without energy-saving features, while the special features added only 2 percent to its cost. The extra cost is expected to pay for itself within 2-1/2 years (51).

End-use conservation does not necessarily mean minimizing the total use of electric or any other form of energy. It is aimed at eliminating "wasteful" or unjustified consumption, involving a commitment of scarce resources that end-users value more highly than consumption. When end-users are faced with prices that reflect the actual costs of the resources used in producing electricity, electricity is consumed only to the extent that the value of additional electricity consumption to consumers is equal to or exceeds the cost to society of producing the additional energy.

One of the major purposes of the Public Utilities Regulatory Policies Act (PURPA) of 1978 is to encourage conservation of energy supplied by electric utilities (43). PURPA establishes a set of ratemaking standards whereby the cost of electricity will reflect the cost of providing such service. Such rate designs would encourage the societally appropriate degree of consumption and, by implication, conservation. The guidelines for implementing PURPA call for electric utility rates to be based on marginal costs, which PURPA requires each utility to calculate. The guidelines argue, "Marginal cost-based pricing will encourage the proper amount of end-use conservation in the sense that no electricity will be consumed when its value to the consumer is less than the value of the resources required to produce it."

Estimates of the magnitude of electric load reduction by conservation are given in Appendix C, Volume IV, of the report "The Magnitude and Regional Distribution of Needs of Hydropower" of the National Hydropower Study. To the extent that the peak energy required will be reduced, the effect of conservation will also serve to reduce the need for pumped storage.

The need for pumped storage as a means of meeting peak demands depends on the shape of the daily load curve. Measures that shift loads from peak periods to off-peak periods reduce the need for pumped storage. The biggest group of peak electric loads that can be shifted are in the residential category: water, space heating, and air conditioning loads.

The Harza Engineering report showed that the only significant savings in the residential area falls into two principal categories. The first of these (denoted by "Settings" in Table 3-7) is the set-back of furnace or water heater thermostats or the set-up of air-conditioner thermostats. The second category (denoted by "Improvements") is improved furnaces, air-conditioners, water heaters, and refrigerators. The estimated magnitudes of savings are shown in the table. The effects of improvement in equipment are not expected to change the shape of the daily load curve; however, changing thermostat settings should reduce the peak loads in both summer and winter. The study also estimates a reduction in industrial use of electricity of approximately 20 percent and a reduction in the commercial sector of approximately 45 percent.

Another effect that can be and has been studied by this method is the shift of space heating and hot water heating from gas- and oil-fired heaters to electricity.

TABLE 3-7

Effect of Energy Conservation Measures
(percent decrease from base-case consumption)

NERC Region	Settings	Improvements
WSCC	12-19	11-17
MARCA	12	15
SWPP	13	17
EPCOT	13	17
SERC	19	12-13
MAAC	12	15
NPCC	10-15	12-16
MAIN	10	13
ECAR	10	13

Such a shift may not change total energy consumption very much if the new heater is a heat pump; it will increase total energy consumption, however, if the shift is to a resistance heater, but it will result in conservation of oil (or gas) at the expense of more plentiful resources. Some studies (52) consider the replacement of 24 percent of existing heaters and 29 percent of new heaters by heat pumps. If a shift to heat pumps without thermal storage or load control is made, utility peak loads will increase and load factors will decrease. If thermal storage or load controls are used, total system energy requirements will increase, and the effect on the load factor will depend on the amount of penetration. Moreover, the effects are likely to vary greatly from region to region. There are few data available on which to base an analysis or prediction of these effects. It is usual to follow the method used in the EPRI repot and assume a penetration, calculating the result. In that reference, the result as a large shift in the time of peak load, and the resulting load shape would provide plenty of opportunity for the use of system energy storage.

Load profiles for the residential, commercial, and industrial sectors are shown in Figures 3-6 through 3-9 from a study sponsored by EPRI (52). In that report load shapes were synthesized by adding the products of the ordinates from these figures and the peak value of the corresponding load components. Two typical results are shown in Figures 3-10 and 3-11. In both cases there is enough load shape variation remaining to make energy storage--including pumped storage--attractive.

The EPRI methodology can be used to determine whether the reductions of heating and cooling loads due to thermostat settings will shift enough load to reduce the need for pumped storage. An inspection of Figure 3-11 shows immediately that although conservation will slightly flatten the load shape, it will not reduce the need for energy storage significantly. To do so requires more than conservation--it requires load management.

The National Energy Conservation Policy Act (NECPA) also mandates the Residential Conservation Service (RCS) program. Under this program nearly all electric utilities (except some co-ops) are required to offer customers a detailed energy audit, including information the use of renewable resources. The auditor must explain any energy-conserving practices the customer could use and recommend installation of program measures (equipment, etc.) that would be effective in saving energy also giving information on costs, expected benefits, etc. The utility

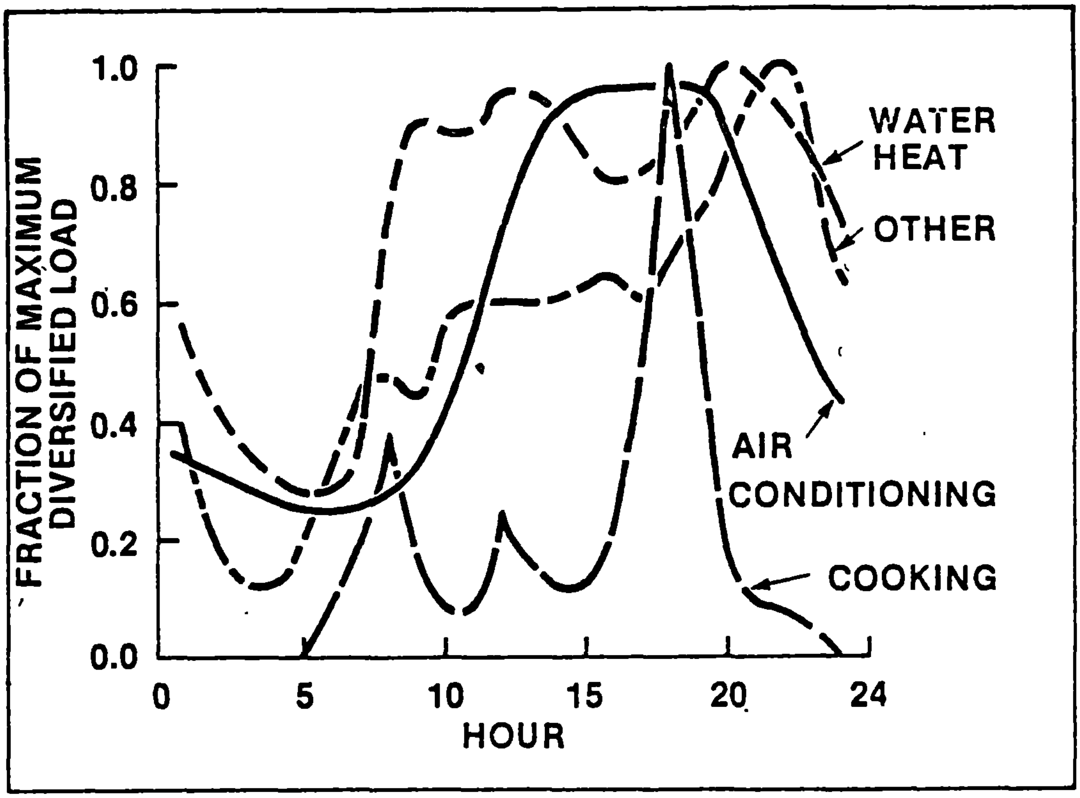


Figure 3-6 Load Profiles for Residential Sector - Summer

Source: 1) Air conditioning — Load Research Committee of AEIC (Alabama, 1970)

2) Water heat — Elements of Load, Potomac Electric, Item 1.22 (1959)

3) Cooking — Elements of Load, Potomac Electric, Item 1.21 (1959)

4) Other — Elements of Load, Potomac Electric, Item 1.11 (1959)

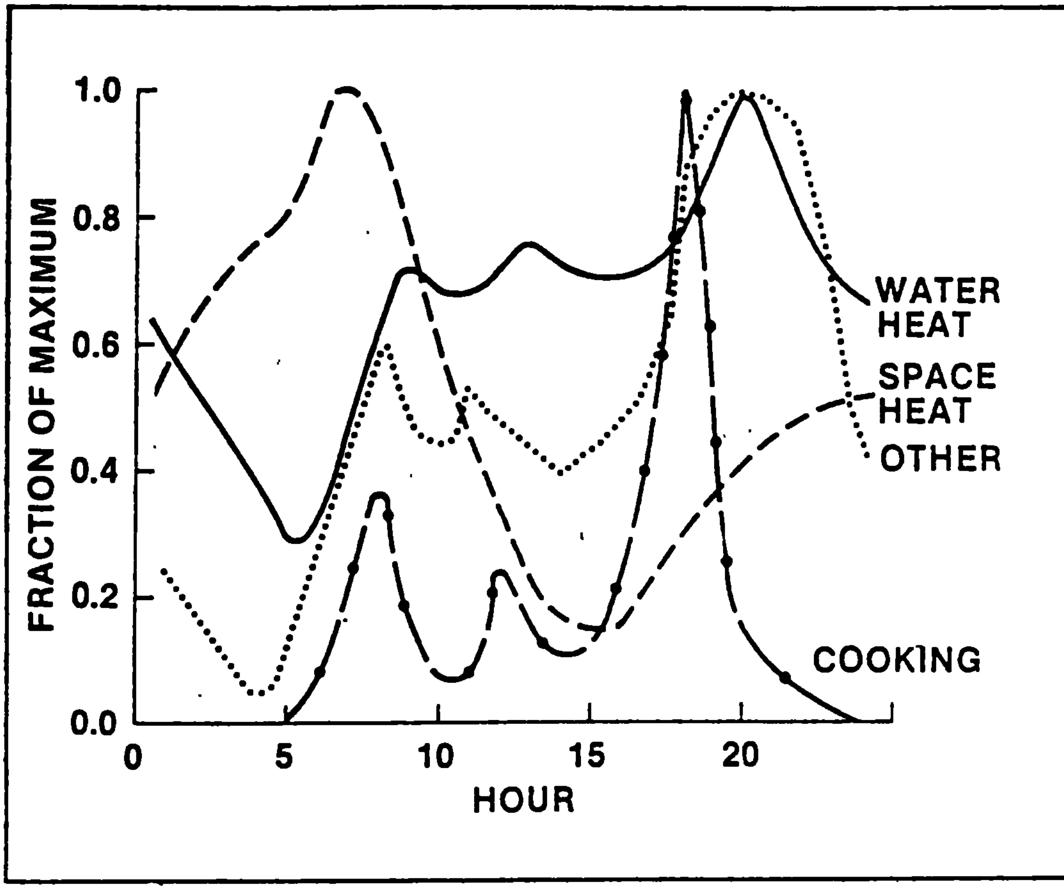


Figure 3-7 Load Profiles for Residential Sector - Winter

Source: 1) Space heat — Load Research Committee of AEIC (Alabama, 1972)
2) Water heat — Elements of Load, Potomac Electric, Item 1.22 (1959)
3) Cooking — Elements of Load, Potomac Electric, Item 1.21 (1959)
4) Other — Elements of Load, Potomac Electric, Item 1.11 (1959)

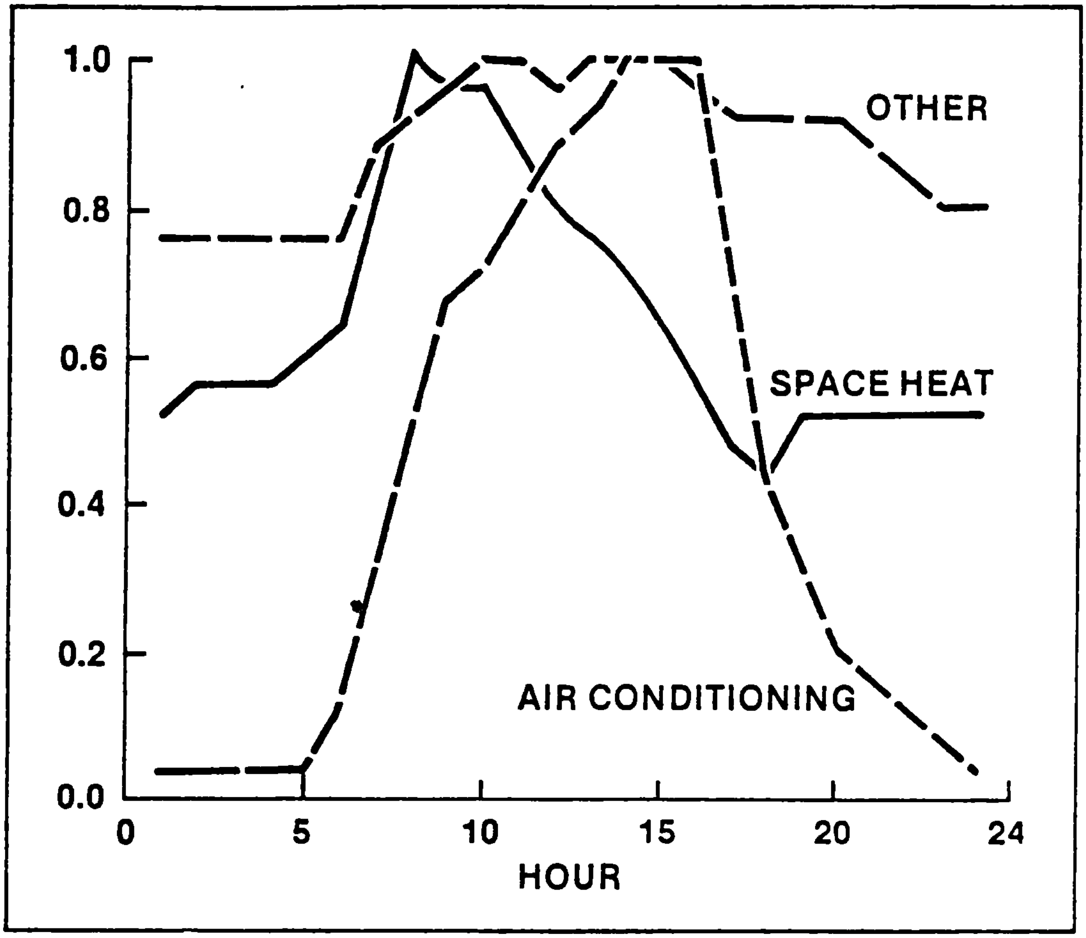


Figure 3-8 Representative Load Profile for Commercial Sector

Sources: 1) Space heat — Loau Research Committee of AEIC (Pennsylvania, 1971)

2) Air conditioning — Elements of Load, Potomac Electric (1959)

3) Other — Based on commercial load profiles during months when there is little heating or cooling demand

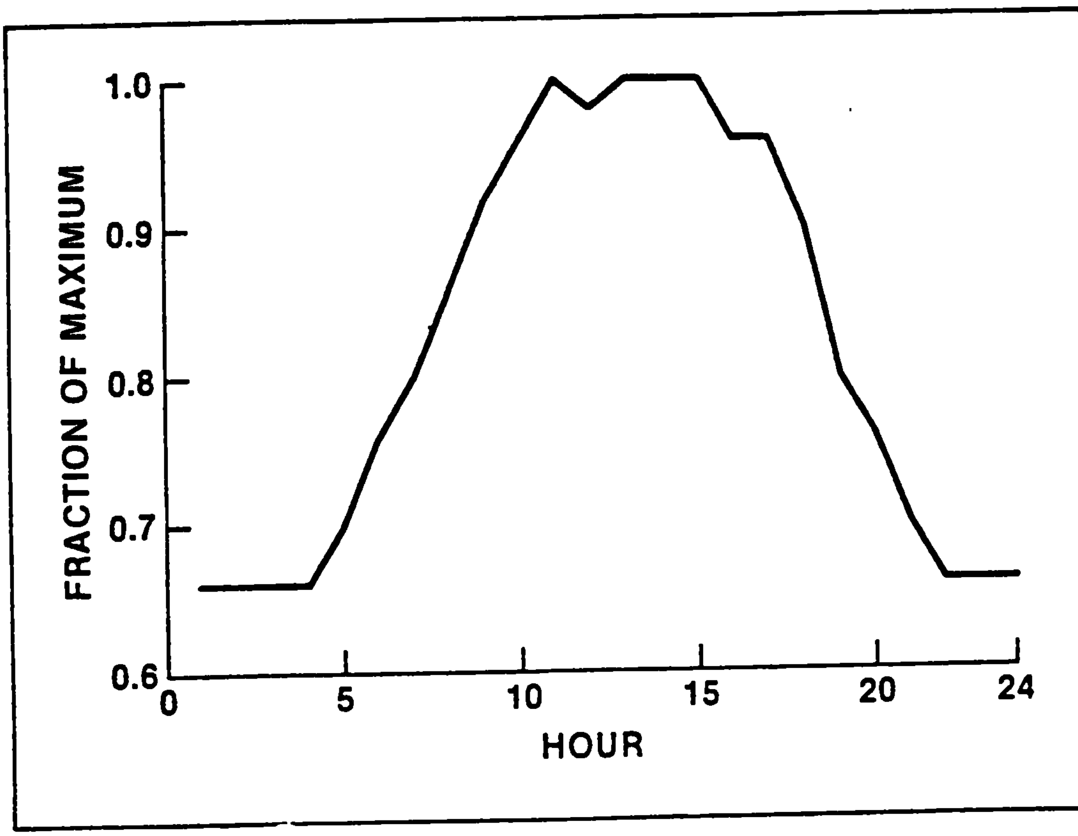


Figure 3-9 Representative Load Profile for Industrial Sector

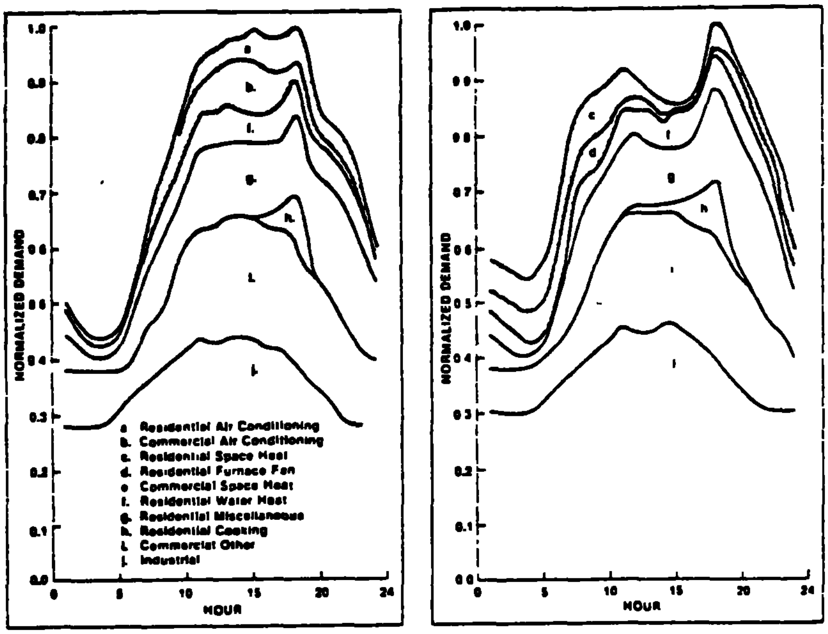


Figure 3-10 Typical load shapes for a normal summer day in the 1970s is shown on left. Load shape for a normal winter day in the 1970s is indicated on right.

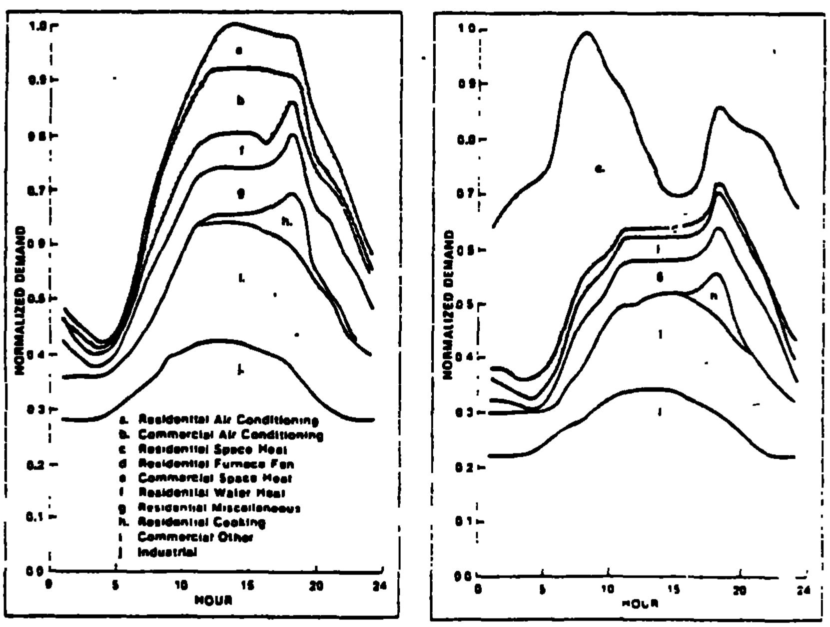


Figure 3-11 Typical Load shapes for normal days in the 1990s. Left shows summer day profile; right shows winter day profile.

also must arrange financing for the supply or installation of any such measure on a customer's request. In addition, the customer may pay for such measures on his utility bill. The program is estimates to cost utilities $4.9 billion or roughly 7 percent of total 1979 electric utility revenues. In many cases utilities have hired outside contractors to perform these audits. In some states the utilities have united to form an organization to conduct all audits in their state. Thus far the request rate for audits is estimated at 2 to 2-1/2 percent, and to be independent of the charge (if any) for the audit. (The response rate seems to depend more on the kWh price level.) Initial followup survèys show that although customers purport to be pleased with the audits that have been done, only about 20 percent of the measures recommended have been implemented. Even worse, two studies show that no energy was saved as a result of the services offered. After some experimentation, the most common survey technique involves use of a time-share computer because of the massive amounts of data required to offer energy audits once every 2 years through 1984. There is still a chance, however, that the popularity and effectiveness of the RCS program may grow.

Conservation measures most frequently recommended in a pilot audit program were:

Measure	Percent
Insulate pipes/ducts	56
Insulate walls	51
Aquastat	42
Tighten doors/windows	39
Automatic flue dampener	38
Replace/tune-up burner	38
Solar water heating	34
Install storm windows	30

The measures recommended in the average audit report were estimated to cost $1,228 and produce an average first-year savings of $317 (53).

As the cost of electricity rises there is new incentive to improve the efficiency of electric motors. (One estimate is that energy loss in motors is equivalent to 200,000 barrels of oil per day, or about 1.2 percent of U.S. consumption in 1980 (54, 55).) Energy-efficient motors with more steel and more copper to reduce internal losses are now commercially available, but they cost up to 25 percent more than standard motors. Even though efficiency is increased by only a few percent (say, from 91.5 percent to 94.5 percent), these motors will pay for themselves within only a few years. Moreover, a power-factor controller for small induction motors has been developed and offers energy savings ranging from 5 percent to 50 percent, depending on loadings.

As a means of forcing conservation of electricity, the Energy Policy and Conservation Act of 1975 mandated a 20-percent improvement in 1980 over similar products made in 1972 for 10 designated appliances. In 1978 the National Energy Conservation Policy Act (NECPA) required DOE to establish a mandatory, minimum-energy-efficiency standards program by December 1980 for:

Refrigerators	Clothes dryers
Freezers	Water heaters
Dishwashers	Room air conditioners
Furnaces	

These appliances are estimated to use 3/4 of the energy used in the home, which in turn is a little less than 20 percent of total U.S. consumption. This program is said to have greatly increased the energy efficiency and cost of appliances since 1972. Since most of the electricity used in the home is for space and water heating, the potential for saving large amounts of energy in other appliances is very small (56).

The principal result of conservation is expected to be an overall reduction in the quantity of energy used. EPRI (57) estimates that more efficient electricity use by all types of consumers could reduce electricity energy demand some 20 percent by the year 2000. Reductions in electrical system losses may be the most significant step toward conservation a utility can take, since a 1 percent reduction in transmission and distribution (T&D) system losses could save $1.1 billion by 1985.

The effects of the three demand alternatives (thermal storage, load management, and conservation) are shown on a hypothetical weekly load cycle in Figure 3-12. Here it is assumed that these measures are widely adopted throughout the service area. Load management or thermal storage will reduce peak loads and add to minimum loads; the effect is to flatten the peaks and fill in the valleys in the load curve. The result will be a reduction in the requirements for peaking plants such as pumped storage. Both the total peaking capacity and the percentage of system capacity in peaking plants will be reduced. Conservation will reduce loads generally without much effect on the shape of the load cycle plot. It will

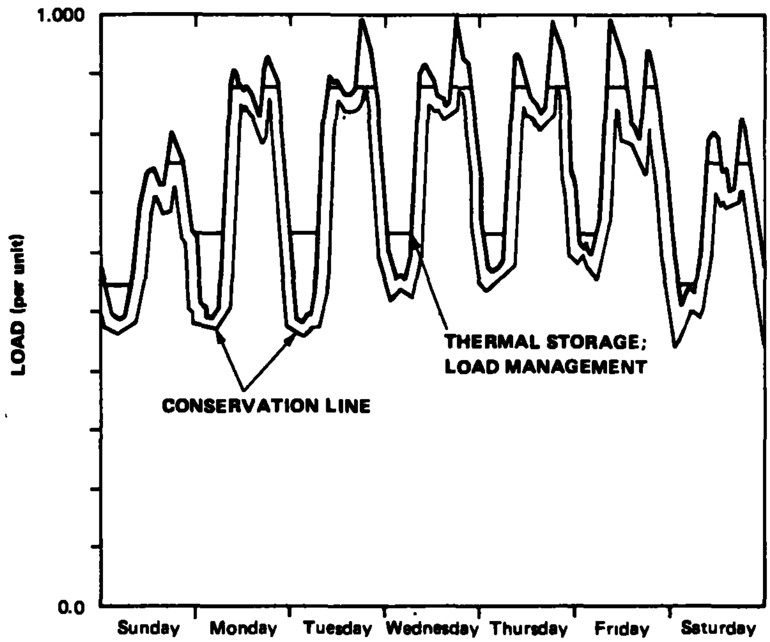


FIGURE 3-12
EFFECT OF DEMAND ALTERNATIVES
ON WEEKLY LOAD CYCLE

reduce total generating system capacity required, but will not change the percentage of system capacity in peaking plants.

REFERENCES

1. Conceptual Design of Thermal Energy Storage Systems for Near-Term Electric Utility Applications, Volumes 1 & 2, EPRI EM-103/Project 1082-1, Electric Power Research Institute prepared by General Electric Company, Schenectady, N.Y. (April 1979).

2. Conceptual Design of Thermal Energy Storage Systems for Near-Term Electric Utility Applications, EPRI EM-1218 Project 1082-1 Final Report, Electric Power Research Institute prepared by General Electric Company, Schenectady, N.Y. (November 1979).

3. F.R. Kalhammer, "Energy-Storage Systems," Scientific American, Vol. 241 (December 1979).

4. C.F. Miller, "A Discussion of Energy Alternatives," paper presented before the South Columbia River Basin Irrigation District, Wenatchee, Washington (October 19, 1979).

5. Conceptual Design for a Pilot/Demonstration Compressed Air Storage Facility Employing a Solution-Mined Salt Cavern, EPRI EM-391, prepared by General Electric Company for the Electric Power Research Institute, Palo Alto, California (June 1977).

6. "Eight Atmospheres in Reserve," EPRI Journal, 4, 3 (April 1979).

7. Technical and Economic Assessment of Advanced Compressed Air Storage (ACAS) Concepts, EM-1289, prepared by Central Electricity Generating Board, Southampton, England for the Electric Power Research Institute, Palo Alto, California (December 1979).

8. Development of Advanced Batteries for Utility Application, EPRI EM-1341, prepared by General Electric Company for the Electric Power Research Institute, Palo Alto, California (February 1980).

9. "Comparative Evaluation of New Electric Generating Technologies," Energy Technology VII, Government Institutes, Inc. (April 1979).

10. Assessment of Alternate Technologies for Utility Baseload Generating Capacity in New England, Energy Research Group, Inc. for New England Power Company, Westborough, Massachusetts (January 1979).

11. P. Bolan and L.M. Handley, "First Generation Fuel Cell Power Plant Characteristics," Power Systems Division, United Technologies Corporation, Hartford, Connecticut (undated).

12. W.M. Burnett, "Fuel Cell Benefits--The Program Management Office Viewpoint," paper presented at the ERDA-EPRI National Fuel Cell Symposium, Palo Alto, California (June 1976).

13. Economic Assessment of the Utilization of Fuel Cells in Electric Systems, EPRI EM-366, Public Service Electric and Gas Company in New Jersey for

the Electric Power Research Institute, Palo Alto, California (November 1976).

14. Estimates of National Hydroelectric Power Potential at Existing Dams, U.S. Army Corps of Engineers, Institute for Water Resources (July 1977).

15. Preliminary Inventory of Hydropower Resources (six volumes), National Hydroelectric Power Resources Study, U.S. Army Corps of Engineers, Institute for Water Resources and the Hydrologic Engineering Center (July 1979).

16. A.W. Eipper, "Possible Impacts of Hydroelectric Developments on Fish and Wildlife," Waterpower '79, Abstracts of International Conference on Small-Scale Hydropower, October 1-3, 1979, U.S. Government Printing Office.

17. Hydropower--An Energy Source Whose Time Has Come Again, EMD-80-30, U.S. Government Printing Office (January 11, 1980).

18. Domestic Potential of Solar and Other Renewable Energy Source, Report of the Solar Resource Group, Supply and Delivery Panel, Committee on Nuclear and Alternative Energy Systems, National Research Council, National Academy of Sciences, Washington, D.C. (1979).

19. R. Gale, "Combined Cycle Bonanza," The Energy Daily (October 31, 1980).

20. P.J. Margaritis and R.M. Strausky, "Westinghouse to Launch Coal Gasifier with Combined Cycle Unit," Energy International, Vol. 17 (March 1980).

21. "Advanced Gas Turbine Not Needed for Coal Gas/Combined Cycle: EPRI," Electric Light and Power, Vol. 57 (May 1979).

22. I.A. Forbes, "Testimony on the Availability of Alternate Energy Sources for the Massachusetts Municipal Wholesale Electric Company," Energy Research Group, Inc., Waltham, Massachusetts (January 1980).

23. Technical Assessment Guide, EPRI PS-1201-SR, Electric Power Research Institute, Palo Alto, California (July 1979).

24. Cogeneration Technology Alternatives Study (CTAS): United Technologies Corporation Final Report, DOE/NASA/0030-80/1, United Technologies Corporation for the National Aeronautics and Space Administration for the U.S. Department of Energy, Washington, D.C. (January 1980).

25. "Cogeneration," Power Engineering, 82, 3, pp. 34-42 (March 1978).

26. The Potential for Cogeneration Development in Six Major Industries by 1985, Resource Planning Associates, Cambridge, Massachusetts (December 1977).

27. EPRI New Energy Resources Department Strategy Paper, EPRI ER-979-SY, Booz, Allen and Hamilton, Inc. for the Electric Power Research Institute, Palo Alto, California (January 1979).

28. Solar Energy: A Status Report, DOE/ET-0062, U.S. Department of Energy, Washington, D.C. (June 1978).

29. The Potential for Solar Energy Utilization in Southern New England, Arthur D. Little, Inc., Cambridge, Massachusetts (1979).

30. C.G. Justus, "Wind Energy Statistics for Large Arrays of Wind Turbines (New England and Central U.S. Region)," Solar Energy, 20, 5, pp. 379-386 (May 1978).

31. Requirements Assessment of Wind Power Plants in Electric Utility Systems, EPRI ER-978, General Electric Company for the Electric Power Research Institute, Palo Alto, California (January 1979).

32. Draft Environmental Impact Statement, Wind Turbine Generator System, Block Island, Rhode Island, DOE/EIS-0006-D, U.S. Department of Energy, Washington, D.C. (March 1978).

33. U.S. Energy Supply Prospects to 2010, Report of the Supply and Delivery Panel to the Committee on Nuclear and Alternative Energy Systems, National Research Council, National Academy of Sciences, Washington, D.C. (1979).

34. Energy from the Ocean, Science Policy Research Division, Congressional Research Service, Library of Congress, Washington, D.C. (April 1, 1978).

35. A. Mitsui, S. Miyachi, A. San Pietro and S. Tamura, editors, Biological Solar Energy Conversion, Academic Press, New York (1977).

36. System Descriptions and Engineering Costs for Solar-Related Technologies, Vol. IX, Biomass Fuels Production and Conversion Systems, MTR-7485, The MITRE Corporation, METREK Division (June 1977).

37. J. Catron, "Putting Baseload to Work on the Night Shift," EPRI Journal, Vol. 5, No. 3, April 1980.

38. John Platts, "Electrical Load Management: The British Experience" IEEE Spectrum (February 1979 and April 1979).

39. R.H.S. Hardy, M.T. Sulatisky and W.B.H. Cooke, "Residential Heat Storage Furnaces for Load Management--Design and Control," Power Apparatus and Systems, Vol. PAS-99, No. 2 (March/April 1980).

40. W.R. Coleman, "Customers Give Thermal Storage a Big OK," Electrical World (May 1, 1980).

41. Charles Smith, "Load Management Activities Jump Sharply," Electrical World (July 1, 1980).

42. "Energy on the Horizon," EPRI Journal (May 1979).

43. Public Law 95-617.

44. "Reference Manual and Procedures for Implementing PURPA," Electric Utility Rate Design Study Report #82, Palo Alto, California (March 1979).

45. Electricity Demand and Consumption by Time-of-Use Survey, EPRI EA-1294 Electric Power Research Institute, Palo Alto, California (December 1979).

46. S.P. Reynolds and T.E. Creighton, Jr., "Time of Use Rates for Very Large Customers of the Pacific Gas & Electric Co. Systems," Power Apparatus and Systems, Vol. PAS-99, No. 5 (January/February 1980).

47. M.D. Nelson, "Minnkota's Load Management Program: Economic Aspects," Power Apparatus and Systems, Vol. PAS-99, No. 5 (September/October 1980).

48. C.R. Hudson, "Effects of Residential Load Management on Electric Utility Generation Expansion and Cost," unpublished, Oak Ridge National Laboratory (1980).

49. M.A. Kuliasha, "A Dynamic Model of Power System Operation Incorporating Load Control," Oak Ridge National Laboratory Report ORNL-5655 (October 1980).

50. S.M. Barrager and G.L. Campbell, "Analysis of the Need for Intermediate and Peaking Technologies in the Year 2000," U.S. Department of Energy Report DOE/RA/29999-01 (April 1980).

51. "Building Design Cuts Energy Use 40%," Electrical World (September 1, 1980).

52. Integrated Analysis of Load Shapes and Energy Storage, EPRI EA-970 Electric Power Research Institute, Palo Alto, California (March 1979).

53. "DOE Spells Out Its Home-Audit Rule," "Utilities Tackle RCS Audit Problem," "Energy Audits Generate Many Questions," Electrical World, January 1, 1980; August 1, 1980; December 1980.

54. "New Approved Cut Motor KWH Use," Electrical World (September 1, 1980).

55. "Motor Efficiency Can Bring Big Savings," Electrical World (November 1980).

56. "Appliance Energy Labeling Takes Effect," Electrical World (June 1, 1980).

57. 1981-1985 Overview & Strategy, Electric Power Research Institute, EPRI Document P1700SR (October 1980).

58. Final Report on Tidal Power Study for the U.S. Energy Research and Development Administration, Report No. DGE/2293-3, Stone & Webster Engineering Corporation, Boston, Massachusetts (March 1977).

4.0 FUTURE DEVELOPMENT OF PUMPED STORAGE

The future development of pumped storage systems will be affected by the need to add new generating capacity to the Nation's electrical system and the overall competitiveness of alternatives to pumped storage. The alternatives may compete on several different levels. Economic considerations are probably most significant, but technical limitations, environmental impacts, physical constraints, and institutional/regulatory impacts also play an important role in determining the competitive advantages and disadvantages of any supply technology. Section 4.1 represents a comparative assessment of the alternative supply technologies and provides an estimate of future potential generating applications and capacity. Section 4.2 compares the physical, economic, and institutional/regulatory constraints and environmental impacts associated with pumped storage systems and each alternative technology. The major economic, physical, and environmental factors affecting the future development of pumped storage systems are discussed in Section 4.3.

4.1 COMPARATIVE ASSESSMENT OF THE ALTERNATIVES

This section summarizes the principal characteristics of Categories A and B supply alternative technologies and discusses their competitiveness for peak-load operation. Their competitiveness is influenced by economic costs, technical limitations, availability, and potential utility applications. Sections 4.1.1 through 4.1.3 compare the technologies while Section 4.1.4 summarizes the characteristics of each technology and its regional availability, and estimates its future potential generating application and capacity.

4.1.1 Category A--Storage Technologies

Three storage technologies other than pumped hydro were considered in Category A: utility thermal storage, compressed air storage, and advanced batteries.

Utility thermal storage has been studied quite extensively over the last several years. While no major technical barriers to development of the most promising methods of thermal storage are foreseen, projected capital costs of near-term design concepts still appear to be too high to be economically competitive for peak-load or cycling operation. Currently, plans to develop thermal storage for incorporation into utility plants are limited to pilot and demonstration solar thermal electric facilities.

Compressed air storage (CAS) has significant potential as a means of peak power production. The only CAS plant currently in operation is the 290-megawatt (MW) facility at Huntorf, West Germany. Studies conducted to date generally project potentially competitive economic costs, and suggest no major technical barriers to development other than location of acceptable geologic media for large air storage caverns. CAS is not a true storage technology since release of compressed air provides only about two-thirds of the power generated; the remainder is provided by distillate oil or natural gas burned in a combustion turbine. While no CAS units are currently planned in the United States, ongoing studies could lead to commercial demonstration units by around 1990.

Batteries may become an alternative for dispersed load-leveling use by utilities if current research and development efforts to produce advanced battery designs are successful. It is difficult to predict whether advanced batteries of adequate durability and sufficiently low cost for utility application will be available within the study time-frame (1980-2000). However, several organizations indicate that it may be possible to have advanced battery systems in commercial operation by around 1992. Meeting this target date, however, will require significant technical development and demonstration, and substantial cost reduction.

Unlike hydroelectric pumped storage, none of these alternatives are mature, demonstrated technologies. While compressed air storage and advanced batteries show good potential for peak-load operation, their commercial availability for deployment in utility systems is at least 5 to 10 years away.

4.1.2 Category A--Other Peak-Load Generation Technologies

The other peak-load generation technologies considered in Category A were: diesels and combustion turbines, phosphoric acid (first-generation) fuel cells, hydroelectric power, and solar photovoltaic energy conversion.

Diesels and combustion turbines are, and will continue to be, major options for peak-load power production. They are attractive because of their short construction lead time and relatively low capital cost. Although they use primarily distillate oil and natural gas, the Powerplant and Industrial Fuel Use Act of 1978 exempts new oil and gas units operating less than 1,500 hours per year. The premium fuels they use will continue to become increasingly expensive and supply constrained, although coal-derived and other unconventional fuels may provide an economical alternative in the 1990's.

Phosphoric acid (first-generation) fuel cells are currently in the early demonstration stages. They offer significant advantages over diesels and combustion turbines, including higher efficiency, constant efficiency over a wide range of power output, lower emissions, and the potential for dispersed siting. However, they will require the same premium fuels, and startup and shutdown characteristics are not as yet ideal for peak-load operation. Fuel cells are not commercially available, but could be in production by the mid 1980's. However, capital costs must be reduced substantially from current levels; estimated capital costs for production units are considerably higher (around 100 to 200 percent) than for combustion turbines.

Hydroelectric power is currently an important source of peak- and intermediate-load power generation. The physical potential of undeveloped hydroelectric resources in the United States is estimated to be much larger than that already developed. The principal focus of the National Hydropower Study by the U.S. Army Corps of Engineers is to catalogue this potential and to analyze the technical, economic, environmental, and institutional constraints to its development. While the developable potential will be substantially less than the physical limits of undeveloped potential (due, for example, to economic constraints), new hydroelectric capacity will be an option for peak- and intermediate-load power in most areas of the country for some time to come.

Solar photovoltaic energy conversion is constrained by its high current capital cost. The Department of Energy's (DOE's) target is to reduce costs of complete photovoltaic systems for utility application to $1,100 to $1,800 per peak kilowatt (kW) by 1990 (in 1980 dollars). Meeting these goals will, at a minimum, require considerable engineering development. Photovoltaic systems, however, are not a true peak-load technology. Their output on a clear day corresponds closely to the peak demand profile in summer, but on overcast days and in winter they cannot provide full capacity on peak without storage. It is estimated that the effective capability of photovoltaic systems is on the order of 35 percent of their rated capacity, and their capacity factor would generally range from around 14 to 30 percent, depending on location and collector geometry.

Overall, combustion turbines and hydroelectric power will continue to be major options for new peak-load power generation over the next two decades. If substantial reductions in capital cost can be achieved, fuel cells have the potential to become a viable alternative in the 1990's. Photovoltaic energy conversion is likely to be limited to a small supplemental role between now and 2000.

4.1.3 Category B--Supply Technologies

The following technological alternatives for intermediate-load power generation were evaluated under Category B: oil plant conversion, combined-cycle, coal gasification/combined-cycle (CGCC), fluidized bed combustion, cogeneration, solar thermal energy conversion, wind turbines, tidal plants, and biomass powerplants.

Oil-fired (and gas-fired) steam generating plants still account for a significant portion of total power generation in the United States. Many of these were originally designed for coal firing, though some more recent units were designed solely for oil firing. Conversion to coal can significantly reduce operating costs; however, the economic feasibility of conversion is sensitive to such factors as a plant's age, whether or not it has operable coal handling equipment and boilers, and the additional emissions control equipment required. Converted plants could be operated as intermediate-load units, but are more likely to be operated as base loaded. Such conversions do not, of course, provide new capacity, and could actually enhance the potential for pumped hydroelectric storage rather than compete with it.

Combined-cycle units are ideally suited to intermediate-load operation. They have the highest efficiency of current thermal power generation technologies and a capital cost intermediate between that of combustion turbine peaking units and coal-fired base-load units. A substantial number of combined-cycle units are currently in operation, under construction, or on order. However, inasmuch as current designs use primarily distillate oil or natural gas, future deployment could be constrained by the limit imposed by the Powerplant and Industrial Fuel Use Act of 1978 of no more than 1,500 hours per operation for new oil and gas units.

Coal gasification/combined-cycle (CGCC) plants that integrate a coal gasifier with a combined-cycle unit offer many of the advantages of combined-cycle operation together with a clean method of using coal. The 100-MW Cool Water Project in California will be the first CGCC demonstration unit in the United States, and it is estimated that commercial units could be in operation as early as

1990. The capital costs of commercial CGCC plants are projected to be quite close to those of conventional coal-fired plants with scrubbers. While technically suitable for intermediate-load operation, CGCC units are likely to be used for base-load power generation in their initial years of operation because of their relatively high capital cost.

Fluidized bed combustion likewise offers the advantages of higher efficiency and reduced emissions as compared to conventional coal-fired units. Demonstration atmospheric fluidized bed combustion (AFBC) units are planned, and it is estimated that commercial plants could be in operation as early as 1992. While intermediate-load operation is technically possible, the projected capital costs of commercial units are quite close to those for conventional coal-fired plants. Thus base-load generation in the initial years of operation is likely.

Cogeneration of electricity and process heat or steam at industrial facilities can provide supplemental amounts of new power generation, particularly in major industrial areas. Much of the cogenerated power will be consumed internally by industrial facilities, and the impact is seen by utilities essentially as a demand reduction. Excess power will be sold to utilities at a price based on what it would otherwise cost the utilities to generate the power themselves. Thus, cogeneration will have little or no impact on what other consumers pay for electricity. Operation in the intermediate-load range is possible, but it can be expected that much cogenerated power will be base loaded.

Solar thermal power generation is currently in the early demonstration stages. Capital costs will have to be reduced substantially from current levels, concentrating primarily on reducing heliostat costs by 70 or 80 percent. If this can be achieved, commercial units costing around $1,700/kW could be possible in the 1990's. Deployment would be limited, at least initially, to the Southwest. Solar thermal electric plants would be designed for load-following operation on clear days; backup capacity onsite or elsewhere in the system would be required on overcast days. The future economic viability of solar thermal electric plants is uncertain, and substantial research and development work is still required.

Wind power is likewise in the early demonstration stage. A variety of prototype and demonstration wind turbines are in operation or under construction as part of the Department of Energy/National Aeronautics and Space Administration (DOE/NASA) and industry programs. Significant cost reductions will need to be achieved through development work and mass production savings. It is estimated that the installed capital costs of current designs in volume production could be as low as $800/kW (referenced to a rating in 30-mph winds). Capacity factor estimates generally range from 20 to 45 percent, depending on design and location. Since wind power is intermittent, the principal value of wind turbines is in the fuel use they displace in the system. Capacity value is highly variable; estimates of effective capability for large wind turbine arrays range from 5 to 40 percent of rated capacity. The future economic viability of wind energy conversion in utility systems is still quite uncertain, but between now and the year 2000 it will probably have only a limited impact.

Tidal power potential in the United States is limited to the Passamaquoddy Bay region in Maine (and New Brunswick, Canada) and the Cook Inlet region in Alaska. Currently, there are no plans for development. Given the high capital costs and long construction times (estimated to range from 4 to 10 years), it is unlikely that any significant amount of tidal capacity would be available in the United States before 2000.

Biomass resources in the United States, composed of standing trees and logging, mill, and crop residues, have a theoretical potential on the order of a 50,000-MW equivalent. The developable potential is substantially less, however, due to recovery feasibility; economic, environmental, and other constraints; and competing demands. Estimated prices of green wood chips and biomass waste fuels are economically competitive with other boiler fuels, but the capital costs of wood-fired steam plants are significantly higher than those of large coal-fired plants (this is largely due to their relatively small size of from 10 to 50 MW). While several wood-fired units are in operation and several more are planned, wood and other biomass will be limited to a supplemental role in future electric power generation.

Existing oil- and coal-fired units will continue to be used for intermediate-load power generation. Hydroelectric power will continue to be a major option for new intermediate-load capacity as well as for peak loads. Combined-cycle units are ideally suited to intermediate-load operation, but new orders may be constrained by limitations imposed by the Fuel Use Act. Coal gasification/combined-cycle and fluidized bed combustion units could be commercially available in the early 1990's. While capable of intermediate-load power generation, they will likely be used for base-load generation in their initial years of operation due to their relatively high capital cost. Other technologies such as cogeneration, solar thermal electric plants, wind turbines, and biomass plants probably will provide some additional capacity.

4.1.4 Summary Tables

Tables 4-1 through 4-16 summarize the supply alternatives to pumped storage systems. Capital costs given in these tables are estimates of total costs complete in 1980 dollars. They include not only base construction costs but allowances for engineering services, contingencies, interest costs, etc., to reflect the total capital cost for a hypothetical startup in mid-1980 (though projected real cost decreases from current levels have been incorporated for technologies that are not yet commercial). Care should be exercised in comparing these estimates to others in the literature that may not necessarily include all of these cost components. The "First Commercial Service" date given in the tables includes design and licensing time plus the lead time estimated from the first commercial availability date.

Table 4-17 summarizes the regional availability of the alternative supply technologies, and Table 4-18 gives projections of the potential penetration of Categories A and B alternative supply technologies for 1985, 1990, 1995, and 2000. These projections assume the commercialization of new technologies in line with target schedules.

Not all of this capacity would be available for firm peak-load and intermediate-load power generation. As noted in Table 4-18, most of the projected oil plant conversion, coal gasification/combined-cycle, fluidized bed, cogeneration, and biomass capacity would be operated as base loaded, at least through the study time-frame. Additionally, the effective capability of solar and wind capacity (and possibly some of the hydroelectric capacity) would be substantially less than the rated capacity. These technologies account for the major portion of the projected capacity, and thus, of the levels forecast for the year 2000, around 20 to 40 gigawatts (GW) would be firm peak-load and intermediate-load capacity--about evenly divided between the two load ranges. These levels, which will develop mainly in the 1990's, could be further reduced by intertechnology competition and by slippage in commercialization schedules.

TABLE 4-1

Summary Assessment of Utility Thermal Storage

TECHNOLOGY: Utility Thermal Storage

Load Type:	Peak
Fuel:	Plant heat
Status:	Under investigation

DEPLOYMENT SCHEDULE

First Commercial Service:	N/A
Lead Time:	Same as for plant in which it is incorporated
Unit Life:	Same as for plant in which it is incorporated

PRINCIPAL DEPLOYMENT FACTORS

Technological:	Capital cost currently too high
Resource:	Any thermal generating unit
Regionality:	None
Environmental:	Not significant
Institutional:	--

COST AND PERFORMANCE DATA

Capital Cost ($/kW):	85-200 (6-hour discharge)
O&M Cost (¢/kWh)*:	N/A
Heat Rate or Efficiency:	75-90 percent
Capacity Factor:	N/A

*Operation and Maintenance Cost (cents per kilowatt-hour).

TABLE 4-2

Summary Assessment of Compressed Air Storage

TECHNOLOGY: Compressed Air Storage

Load Type:	Peak
Fuel:	Electricity for pumping; oil or natural gas during discharge
Status:	Prototype operating in West Germany

DEPLOYMENT SCHEDULE

First Commercial Service:	1988
Lead Time:	6-10 years
Unit Life:	20-30 years

PRINCIPAL DEPLOYMENT FACTORS

Technological:	Uncertainties in geological requirements and thermal-physical behavior of storage caverns
Resource:	Requires premium fuel for operation, though 60 to 70 percent less than a conventional gas turbine
Regionality:	Some areas do not have suitable geologic formations (see Figure 3-5)
Environmental:	Emissions and underground excavation
Institutional:	Potential future restrictions on oil and gas use

COST AND PERFORMANCE DATA

Capital Cost ($/kW):	270-480 (6- to 8-hour discharge)
O&M Cost (¢/kWh)*:	0.2
Heat Rate or Efficiency:	0.72-0.83 kWh/kWh electricity and 4,000-5,300 Btu/kWh fuel
Capacity Factor:	15 percent (typical)

Note: Low end of capital cost range applies to salt caverns, high end to hard rock caverns.

*Operation and Maintenance Cost (cents per kilowatt-hour).

TABLE 4-3

Summary Assessment of Advanced Storage Batteries

TECHNOLOGY: Advanced Storage Batteries

Load Type:	Peak
Fuel:	Electricity
Status:	Research and development

DEPLOYMENT SCHEDULE

First Commercial Service:	1992
Lead Time:	2 years
Unit Life:	10-15 years

PRINCIPAL DEPLOYMENT FACTORS

Technological:	Requires substantial cost reduction and component lifetime improvements
Resource:	Off-peak power
Regionality:	None
Environmental:	Potential accidental release of toxic materials
Institutional:	--

COST AND PERFORMANCE DATA

Capital Cost ($/kW):	400-700 (5-hour discharge)
O&M Cost (¢/kWh)*:	0.15-0.25
Heat Rate or Efficiency:	72 percent
Capacity Factor:	Less than 15 percent

Note: Low end of capital cost range is commercial goal.

*Operation and Maintenance Cost (cents per kilowatt-hour).

TABLE 4-4

Summary Assessment of Combustion Turbines

TECHNOLOGY: Combustion Turbines

Load Type:	Peak
Fuel:	Oil or natural gas
Status:	Available

DEPLOYMENT SCHEDULE

First Commercial Service:	Current
Lead Time:	2 years
Unit Life:	20 years

PRINCIPAL DEPLOYMENT FACTORS

Technological:	Advantages are low capital cost and short lead time
Resource:	Uses premium fuels
Regionality:	None
Environmental:	Emissions
Institutional:	Potential future restrictions on oil and gas use

COST AND PERFORMANCE DATA

Capital Cost ($/kW):	215-250
O&M Cost (¢/kWh)*:	0.3
Heat Rate or Efficiency:	13,800-12,500 Btu/kWh (annual average)
Capacity Factor:	15 percent or less

Note: High capital cost and low heat rate are for an advanced design potentially available in the mid- to late-1980's.

*Operation and Maintenance Cost (cents per kilowatt-hour).

TABLE 4-5

Summary Assessment of First-Generation Fuel Cells

TECHNOLOGY: First-Generation Fuel Cells

Load Type:	Intermediate/peak
Fuel:	Light distillate oil or natural gas
Status:	Prototype

DEPLOYMENT SCHEDULE

First Commercial Service:	1986
Lead Time:	2 years
Unit Life:	20 years

PRINCIPAL DEPLOYMENT FACTORS

Technological:	Startup and shutdown characteristics are not as yet ideal for peak-load operation; requires improvements in component lifetime and significant cost reduction
Resource:	Uses premium fuels
Regionality:	None
Environmental:	Potential air emissions
Institutional:	Restrictions on oil and natural gas use

COST AND PERFORMANCE DATA

Capital Cost ($/kW):	400-700
O&M Cost (¢/kWh)*:	0.4-0.5
Heat Rate or Efficiency:	9,300 Btu/kWh
Capacity Factor:	35 percent (typical)

Note: Best estimate of capital cost is about $500/kW in full production.

*Operation and Maintenance Cost (cents per kilowatt-hour).

TABLE 4-6

Summary Assessment of Hydroelectric Power

TECHNOLOGY: <u>Hydroelectric Power</u>

Load Type:	All (project-specific)
Fuel:	--
Status:	Available

DEPLOYMENT SCHEDULE

First Commercial Service:	Current
Lead Time:	4-10 years
Unit Life:	50+ years

PRINCIPAL DEPLOYMENT FACTORS

Technological:	None
Resource:	Substantial
Regionality:	Large regional variation; greatest undeveloped potential in the Pacific Northwest (see Figure 3-9)
Environmental:	Project-specific (see Section 3.2.3.6)
Institutional:	Siting

COST AND PERFORMANCE DATA

Capital Cost (\$/kW):	500-2,000 (project-specific; see text)
O&M Cost (¢/kWh)*:	Variable
Heat Rate or Efficiency:	--
Capacity Factor:	Project-specific

*Operation and Maintenance Cost (cents per kilowatt-hour).

TABLE 4-7

Summary Assessment of Solar Photovoltaic

TECHNOLOGY: Solar Photovoltaic

Load Type:	Peak/fuel-saver
Fuel:	--
Status:	Research and development (available, but current costs are too high for widespread use)

DEPLOYMENT SCHEDULE

First Commercial Service:	1992
Lead Time:	2-5 years (higher figure is for large central station)
Unit Life:	20 years

PRINCIPAL DEPLOYMENT FACTORS

Technological:	Major cost reduction required
Resource:	Large
Regionality:	Capacity factor varies; highest in Southwest
Environmental:	Large land areas required; potential for a variety of chemical releases during manufacture of cells
Institutional:	--

COST AND PERFORMANCE DATA

Capital Cost ($/kW):	1,100-1,800
O&M Cost (¢/kWh)*:	1-3 percent per year of initial investment
Heat Rate or Efficiency:	--
Capacity Factor:	14-30 percent (see Table 3-11)

Note: Capital costs are DOE 1990 goals for complete systems. Effective capability is around 35 percent of rated capacity.

*Operation and Maintenance Cost (cents per kilowatt-hour).

TABLE 4-8

Summary Assessment of Oil Plant Conversion

TECHNOLOGY: Oil Plant Conversion

Load Type:	Base/intermediate (likely to be mostly base loaded in study time-frame)
Fuel:	Coal (and wastes)
Status:	Available

DEPLOYMENT SCHEDULE

First Commercial Service:	Current
Lead Time:	--
Unit Life:	Plant-specific

PRINCIPAL DEPLOYMENT FACTORS

Technological:	Feasibility sensitive to type and age of unit (see Section 3.4.1)
Resource:	--
Regionality:	--
Environmental:	Emissions
Institutional:	Conversion orders; requirements for additional control equipment

COST AND PERFORMANCE DATA

Capital Cost ($/kW):	Highly plant-specific (see text)
O&M Cost (¢/kWh)*:	--
Heat Rate or Efficiency:	--
Capacity Factor:	--

*Operation and Maintenance Cost (cents per kilowatt-hour).

TABLE 4-9

Summary Assessment of Combined-Cycle

TECHNOLOGY: Combined-Cycle

Load Type:	Intermediate
Fuel:	Oil or natural gas
Status:	Available

DEPLOYMENT SCHEDULE

First Commercial Service:	Current
Lead Time:	3 years
Unit Life:	30 years

PRINCIPAL DEPLOYMENT FACTORS

Technological:	Well suited for intermediate-load use
Resource:	Uses premium fuels
Regionality:	None
Environmental:	Emissions
Institutional:	Fuel Use Act restrictions

COST AND PERFORMANCE DATA

Capital Cost ($/kW):	380-470
O&M Cost (¢/kWh)*:	0.2-0.3
Heat Rate or Efficiency:	8,700-7,600 Btu/kWh (annual average)
Capacity Factor:	40 percent (typical)

Note: High capital cost and low heat rate are for residual oil use in an advanced design potentially available in the late 1980's.

*Operation and Maintenance Cost (cents per kilowatt-hour).

TABLE 4-10

Summary Assessment of Coal Gasification/Combined-Cycle

TECHNOLOGY: <u>Coal Gasification/Combined-Cycle</u>

Load Type:	Base/intermediate (likely to be mostly base loaded in study time-frame)
Fuel:	Coal
Status:	Demonstration unit planned

DEPLOYMENT SCHEDULE

First Commercial Service:	1990
Lead Time:	5 years
Unit Life:	30 years

PRINCIPAL DEPLOYMENT FACTORS

Technological:	Lack of experience with integrated system control, gas cleaning equipment design
Resource:	Large
Regionality:	None
Environmental:	Emissions, but lower than conventional coal units; waste disposal
Institutional:	--

COST AND PERFORMANCE DATA

Capital Cost ($/kW):	900 ± 75
O&M Cost (¢/kWh)*:	0.5
Heat Rate or Efficiency:	9,250 Btu/kWh (annual average)
Capacity Factor:	65 percent (typical)

*Operation and Maintenance Cost (cents per kilowatt-hour).

TABLE 4-11

Summary Assessment of Fluidized Bed Combustion (Atmospheric)

TECHNOLOGY: Fluidized Bed Combustion (Atmospheric)

Load Type:	Base/intermediate (likely to be mostly base loaded in study time-frame)
Fuel:	Coal
Status:	Pilot

DEPLOYMENT SCHEDULE

First Commercial Service:	1992
Lead Time:	5-6 years
Unit Life:	30 years

PRINCIPAL DEPLOYMENT FACTORS

Technological:	Requires further development and demonstration
Resource:	Large
Regionality:	None
Environmental:	Emissions, but lower than conventional coal units; waste disposal
Institutional:	--

COST AND PERFORMANCE DATA

Capital Cost ($/kW):	800 ± 100
O&M Cost (¢/kWh)*:	0.8
Heat Rate or Efficiency:	9,800 Btu/kWh
Capacity Factor:	65 percent (typical)

*Operation and Maintenance Cost (cents per kilowatt-hour).

TABLE 4-12

Summary Assessment of Cogeneration

TECHNOLOGY: Cogeneration	
Load Type:	Base/intermediate (likely to be mostly base loaded)
Fuel:	Oil, coal, or wastes
Status:	Available
DEPLOYMENT SCHEDULE	
First Commercial Service:	Current
Lead Time:	--
Unit Life:	20 years
PRINCIPAL DEPLOYMENT FACTORS	
Technological:	Project-specific (see Section 3.2.4.5)
Resource:	Limited for oil use; coal use difficult except for large generators
Regionality:	Largest potential in industrialized regions
Environmental:	Emissions
Institutional:	Ability of smaller generators to cope with regulatory requirements
COST AND PERFORMANCE DATA	
Capital Cost ($/kW):	(See note)
O&M Cost (¢/kWh)*:	--
Heat Rate or Efficiency:	5,000-6,500 Btu/kWh
Capacity Factor:	--

Note: Excess electricity sold to utilities at a price based on utilities' avoided cost of generation.

*Operation and Maintenance Cost (cents per kilowatt-hour).

TABLE 4-13

Summary Assessment of Solar Thermal Power

TECHNOLOGY: Solar Thermal Power	
Load Type:	Intermediate/fuel-saver
Fuel:	None in steam system with storage; distillate fuel oil for backup combustor in hybrid gas turbine
Status:	Pilot
DEPLOYMENT SCHEDULE	
First Commercial Service:	1995-1997
Lead Time:	5-7 years
Unit Life:	30 years
PRINCIPAL DEPLOYMENT FACTORS	
Technological:	Substantial heliostat cost reduction required
Resource:	Large; best in Southwest
Regionality:	Initial deployment likely to be concentrated in the Southwest
Environmental:	Handling and disposal of system fluids and wastes leading to water contamination; alteration of microclimate; large quantities of land required; ecological impacts of heliostat fields
Institutional:	May be adversely impacted by changes in the Federal budget
COST AND PERFORMANCE DATA	
Capital Cost ($/kW):	1,700-2,000
O&M Cost (¢/kWh)*:	0.4-0.6
Heat Rate or Efficiency:	--
Capacity Factor:	30-50 percent

*Operation and Maintenance Cost (cents per kilowatt-hour).

TABLE 4-14

Summary Assessment of Wind Power

TECHNOLOGY: Wind Power

Load Type:	Intermediate/fuel-saver
Fuel:	--
Status:	Demonstration

DEPLOYMENT SCHEDULE

First Commercial Service:	1986-1988
Lead Time:	2-3 years
Unit Life:	20-30 years

PRINCIPAL DEPLOYMENT FACTORS

Technological:	Requires cost reduction through mass production and further development
Resource:	Large
Regionality:	Best wind resources in Northeast, Appalachia, Great Plains, and areas of the West Coast
Environmental:	Aesthetics; noise
Institutional:	Siting may be a factor

COST AND PERFORMANCE DATA

Capital Cost ($/kW):	800-1,000
O&M Cost (¢/kWh)*:	1-3 percent per year of initial investment
Heat Rate or Efficiency:	--
Capacity Factor:	20-45 percent

Note: Capital costs are based on a rated wind speed of about 30 mph. Effective capability of large arrays ranges from about 35 percent rated capacity to under 10 percent, depending on design and location.

*Operation and Maintenance Cost (cents per kilowatt-hour).

TABLE 4-15

Summary Assessment of Tidal Power

TECHNOLOGY: Tidal Power

Load Type:	Intermediate/fuel-saver
Fuel:	--
Status:	Available

DEPLOYMENT SCHEDULE

First Commercial Service:	1990 (but operation in United States before 2000 is unlikely)
Lead Time:	6-12 years
Unit Life:	50+ years

PRINCIPAL DEPLOYMENT FACTORS

Technological:	None
Resource:	Limited
Regionality:	Only potential sites in Maine and Alaska
Environmental:	Similar to hydroelectric
Institutional:	--

COST AND PERFORMANCE DATA

Capital Cost ($/kW):	2,300-3,500 (project-specific)
O&M Cost (¢/kWh)*:	0.2
Heat Rate or Efficiency:	--
Capacity Factor:	24-48 percent

*Operation and Maintenance Cost (cents per kilowatt-hour).

TABLE 4-16

Summary Assessment of Wood-Fired Powerplant

TECHNOLOGY: Wood-Fired Powerplant

Load Type:	Base/intermediate (substantial portion likely to be base loaded in study time-frame)
Fuel:	Wood, biomass wastes
Status:	Available

DEPLOYMENT SCHEDULE

First Commercial Service:	Current
Lead Time:	3-5 years
Unit Life:	30 years

PRINCIPAL DEPLOYMENT FACTORS

Technological:	None significant
Resource:	Substantial
Regionality:	Most concentrated potential in northern tier states and Southeast
Environmental:	Emissions; wood harvesting requires large land areas; potential erosion problems.
Institutional:	--

COST AND PERFORMANCE DATA

Capital Cost ($/kW):	1,500 ± 200
O&M Cost (¢/kWh)*:	0.5-1.0
Heat Rate or Efficiency:	14,500 Btu/kWh
Capacity Factor:	65 percent (typical)

*Operation and Maintenance Cost (cents per kilowatt-hour).

TABLE 4-17

Regional Availability of Alternative Supply Technologies*

Technology	Regional Availability	Reference**
Compressed Air	Available in all regions; potentially constrained by geology in portions of the East Coast, Southeast (especially Florida), Great Lakes, Southwest, and West Coast	Section 3.2.3.2 Table 3-2
Hydroelectric	Available in all regions; greatest potential in the Pacific Northwest, with substantial potential in the Northeast, West Virginia, Kentucky, Tennessee, Arkansas, and California	Section 3.2.3.6
Solar Photovoltaic	Available in all regions; best capacity factors in the Southwest	Section 3.2.3.7
Solar Thermal	Technically possible in all regions; due to need for direct insolation, initial deployment will be concentrated in the Southwest	Section 3.2.4.6
Wind	Technically possible in all regions; best wind resources in the Northeast, Appalachia, Great Plains States, and portions of California and Washington	Section 3.2.4.7
Tidal	Potential sites limited to Maine and Alaska	Section 3.2.4.8 Figure 3-4
Wood, Other Biomass	Available in all regions; most concentrated potential in North (West, Central, and East) and South Atlantic regions	Section 3.2.4.9

*Other Categories A and B supply technologies are, or will potentially be, available in all regions.

**See also Appendix B.

TABLE 4-18

Potential Contribution of Categories A and B
Alternative Supply Technologies
(in gigawatts (GW)[a])

Technology	Installed 1980	Net Additions Above 1980 Level (GW) 1985	1990	1995	2000
Utility Thermal Storage[b]	0	0	0	0	0
Compressed Air[c]	0	0	0-1	1-3	2-6
Advanced Batteries[c]	0	0	0	0-2	1-5
Combustion Turbines	(48)	(2)	(3)	(2-3)	(0-3)
First-Generation Fuel Cells	0	0	0-1	1-3	1-7*
Hydroelectric	(65)	(4)	(6-7)	(7-8)	(8-10)
Solar Photovoltaic[d]	0	0	0-1	2-4	6-15
Oil Plant Conversion[e]	--	(8)	(16)	(19)	(22)
Combined-Cycle[f]	(8)	(1)	(2-3)	(3-5)	(3-5)
Coal Gasification/ Combined-Cycle[g]	0	0	0	1-5	10-25*
Fluidized Bed[g]	0	0	0	2-10	20-60*
Cogeneration[e]	5	2-5	3-10	4-15	5-20*
Solar Thermal[h]	0	0	0	0-1	1-2*
Wind	0	0	0-1	1-2	3*-6
Tidal	0	0	0	0	0
Wood, Other Biomass[e]	0	0	1	2	4*

*Derived from: Annual Report to Congress, Volume Three: Projections, DOE/EIA-0173(79)/3, Energy Information Administration, U.S. Department of Energy, Washington, D.C. (1980).

TABLE 4-18 (cont'd)

[a]The estimates in this table are uncertain and should only be used with caution. This is particularly true for new technologies since it has been assumed that commercialization schedules will be met. The estimates are not generally additive since some technologies will be in competition with others.

[b]Not including storage at solar thermal powerplants.

[c]Highly uncertain since the technology is not yet commercialized. The Energy Information Administration has not forecast storage capacity, and a literature review did not yield any other penetration forecasts.

[d]A substantial portion of this would be in decentralized nonutility applications; assumes DOE cost targets are met. Effective capability would be on the order of 35 percent of installed (peak) capacity.

[e]A substantial portion of this is likely to be operated as base loaded.

[f]A portion of this may be repowered to coal gasification/combined-cycle.

[g]Would displace new conventional coal units; likely to be dispatched as base loaded through the study time-frame.

[h]High end of range is from Electric Power Research Institute (EPRI) Report No. EPRI ER-978. Effective capability would range from around 40 percent of installed capacity to 20 percent or less.

4.2 COMPARATIVE ASSESSMENT OF PUMPED STORAGE AND ALTERNATIVES

This section presents a comparison of pumped storage facilities and the Categories A and B supply technology alternatives. For each technology, the potential environmental issues and the constraints imposed by institutional/ regulatory, economic, and physical factors are identified in a matrix. The matrix (Figure 4-1) was developed to compare and contrast the significant issues associated with each technology. The issues are rated to indicate the following:

- The potential environmental impacts associated with each technology
- The potential institutional/regulatory impacts on each technology
- The impact of economic characteristics (of each technology) on peaking applicability
- The physical constraining factors that either limit the availability of sites or limit the use of the technology as a peaking system.

The potential issues were rated for each technology using a relative scale. Those issues unlikely to have impacts are rated as of no concern, while those that have potential large-scale impacts are rated a major concern. Potential limited or indirect impacts are rated as of moderate concern. It should be emphasized that this matrix is intended to show a relative ranking between technologies. Since the characteristics of each technology may be more clearly defined and quantified when site-specific and technology-specific alternatives are developed, the relative rankings will probably change. For instance, pumped storage is likely to have a very significant effect on the water quality of a small, previously free-flowing stream, but it is likely to have a negligible effect on the water quality of an existing, large, well-mixed lake.

The following section compares the natural resources required for pumped storage and for the alternatives. A general understanding of these characteristics assists in developing the comparative assessment. This section is followed by a discussion of the four major issues rated in the matrix.

4.2.1 Natural Resources

When comparing the resources required for pumped storage with those required for alternative technologies, some striking contrasts are revealed. The natural resources that should be considered can be broadly categorized as land, water, air, and other resources. The contrasts are discussed in the following paragraphs.

Pumped storage projects may use an enormous land surface area. Due to the nature of the technology, i.e, two reservoirs, a total land area of from 500 to 10,000 acres may be required for a conventional pumped storage system of 1,000-MWh with the head varying between 300 and 1,000 feet (Public Service Electric & Gas Co., 1976). The area required for the reservoirs decreases as head and/or reservoir depth increases. For underground pumped storage, the surface area needed for reservoirs may be reduced by at least one-half the area required for a conventional facility with the same head.

The other energy storage alternatives--utility thermal storage, compressed air, and advanced batteries--generally need less than 2 percent of the land surface area required for a conventional pumped storage facility of equal capacity. However, the other energy storage alternatives may need less than 10 percent of the land area required for an underground pumped storage facility of equal capacity. Although wood-fired plants require a significant land area for wood farming operations, none of the alternative energy generating facilities of equal capacity, except possibly conventional hydroelectric systems, are likely to need nearly as much land area as conventional pumped storage.

The use of water resources may be categorized as water consumed and water needed during operation. Depending on the technology, these quantities may be very different. Although relatively little water is consumed by pumped storage facilities (i.e., losses due to seepage and evaporation), large quantities of water are required during operation. The alternatives that use water for cooling and/or heating purposes consume some water but do not require quantities comparable to pumped storage needs. Conventional hydroelectric plants are the only alternative that uses significantly more water resources from both categories than does pumped storage.

Air resources are used by some alternatives to assimilate noise or combustion waste emissions. Pumped storage facilities use this resource only in an indirect way--namely, if combustion units produce the base power used for pumping. This may be considered rather insignificant, since the end result is to equalize air pollutant emissions throughout the day rather than concentrate emissions during peak power generation, as is the case for combustion units used for peaking purposes.

Probably the only other natural resources of great concern are oil and natural gas. Pumped storage has a rather limited potential to deplete either and again, it is dependent upon the source of pumping energy. If oil- or natural gas-consuming electrical generating systems are used, a rather moderate consumption may be expected. However, if oil- or natural gas-consuming peaking systems are used instead, the depletion of oil or natural gas is more significant due to the inefficiency of these systems operating as peakers.

4.2.2 Physical Constraints

As indicated in Figure 4-1, major physical constraints such as geologic, topographic, and siting factors limit the availability of pumped storage sites. Conventional pumped storage systems need topographic conditions that provide a suitable potential head between upper and lower reservoirs. Geologic conditions are also important, especially for underground pumped storage systems. Consequently, the siting of reservoirs near load demand centers is not always possible. There may be certain regions of the country where there are no suitable potential sites.

Some alternatives with significant siting constraints require certain geologic and/or topographic conditions. The solar-related (solar photovoltaic and thermal) and wind technologies need minimal cloudy periods or optimal wind conditions. Wood and other biomass systems need favorable conditions for the production of biomass near the plant. Therefore, many of these alternatives are limited to certain regions of the country (see Table 4-17).

The remaining alternatives have moderate or no concerns with respect to the availability of sites. This flexibility allows them to be located relatively close to load demand centers, thus reducing the need for transmission facilities and related impacts.

The other physical constraints listed on Figure 4-1, i.e., turnaround and starting times, operational complexity, maintainability, useful life, and potential for expansion, may limit the use of any particular technology as a peaking system. Pumped storage has some clear advantages as is evident from Figure 4-1. Probably its only disadvantage is that it is not easily expanded, unless provisions for expansion are incorporated into the original design.

ALTERNATIVE	PHYSICAL CONSTRAINTS								ECONOMIC CONSIDERATIONS				ENVIRONMENTAL ISSUES										INSTITUTIONAL/REGULATORY CONSTRAINTS									
	GEOLOGIC	TOPOGRAPHIC	SITING	TURN AROUND AND STARTING TIME	OPERATIONAL COMPLEXITY	MAINTAINABILITY	USEFUL LIFE	POTENTIAL FOR EXPANSION	CAPITAL COSTS	O & M COSTS	FUEL SUPPLY COSTS	EFFICIENCY	LAND USE	TERRESTRIAL ECOLOGY	AESTHETICS	WATER QUALITY	AQUATIC/MARINE ECOLOGY	GEOLOGY AND SOILS	GROUNDWATER	AIR QUALITY	SOUND QUALITY	DEPLETION OF OIL OR NATURAL GAS	NEPA	CLEAN AIR ACT	CLEAN WATER ACT	WATER RESOURCES PLANNING ACT	WILD AND SCENIC RIVERS ACT	FISH AND WILDLIFE COORDINATION ACT	STATE LAWS AND REGULATIONS	SAFETY AND HEALTH REGULATIONS	DEVELOPMENT, OWNERSHIP, FINANCE	COST AND BENEFIT
PUMPED STORAGE	■	■	■	□	□	□	□	■	◩	□	■	◩	■	■	■	■	■	◩	□	□	◩	◩	■	□	■	■	■	■	■	◩	◩	■
CONVENTIONAL HYDROELECTRIC	■	■	■	□	□	□	□	■	◩	□	□	□	■	■	◩	■	■	◩	□	□	◩	□	■	□	■	■	■	■	■	◩	◩	■
COMBUSTION TURBINES	□	□	□	◩	□	□	◩	□	□	□	■	■	□	□	◩	◩	◩	□	□	■	◩	■	■	■	◩	◩	◩	□	◩	◩	□	□
COMBINED CYCLE	□	□	□	◩	◩	□	◩	□	◩	□	■	◩	□	□	◩	◩	◩	□	□	■	◩	■	■	■	◩	◩	◩	□	◩	◩	□	□
OIL PLANT CONVERSION	□	□	□	◩	□	□	◩	◩	◩	◩	◩	□	◩	◩	□	◩	■	◩	□	■	◩	□	■	■	◩	□	□	□	◩	◩	□	□
UTILITY THERMAL STORAGE	■	□	■	◩	□	◩	◩	◩	■	□	□	□	□	□	□	◩	◩	□	◩	□	□	◩	■	□	◩	◩	◩	□	◩	◩	□	□
COMPRESSED AIR	■	□	■	◩	□	□	◩	◩	□	□	◩	□	◩	□	□	□	□	□	◩	◩	■	◩	■	■	□	□	◩	□	◩	◩	□	□
ADVANCED BATTERIES	□	□	□	□	□	◩	■	□	◩	□	□	◩	□	□	□	□	◩	□	◩	◩	□	◩	◩	◩	□	□	◩	□	◩	◩	□	□
PHOSPHORIC ACID FUEL CELLS	□	□	□	◩	□	◩	◩	□	◩	◩	◩	◩	□	□	□	□	□	□	◩	□	◩	■	■	□	□	◩	□	◩	◩	□	□	□
SOLAR PHOTOVOLTAIC	□	□	■	■	□	◩	◩	□	■	◩	□	■	◩	◩	◩	□	□	□	□	□	□	□	◩	□	□	□	◩	□	◩	■	□	□
COAL GAS/COMBINED CYCLE	□	□	□	◩	◩	◩	◩	□	■	■	◩	◩	□	□	□	◩	◩	□	□	◩	◩	□	■	■	◩	◩	◩	□	◩	◩	□	□
FLUIDIZED BED	□	□	□	■	◩	◩	◩	□	◩	■	□	◩	□	□	□	◩	◩	□	□	◩	□	□	■	◩	◩	◩	◩	□	◩	◩	□	□
COGENERATION	□	□	◩	■	◩	□	◩	◩	■	◩	□	□	□	□	□	◩	◩	□	□	◩	◩	◩	◩	■	◩	◩	◩	□	◩	◩	□	□
SOLAR THERMAL	□	□	■	■	□	■	◩	◩	■	◩	□	■	◩	◩	◩	◩	◩	□	□	□	□	□	◩	□	◩	◩	◩	□	◩	◩	□	□
WIND	□	■	■	■	□	■	◩	□	◩	◩	□	◩	□	◩	◩	□	□	□	□	□	■	□	◩	□	□	□	◩	□	◩	◩	□	□
TIDAL	□	■	■	■	◩	□	□	■	■	◩	□	◩	■	□	◩	■	■	◩	□	□	□	□	■	□	■	■	◩	□	◩	◩	□	□
WOOD-FIRED	□	□	■	◩	□	◩	◩	◩	■	■	◩	■	■	◩	□	■	■	◩	□	■	□	□	■	■	◩	◩	◩	□	◩	◩	□	□

LEGEND
- □ NO CONCERN
- ◩ MODERATE CONCERN
- ■ MAJOR CONCERN

FIGURE 4-1
COMPARATIVE ASSESSMENT OF IMPACTS OF PUMPED STORAGE AND ALTERNATIVES

Dames & Moore

4.2.3 Economic Considerations

When comparing pumped storage to its alternatives it must be noted first that pumped storage is not an identical alternative, and the comparison will not be strictly between alternatives. Pumped storage is a form of supply-side energy storage without energy addition. It thus functions as supply-side thermal storage and storage batteries do; it differs from compressed air storage in that energy is added in the latter. It differs from fossil sources of peaking energy in regard to the amount of energy originally generated and the time at which it is generated. It is similar in many respects to demand-side thermal storage, or to the effects of load management, but differs in that the efficiency of pumped storage is likely to be lower and in the time of delivery of the energy. Pumped storage differs from reduction in load by more efficient energy utilization (sometimes called conservation) in that pumped storage provides energy whereas conservation enables the consumer to do without it. Thus simple comparisons in terms of dollars per kilowatt of capacity or dollars per kilowatt-hour of energy may not always tell the whole story needed for the assessment.

Among the factors favoring pumped storage economically is the fact that the technology is well known. There is virtually no risk that the project, when completed, will be unable to operate substantially as designed.

Among the factors unfavorable to pumped storage is the long construction time as compared to alternatives. During this time construction costs and the cost of money may escalate greatly, so that the total project cost exceeds what would have been thought acceptable at its inception. Another disadvantageous factor is that pumped storage operations may occur over large areas accessible to the public, and may therefore be more subject to damage suits, interruptions due to environmental problems (real or claimed), and other problems less likely to occur if all operations were conducted within areas wholly under utility control. (Our concern in this section is only to note that these matters have possible economic results.)

When comparing operating costs* of pumped storage with those of alternatives, it must be remembered that although the operating cost of the pumped

*Note: In this section the term "operating cost" is used to signify the sum of the costs of fuel, operation, and maintenance.

storage plant is very low, the operating cost of the plant providing the energy for pumping will probably not be low. Moreover, since the round-trip efficiency of pumped storage is about 72 percent, the source of pumping energy must generate about 139 percent (the reciprocal of 72 percent) of the energy finally delivered. If pumped storage is to be economically more attractive than an alternative peaking plant, then the carrying charges on the pumped storage plant must not exceed those on the alternative by more than the operating costs of the alternative exceed 139 percent of the operating costs of the pumping energy source; or:

Carrying charge for pumped storage plant

\+ 139 percent of operating cost of pumping energy source

\- Carrying charge for alternative peaking plant

\+ Operating cost for alternative peaking plant

But this scheme implicitly assumes that a base-load plant to provide the pumping energy is already in place and paid for. If it is necessary to provide new or additional base-load capacity to provide energy to operate the pumped storage, then the carrying charge for this new or additional capacity must be added to that for the pumped storage plant.

The capital costs of pumped storage plants are, as noted elsewhere in this report, highly dependent on the individual site. It seems reasonable to assume that only sites at which costs are competitive will be considered. There appear to be a sufficient number of these to meet all needs (see Section 4.3.2). As will be noted again in Sections 4.3.1 and 5.5, the construction of new generating plants of any type is proceeding very slowly at the time of this writing (mid-1981) because of the high interest rates utilities must pay on bonds and the low prices (relative to book value) at which they can sell stock. In this respect, pumped storage is now experiencing the same problems as other technologies. However, the relative attractiveness of alternatives will vary as financing costs vary. When financing costs are high, alternatives with low capital but possibly higher operating costs will be preferred. When financing costs are low, alternatives with high capital and low operating costs will be chosen.

To conclude this section we repeat the cost estimates given in Sections 3.3 and 4.1 in a different format in Table 4-19.

TABLE 4-19

Comparison of Cost Data

Technology	Capital cost ($/kW)	Operation and Maintenance Cost (¢/kWh)
Utility Thermal Storage	85-200	N/A
Compressed Air Storage	270-480	0.2
Advanced Storage Batteries	400-700	0.15-0.25
Combustion Turbines	215-250	0.3
First-Generation Fuel Cells	400-700	0.4-0.5
Hydroelectric	500-2,000	--
Solar Photovoltaic	1,100-1,800	0.1-0.3
Combined-Cycle	380-470	0.2-0.3
Coal Gasification/ Combined-Cycle	825-975	0.5
Atmospheric Fluidized Bed	700-900	0.8
Solar Thermal Power	1,700-2,000	0.4-0.6
Wind Power	800-1,000	0.1-0.3
Tidal Power	2,300-3,500	0.2
Wood-Fired Powerplant	1,300-1,700	.5-1.0
Customer Thermal Storage	75-150	N/A
Load Management	100-250	0.1
Pumped Storage	500-2,000	--

4.2.4 Environmental Issues

A quick review of Figure 4-1 reveals that pumped storage has a potential moderate to major environmental impact in most areas of concern. However, no significant air quality and groundwater impacts are likely. A conventional hydroelectric system is the only alternative with potential for widespread impacts of similar magnitude, and there are two reasons for this phenomenon—namely, the large-scale use of land and water resources.

As previously mentioned, pumped storage systems characteristically use relatively large land areas in comparison with all other alternatives except, perhaps, conventional hydroelectric systems or wood-fired plants. Consequently, the potential impact on land use, terrestrial ecology, and aesthetics is great. Obviously, the potential magnitude will be a function of existing conditions; for example, the use of an existing reservoir or lake as part of the pumped storage system is likely to lessen these impacts to some degree.

The large-scale use of water resources is another characteristic common to both conventional hydroelectric and pumped storage systems. Thus, water quality and aquatic ecology impacts are potentially significant. Again, existing conditions will dictate the magnitude of these impacts. A site with a large, well-mixed lake, such as the Ludington pumped storage powerplant where Lake Michigan serves as the lower reservoir, can significantly lessen impacts on water quality and aquatic ecology (Liston, 1977).

Underground pumped storage systems have the potential to have significantly fewer environmental impacts than those associated with conventional pumped storage. Land and water resource use is characteristically less; consequently, the magnitude of land use changes, aesthetic alteration, habitat modification, and water quality change is proportionately reduced.

Pumped storage systems may produce significant beneficial or desirable environmental effects when compared to the alternatives. These could include:

- Supplying energy without air pollution, especially if pumping energy is supplied by a nonemitting base power source such as a nuclear plant
- Reducing the rate of consumption of natural gas and oil resources, especially if pumping energy is supplied by a base power source such as a coal-fired plant

- Providing a means to control both floods and draughts
- Increasing fishery resources
- Providing additional recreation and park facilities.

The most significant differences between environmental impacts associated with the alternatives and those associated with pumped storage are the potential air quality impacts resulting from the combustion of fossil fuels. Sulfur emissions from these systems have the potential to produce acid rain, resulting in secondary impacts on water quality and aquatic ecosystems. The acid rain phenomenon is especially significant for conventional coal combustion units, since they have the potential to produce sulfur emissions 2 or 3 times greater than those produced by oil- or natural gas-fired plants. Thus the oil plant conversion alternative has a potentially significant aquatic ecology impact.

Wood-burning plants also have potentially significant air quality impacts. In addition, erosion, resulting from large-scale wood-farming operations, has a potential significant water quality/aquatic ecology impact. Also, large land areas are required; thus the potential land use impact may be significant.

As indicated in Figure 4-1, the remaining alternatives have mainly moderate or no potential environmental impact. Moderate air quality or water quality/ aquatic ecology impacts were assigned to alternatives with potentially limited air pollutant emissions or thermal water pollution discharges, respectively. Alternatives requiring significant land area were assigned moderate to major ratings for potential land use, terrestrial ecology, and aesthetic impacts. Potential major sound quality impacts were associated with the compressed air and wind alternatives only.

The potential human impacts, such as those on historical and archaeological sites, were not included in the matrix. Although any alternative may have a significant impact, these types of impacts are generally site specific.

4.2.5 Institutional/Regulatory Issues

The regulatory issues listed in Figure 4-1 may be characterized as environmental and/or operational regulations. The environmental regulations probably have the most significant impact on siting powerplants whereas the operational regulations affect day-to-day operating procedures and costs.

The major environmental laws and regulations include: National Environmental Policy Act of 1969 (NEPA); Clean Air Act of 1970, 1977 (CAA); Clean Water Act of 1972, 1977 (CWA); Water Resources Planning Act; Wild and Scenic Rivers Act of 1968; Fish and Wildlife Coordination Act of 1958; and some state laws and regulations. These laws and regulations might affect the siting of a powerplant. The CAA, CWA, and some state laws and regulations may also affect powerplant operations through a permitting program. These and some additional site-specific Federal environmental laws and regulatory guides affecting siting of powerplants are listed in Table 4-20.

As is evident from Figure 4-1, the technologies with potentially significant environmental impacts are similarly affected by the environmental regulations designed to protect environmental resources. Since pumped storage and conventional hydroelectric systems can have large-scale environmental impacts (as discussed previously), they are potentially affected to a similar degree by corequisite environmental regulations. Thus the major difference between pumped storage systems and the alternatives is the negligible impact of air quality regulations and the significant impacts of water and land resources related regulations.

The significance of impacts resulting from environmental laws and regulations is probably best understood by comparing two similar projects, one developed prior to 1970, and the other after 1970 when several environmental laws and regulations had been established (see Table 4-19). The Blenheim-Gilboa and Breakabeen-Prattsville projects are examples. As previously discussed in Chapter 2, the projects were located in the same watershed. The Blenheim-Gilboa project, initiated prior to 1970, consisted of the construction of two reservoirs and an aboveground powerhouse; it required 10 months to obtain license approval and start construction. In contrast, it has been 7-1/2 years since license applications were submitted for Breakabeen, and approval is still uncertain. Estimated construction costs have increased from $397,800,000 to $497,588,000. The delay has occurred for environmental reasons even though the Prattsville project uses an existing reservoir, has an underground powerhouse, and is in a less sensitive area with regard to historic and archeological impacts. A comprehensive site selection study and public participation program, such as the approach taken by PG&E during project planning for the Helms facility, can significantly reduce this impact.

Plant safety and health regulations are potential moderate impacts for nearly all technologies. Major impacts are possible for the solar photovoltaic technology,

TABLE 4-20

Environmental Laws and Regulatory Guides Affecting Siting of Powerplants

Federal Laws, Executive Orders, Regulatory Guides	General	Air	Water	Land/Oceans Use	Species & Habitats	Cultural Resources
Anadromous Fish Conservation Act of 1965					X	
Archaeological & Historical Preservation Act of 1974						X
Archaeological Resources Protection Act of 1979						X
Clean Air Act of 1970, 1977		X				
Clean Water Act of 1972, 1977			X			
Coastal Zone Management Act of 1972, 1976				X		
Endangered Species Act of 1973, 1979					X	
Federal Land Policy & Management Act of 1976				X		
Fish & Wildlife Coordination Act of 1958					X	
Floodplain Management (Executive Order 11988) of 1977				X		
Marine Mammal Protection Act of 1972					X	
Marine Protection, Research & Sanctuaries Act of 1972				X	X	
Migratory Bird Conservation Act of 1929					X	
Multiple-Use & Sustained Yield Act of 1960				X		
National Environmental Policy Act of 1969	X					
National Forest Management Act of 1976				X		
National Historic Preservation Act of 1966						X
National Trails System Act of 1968				X		
Protection of Wetlands (Executive Order 11990) of 1977				X	X	
Rivers and Harbors Act of 1899			X	X		
Water Bank Act of 1970				X	X	
Wild & Scenic Rivers Act of 1968				X		
Wilderness Act of 1964				X		

Source: Modified from Dames & Moore et. al., 1980.

since exposure to toxic substances during the manufacturing of photovoltaic cells is a major concern.

Institutional impacts on pumped storage and conventional hydroelectric systems are rather unique when compared to the alternatives. The potential impact results from a variety of possible development, ownership, and financing schemes which may involve several utilities, state government, and Federal government organizations such as the Bureau of Reclamation (formerly the Bureau of Land Management) and Corps of Engineers. In addition, a cost and benefit analysis is required if the project is Federally financed.

Current regulations resulting from the Powerplant and Industrial Fuel Use Act of 1978 were not included in this discussion since they are presently under review and are likely to be significantly modified, if not abolished.

4.3 FACTORS AFFECTING FUTURE DEVELOPMENT OF PUMPED STORAGE

The future development of pumped storage will be affected by the competing technologies discussed in the previous sections. In addition to this competition, there are economic, physical, and environmental factors associated with pumped storage that are likely to significantly affect future development. These major factors are highlighted in the following sections.

4.3.1 Economic

The cost of operating a peaking plant for a year can be well approximated by the following relation:

$$\begin{aligned}\text{Annual Cost} &= (\text{Capital Cost}) \times (\text{Annual Carrying Charge Rate}) \\ &+ ((\text{Rated MW}) \times (\text{Capacity Factor}) + \text{Losses}) \\ &\times (\text{Fuel Cost, \$/MWh} + \text{O\&M Cost, \$/MWh}) \times 8{,}760 \text{ hours}\end{aligned}$$

This shows that the important economic parameters are:

Original cost	
Financing costs	(Carrying Charges)
Output energy	(Rating x Capacity Factor)
Fuel cost	
Efficiency	(Losses)

All of these are important factors affecting the development of pumped storage. (The operating and maintenance costs are usually not large contributors.) How costs for pumped storage compare with costs for alternatives will determine the future development of pumped storage.

The original capital cost or investment in a pumped storage plant will depend on its site, and only sites that have competitive costs will be considered (Section 4.2.3). Surveys of suitable sites (Section 4.3.2) suggest that an ample number of such sites exist. Whether pumped storage remains competitive depends on how costs of pumped storage plants (now largely land and construction costs) vary in relation to costs of alternative capacity, especially energy storage systems (largely mechanical and electric equipment).

Although the cost of money affects all types of generating plants, its effect is greatest on plants with the highest capital cost per unit capacity. At present the high cost of financing capital has brought new plant construction to its lowest level for several years. However, if financing costs come down, those technologies with the highest unit capital costs will benefit most. Thus with reference to Table 4-19, it would seem that utility thermal storage, consumer thermal storage, and compressed air storage (if developed successfully) would stand to benefit more than the average pumped storage site if finance charges fall.

The maximum feasible capacity factor for a pumped storage plant using the same rotor for pumping and generating is of the order of 30 to 35 percent. This far exceeds the 17 percent allowed for oil-burning peaking plants, or the 15 percent estimated in Tables 4-2 and 4-3 for alternative energy storage. On the other hand, it is not as good as alternative coal or wood-fired plants, and only about the same as some solar and wind plants in good locations. The output energy of the pumped storage plant could be increased, assuming that pumping power is available, by supplying a bigger pumping than generating unit. The capacity factor would not seem to be a limiting factor in pumped storage development.

A major determinant of pumped storage development, however, is demand growth. In Section 5.0 we show the supportable pumped storage demand under three growth scenarios with and without load management. The range of values at the end of this century is 149,969 to 17,161 MW or more than 8 to 1 (Table 5-5).

Probably the most significant determinant of the future development of electric energy storage systems in the United States will be fuel cost. Energy storage systems--and especially pumped storage--are widely regarded as the natural concomitants to base-load coal-fired or nuclear plants as a means of reducing the national dependence on imported oils or even scarce domestic oil. So long as the cost per unit of energy from coal or nuclear fuel is much below that of oil (as it is of this writing in mid-1981), construction of pumped storage is encouraged. Indeed, in New England the cost differential between Fuel Oil #6 and the grades used in oil-fired peaker plants has been enough to justify operating oil-fired steam plants to furnish pumping energy for pumped storage. Should discovery of large reserves of oil bring its price down to that of coal or nuclear generation, the attractiveness of any energy storage scheme, including pumped storage, would lessen or disappear. This is especially so since all storage systems involve an energy loss in operation, and this loss must be supplied by burning more of whatever fuel is being used.

The round-trip efficiency (defined as the product of pumping efficiency and generating efficiency) of a pumped storage system is now typically 70 percent or so. Although research and development may improve this somewhat, a sizeable improvement of, say, 50 percent is obviously impossible. Similarly, other energy storage technologies are about equally efficient. On the other hand, the present low efficiencies of solar, wind, and wood-fired plants seem to offer opportunities for improvement. This would seem in the long run to diminish somewhat the potential for pumped storage development.

4.3.2 Physical

The major physical factors affecting the future development of pumped storage systems relate to siting constraints and operating characteristics. The operating characteristics are probably the most significant factors that encourage pumped storage development, whereas siting constraints may limit the available sites within an area or region.

Pumped storage systems are easy to operate and have relatively quick turnaround and starting times. These characteristics make pumped storage extremely reliable, and consequently pumped storage systems are an attractive method of providing spinning reserve capacity for emergency responses in addition to peak power. This in fact was part of the rationale for development of the Blenheim-Gilboa plant (see Chapter 2) and most other pumped storage systems.

The most significant siting constraints relate to topographic and geologic conditions. Conventional pumped storage systems preferably require a head greater than 700 feet due to the cost versus head relationship. Topographic conditions also determine reservoir shape and area, dike length, and water conduit length between reservoirs. Excavation for additional components of pumped storage systems are affected by topography. Geologic factors will determine reservoir bottom sealing needs to reduce seepage losses and will affect tunneling costs. All these factors may have a critical impact on project cost.

Underground pumped storage systems are significantly affected by geologic and groundwater conditions although topography is not as significant. A sound stratum of several hundred or possibly thousands of feet below the ground surface is required and must be favorable for removal by mining techniques. Obviously groundwater conditions must be such that the lower reservoir will not refill significantly during pumping operations.

It appears that there are very few regions or areas where siting constraints may significantly affect the future development of pumped storage systems. Studies of potential pumped storage sites have been done to determine the capacity available from conventional systems. Tables 4-21 and 4-22 summarize these data by region (see Figure 4-2); Figure 4-3 indicates areas of the United States where geologic conditions are especially favorable for underground pumped storage. Pumped storage operational characteristics also should encourage future development.

More detailed economic and environmental analyses of the potential sites, however, probably will reduce the potential conventional capacity available. For example, the Potomac Electric Power Company (PEPCO) studied available pumped storage sites in an area 80 to 120 miles west and northwest of Washington, D.C. After screening an initial list of 100 potential sites, 19 sites were chosen for a field survey. Ten sites, each with a potential capacity in excess of 2,000 MW, were considered acceptable based on the field survey, which was conducted to assess costs, construction problems, transmission routes, and environmental impacts. However, since the sites were not close to the PEPCO service area, long transmission lines were required. Construction of the transmission lines would have undesirable environmental impacts; therefore, these sites were dropped from consideration, and the company began an investigation of nearby areas suitable for underground pumped storage.

TABLE 4-21

Estimated Availability of Pumped Storage Sites

Region	Availability of Pumped Storage Sites (MW)
New England	> 9,250
Middle Atlantic	19,830 - 26,440
East North Central	17,340 - 26,010
West North Central	6,920 - 10,380
South Atlantic	25,890 - 34,520
East South Central	16,840 - 21,050
West South Central	5,970 - 11,940
Mountain	>12,350
Pacific	>27,000
Alaska and Hawaii	360 - 540

Source: Modified from Public Service Electric and Gas Company, 1976.

TABLE 4-22

Estimated Capacity of Pumped Storage Systems

Region	Operating (MW)	Projected (MW)	Federal or Licensing Status (MW)	Identified Potential (MW)
1	4,430	2,000	1,400	49,400[a]
2	--	--	--	--
3	3,186	3,775	--	1,405[d]
4	2,622	1,216	3,000	8,589[d]
5	299	--	730	--
6	623	200	5,020	650,000[b]
7	1,612	2,155	--	341,100[c]

Note: Not all regions have been studied for potential sites. Region 2 is probably the only region where there are no potential sites.

Sources: [a]Public Service Electric and Gas Company, 1976.

[b]U.S. Army Corps of Engineers, 1972.

[c]Federal Power Commission, 1975.

[d]U.S. Army Corps of Engineers, personal communication.

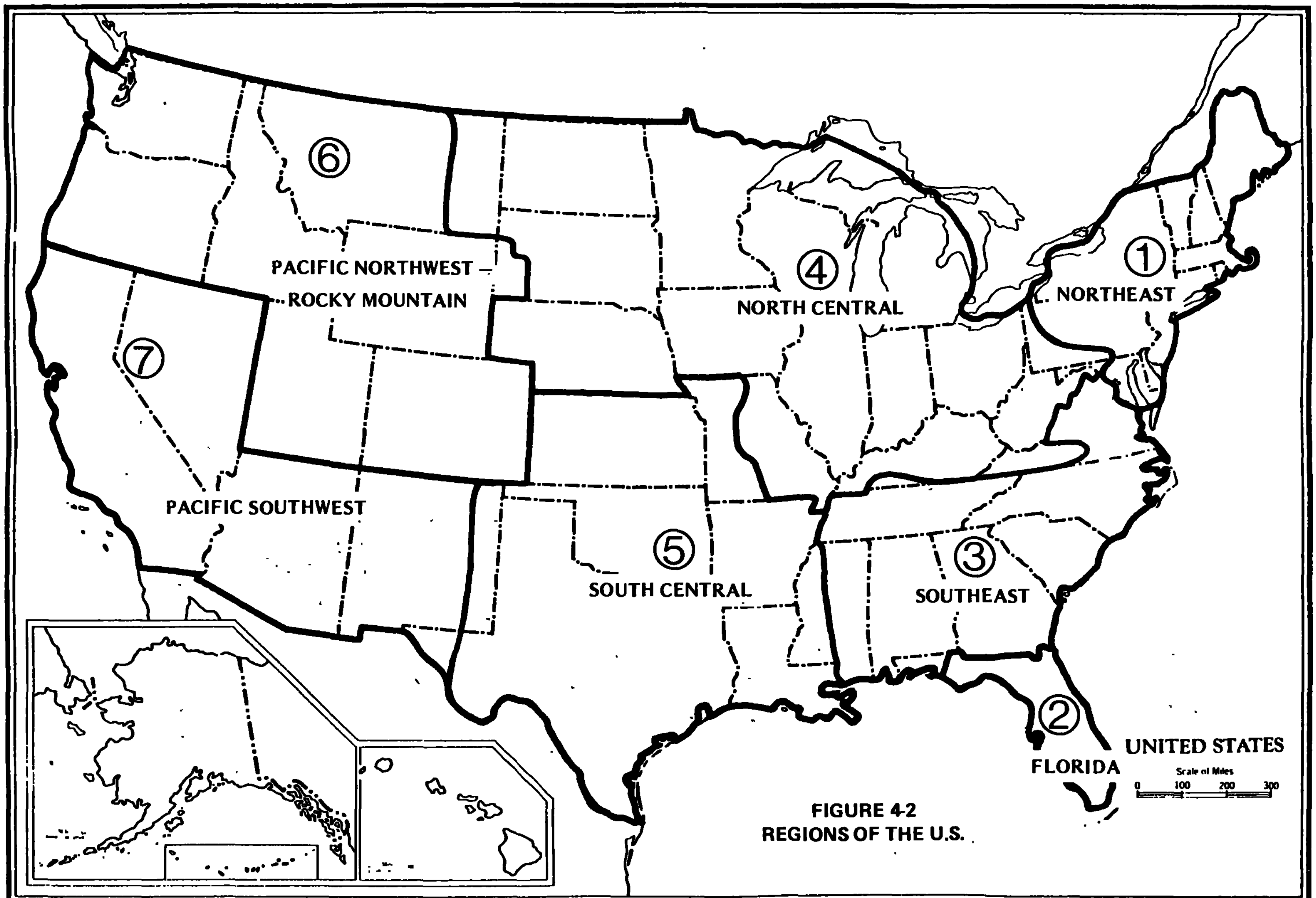
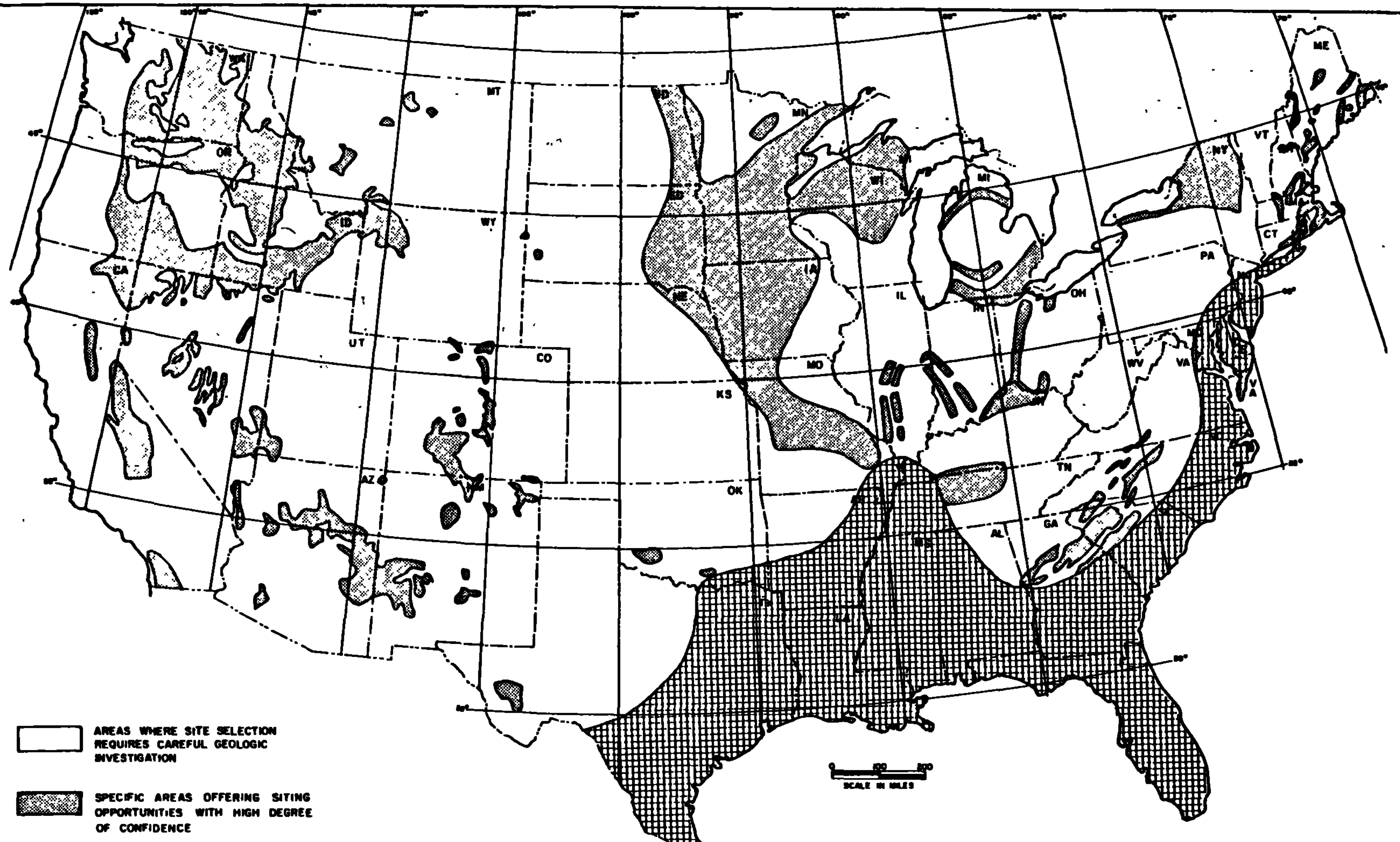


FIGURE 4-2
REGIONS OF THE U.S.



AREAS WHERE SITE SELECTION REQUIRES CAREFUL GEOLOGIC INVESTIGATION

SPECIFIC AREAS OFFERING SITING OPPORTUNITIES WITH HIGH DEGREE OF CONFIDENCE

SUITABLE ROCK TOO DEEP OR DEPTH OF UNSUITABLE MATERIAL TOO GREAT

FIGURE 4-3
GEOLOGIC SITING OPPORTUNITIES - UHPS

SOURCE Charles T Main, Inc., 1978.
(FROM ACRES AMERICAN STUDY 3 AND PUBLIC SERVICE ELECTRIC AND GAS STUDY 2, TABLE II-1)

4.3.3 Environment

The major environmental factors affecting the future development of pumped storage systems relate to the natural resources that may or may not be altered during construction and operation. As is the case for most energy producing technologies, pumped storage has both environmental advantages and disadvantages. The importance of these factors must be judged in relationship to the specific needs and alternatives available to meet those needs.

The negligible air quality impacts of pumped storage can be a significant asset in regions in which the degradation of air is an issue. Similarly, areas requiring flood control or storage reservoirs for water supply may be amenable to pumped storage systems. Provisions to increase fishery resources and additional recreation and park facilities can also become an environmental asset. The Blenheim-Gilboa plant in New York is a good example (see Chapter 2). The project established a fish population in the reservoirs, and recreational facilities such as a visitors' center, swimming pools, boathouses, boat launching camps, and picnic areas. An historic farm complex was preserved and restored and has become a major information, education, and scientific center.

Major negative environmental factors affecting the future development of pumped storage systems relate to land use changes and changes in the hydraulic and hydrologic conditions of water resources. Potential impacts on land use, aesthetics, terrestrial habitats, water quality, and aquatic ecosystems may preclude development. Environmentally sensitive areas are often site specific, but some general characteristics are easily identified.

The environmentally sensitive areas are the same areas commonly excluded from conventional hydroelectric development. These include: national or state parks; designated wild or scenic river reaches; wilderness or primitive areas; areas that provide habitats for endangered species; and areas containing sites of archeologic or historic significance. In two studies that identified potential pumped storage sites, the site selection process excluded sites based on the first three criteria (Federal Power Commission, 1974; U.S. Army Corps of Engineers, 1976).

The Prattsville project in New York (see Chapter 2) provides an example of an environmentally sensitive area. It has been estimated that operation of the project would alter the downstream temperature regime. Destratification of the lower reservoir during summer operations would increase temperatures downstream, possibly damaging trout habitat. Consequently, due to environmental opposition, construction of the project is uncertain.

Potential pumped storage sites that minimize environmental impacts may include the use of sites with existing reservoirs or large lakes. Since the land area required for the development can be greatly reduced, the land use changes can be minimized. Consequently, aesthetic impacts and the reduction in terrestrial habitats may also be reduced. Where a large, existing, well-mixed lake or reservoir is used, water quality changes with resultant impacts on aquatic life may be diminished.

The Helms project stands out among the other pumped storage projects (see Chapter 2). It was constructed in an environmentally sensitive area--namely, within the Sierra National Forest and about one mile from the Jon Muir Wilderness Area. However, environmental impacts were significantly reduced since two existing reservoirs were utilized.

The development of underground pumped storage systems may have a similar effect in reducing environmental impacts. Additionally, since these systems are not dependent upon topographic conditions to provide an adequate potential head, they may be located closer to the load demand center, reducing the need for transmission systems and their resultant environmental impacts. The major negative environmental factors are a result of the disposal of large quantities of excavated rock material, mineralization of water, transfer of lower rock body heat to the upper reservoir during pumping, and potential eutrophication in reservoirs. Groundwater and geologic conditions will be a major siting factor, and as is the case for Florida, may exclude certain areas or regions of the country from consideration.

The future development of pumped storage will probably be significantly affected as a result of the environmental factors. Planning efforts are frequently protracted, and actual construction may be uncertain during this time-frame. It appears that the natural tendency of the utilities is to move toward less capital-intensive alternatives that require less arduous planning efforts.

REFERENCES

Charles T. Main, Inc., Underground Hydroelectric Pumped Storage, An Elevation, the Concept, Department of Interior and Department of Energy, Washington, D.C., November 1978.

Clugston, James P., and Prince, Eric D., "Impacts of Pumped Storage Hydroelectric Operations on Southeastern Reservoirs," Ludington Workshop on Environmental Effects of Pumped Storage Power Facilities, Ludington, Michigan, August 1977.

Dames & Moore and Rogers, Golder & Halpern, Alternative Siting Requirements and Practices for Nuclear Power Plants, prepared for Atomic Industrial Forum, Washington, D.C., June 1980.

Federal Power Commission, Bureau of Power, Potential Pumped Storage Projects in the Pacific Southwest, Washington, D.C., 1975.

Final Environmental Impact Statement, Prattsville, New York, July 1979.

Karadi, Gabor M., Mosonyi, Emil F., and Rohde, Fritz, Final Report to National Science Foundation, Pumped Storage Development and its Environmental Effects, Milwaukee, Wisconsin, 1974.

Lambert, Thomas R., "The Helms Pumped Storage Project--Environmental Concerns," Ludington Workshop on Environmental Effects of Pumped Storage Power Facilities, Ludington, Michigan, August 1977.

Lewis, Joe, U.S. Corps of Engineers, Wilmington, North Carolina, District, personal communication, April 1981.

Liston, Charles R., Tack, Peter I., and Brazo, Dan C., "Overview of Research on Impacts of the Ludington Pumped Storage Power Plant," Ludington Workshop on Environmental Effects of Pumped Storage Power Facilities, Ludington, Michigan, August 1977.

Miracle, R.D., and Gardner, J.A., Jr., "Review of the Literature on the Effects of Pumped Storage Operations on Ichthyofauna," Proceedings, Clemson Workshop on Environmental Impacts of Pumped Storage Hydroelectric Operations, Clemson, South Carolina, 1979.

Public Service Electric and Gas Company, An Assessment of Energy Storage Systems Suitable for Use by Electric Utilities, Energy Research and Development Administration, Washington, D.C., July 1976.

Roza, Ralph, U.S. Corps of Engineers, Missouri River Division, personal communication, April 1981.

The Mitre Corporation, Short-Forum Environmental Development Plans: An Analysis and Summary, prepared for the Energy Research and Development Administration, February 1977.

U.S. Army Corps of Engineers, Pumped-Storage in the Pacific Northwest, An Inventory, Portland, Oregon, January 1976.

U.S. Department of Energy, Technology Characterization-Environmental Information Handbook, Washington, D.C., January 1980.

5.0 ESTIMATE OF FUTURE DEMAND FOR PUMPED STORAGE AND ITS ALTERNATIVES

5.1 INTRODUCTION

Up to this point, the thrust of this report has been to define the characteristics of pumped storage and its alternatives, and no estimates on the extent to which new capacity would be needed to meet future peak demand have been presented. The purpose of the following discussion, therefore, is to quantify, in megawatts, the regional demand for pumped storage or its alternatives between now and the end of the century. To do this, a special-purpose computer program using regional data on the installed and planned electric generating systems in the United States has been developed. The program is used to estimate, for the various assumed growth rates, the amount of additional pumped storage or its alternatives that will be needed over the next 20 years.

Specifically, estimates are developed for the maximum pumped storage capacity that could be required, as well as for the estimated supportable pumped storage energy and unsited base capacity needed in conjunction with pumped storage. For the purposes of this analysis, maximum pumped storage capacity is defined to mean the maximum amount of megawatt capacity that would be obtained from the use of these pumped storage facilities. In this context, maximum is taken to mean enough additional pumped storage capacity to meet any future requirement for stored energy. Similarly, the estimated supportable pumped storage energy simply means the number of gigawatt-hours produced by this estimated additional pumped storage generation. In like manner, estimates of unsited base capacity represent the additional base capacity needed to support the estimated demand for electricity, which at this point could be termed unplanned generation expansion projects. This estimate includes not only unsited base capacity required to support pumped storage development, but all yet unsited base capacity required to meet total system load projections. Similar estimates are developed for such needed additional capacity as would be available from new technologies other than pumped storage.

In the analysis reported in the previous chapters of this report, it was shown that a combination of technological, geographical, environmental, and institutional factors govern the future availability of peaking generation capacity. As will be obvious from the analysis reported in this section, for even the minimum future peaking capacity requirements forecast herein, sufficient capacity to meet projected demands will be available only when substantial further additions of conventional pumped storage, gas- or oil-fired turbines or other peak storage technologies are developed.

Over the long run, the degree to which additional pumped storage capacity (or its technological alternatives) is added to the nation's electrical generating systems will be the result of a complex set of interactions between a number of constantly changing economic, demographic, and physical factors. Today, the most important of these factors are economic--in particular, the current troubled condition of the national economy. Nationwide, demand for new generating capacity has been strongly impacted by inflation and high interest rates. In addition, regional generation fuel mixes (with origins in earlier economic and environmental action); the future availability and cost of fuel; and the local rate of population growth and business activity have influenced the demand and type of new generating capacity developed. Each of these factors will be examined later in this chapter.

To determine the impact of these factors, an economic "stacking dispatch" methodology was developed to forecast the need for future base-load and peaking capacity additions, including pumped storage. In this method, a series of regional demand forecasts are assumed. These forecasts range from a low average annual compound growth rate of 2.6 percent to a high average annual compound growth rate of 4.4 percent for the continental United States. Demand growth rates are projected on a regional basis for both base-load and peaking energy. The computer program compares these demands, on a year-by-year basis, with the availability of existing capacity and with previously announced forecasted (or planned) capacity additions. If the announced or planned capacity expansion plans are inadequate to meet the assumed demand, the computer program computes the needed base-load and peaking capacity additions necessary to maintain area reliability. As will be explained in more detail, however, although the load growth assumptions for the computations are identical, the fuel generation additions that result differ according to whether pumped storage or an alternative technology is used to provide peaking power.

Various scenarios, consisting of different run conditions, were used to determine the future development of pumped storage capacity and alternative capacity technologies. The scenarios are listed in Table 5-1. Briefly, the potential

TABLE 5-1

Scenarios

Pumped storage capacity and alternative capacity technologies were forecast under each of the three demand projections (Projection II, Median, and Dames & Moore) for each of the supply conditions below.

I. Base-Load Shape

   A. Utility-Announced Retirements Schedule
      1. After coal steam
      2. After oil steam
      3. After all other fuel types

   B. Generic Retirement Schedule
      1. After coal steam
      2. After oil steam
      3. After all other fuel types

II. Load Management Techniques

   A. Utility-Announced Retirement Schedule
      1. After coal steam
      2. After oil steam
      3. After all other fuel types

   B. Generic Retirement Schedule
      1. After coal steam
      2. After oil steam
      3. After all other fuel types

for pumped storage capacity development was assessed under the three load growth forecasts described above. Existing plant capacity was retired under two separate schedules--utility announced retirements, as reported by the National Electric Reliability Council (NERC), and generic retirements based strictly on the age of a generation unit. Sources of generating electricity were ordered with the most economical source dispatched to generate electricity first and the least economical source of generation last. Pumped storage was dispatched under three scenarios of dispatch order--after oil steam, after coal steam, and last. For instance, pumped storage dispatched after oil steam assumes pumped storage is less economical in generating electricity than oil steam but more economical than gas combined cycle generation. (Table C-1 in Appendix C shows the initial dispatching order used in the analysis). The impact of the economic ordering of pumped storage was assessed under each scenario. The effects of load management on future pumped storage capacity development were also examined. Each run condition and its results are described in detail in this chapter. As will be seen from a careful examination of the results, the level of assumed future demand growth, the assumed source of power to drive pumped storage, and the fuels that pumped storage will displace when dispatched to meet demand loads are all crucial determinants of future pumped storage capacity development.

These elements have not been selected capriciously. Their choice has its roots in the current ability of the industry to built future capacity; this choice process has been modelled and given an analytical and predictive basis. To illustrate this basis, a financial analysis has been developed in which the present and future costs to the consumer are calculated for a variety of pumped storage and peaking mixes. As will be seen from the results, the future mixes that are likely to be used will be determined by existing regional generation mixes and the relative costs and availability of fuels for conventional base-load and peaking generation technologies. It will be seen that existing regional generation mixes are partly the result of recent changes in regional growth rates. In many parts of the country, as fuel prices have risen (particularly in oil- and gas-burning regions), predicted loads have failed to develop, and the generation systems were left with excess capacity already in the construction pipeline.

Therefore, as a first step toward understanding the impact of the need for new pumped storage, a detailed historical analysis of regional electricity demand will be developed in conjunction with a description of the three load growth forecasts used in the analysis (Section 5.2). Thereafter, the analysis of pumped storage is presented for each region and scenario (Section 5.3); the implications of and reasoning behind the regional results are closely examined and discussed; and finally, a description of the regional computer program is provided (Section 5.4). These sections are followed by a financial analysis of the cost calculations that support the choice basis used in the computer program (Section 5.5).

5.2 REGIONAL ELECTRICITY DEMAND

5.2.1 Determinants of Demand

Three basic factors affect the demand for electricity: the price charged for it, the Nation's level of economic activity (the gross national product), and the number and types of customers that use electricity. Over the long run, charges for electricity are simply the result of the cost of production factors, the cost of the system used to generate it, and the cost of the management skill needed to operate the enterprise. Since the electric utility industry is a regulated monopoly, profitability does not play a major role in determining the current cost of electricity but acts instead to attract future investment to the firms. The price of electricity, therefore, is primarily the result of the cost of capital and fuel.

Regions of the country where utilities generate electricity from expensive fuels such as oil and gas have seen electricity demand falter because of large price increases. New England is an example of such a region. Growth in the demand for electricity in New England has fallen sharply since the 1973 OPEC oil embargo and shows no signs of returning to the level of growth experienced before that period anytime in the next decade. And even regions that have had an abundance of electricity are facing drastic changes in demand. The Pacific Northwest and Rocky Mountain regions are both heavily hydro based. Since hydroelectric generation is one of the least expensive means of producing electricity, demand growth rates in these regions characteristically have been high and electricity has been inexpensive. Today, however, the Pacific Northwest and Rocky Mountain regions are experiencing difficulty in obtaining permission to build new generating facilities, and the price of electricity has risen to a rate more reflective of prices in the rest of the country. Should these two factors continue, growth in the rate of demand will be constrained.

With respect to the second factor (level of economic activity) that affects electricity demand, the size of the population to be served and the kinds of manufacturing and service industries that provide employment to that population must be taken into account. Since manufacturing and service industries vary greatly in their use of electricity, heavily industrial regions will require more electricity than more rural areas. This fact is particularly relevant in capital-intensive industries (such as those in the Central Industrial region) as opposed to the more labor-intensive industries of the Southeast. Since the price of electricity and these demographic factors will interact for every region of the country, in the long run, if the price of electricity changes radically, both its per capita use and the industrial attractiveness of any particular region could be affected.

The number and types of customers that use electricity--the third factor--also influence the demand for electricity, and in any industrialized region of the country that demand will be closely linked with business cycles. In an economic environment that is stable over the long run, the ups and downs of these cycles balance out to an underlying growth rate, and for most analytical purposes it is this underlying rate that is important. However, during the last two decades, several of the more dramatic economic events have been those business cycles that were closely intertwined with sharp price increases in OPEC oil. These cycles have become guideposts to future demand growth rates because they so graphically illustrate the changes in the before and after electricity use rates. Indeed, an examination of regional demand during this time supports this proposition. The structural use of electricity changed because oil price increases affected both the overall economy and the cost of generating electricity from oil burners. The growth rates resulting from these business cycles, then, are watershed events in the forecasting of regional demand for electricity. The Central Industrial and Middle Atlantic regions, both prime contributors to the gross national product, are examples of regions where the underlying rate of demand growth has been declining since 1974.

5.2.2 Analysis of Past Demand

Any economic forecast of future events must accommodate the past, rationalize the present, and provide a smooth transition into the future. This is particularly true for electric energy forecasting. Because of the turbulence and nature of the events of the 1970's (because growth rates were so different at the end of the decade as compared to the beginning), it is therefore crucial that this period be carefully analyzed for clues and reasons for changes. In the analysis that follows, historical demand has been extensively scrutinized.

Two purposes have been served. First, for each business cycle and region for which there is data, the succession of maximum and minimum growth rates are evaluated; these rates provide evidence as to the long-term direction of the underlying regional growth. Second, as will be noted, the regional cyclical changes of growth rate correspond at the same frequency, and peak and trough, at almost the identically same time (because of the efficiency of the national economy). The result is that when a relative price change occurs to electricity in a specific region (for example, because oil or gas prices go up in regions where that fuel is the major energy source), the peak or trough of a business cycle shows up as having achieved a new high or low energy use rate. These cycles are identified (for example, in New England in 1974 and 1978) in the following analysis.

Both business cycles and regional cyclical changes in growth rates are used to ratify a new view of future regional growth rate. In the data and discussion that follow, such an analysis is developed. From these the Dames & Moore regional growth rates are assumed. In the following discussions, both overall growth rates, business cycle effects, and regional restructuring are examined. First, electricity sales and their relationship with the business cycle are examined.

Fluctuations in the demand growth patterns of electricity sales (Exhibit 1) reflect a strong correlation with swings in the business cycle. Between 1957 and 1980, the business cycle experienced five major troughs (1958, 1961, 1970, 1974, 1980) and five major peaks (1957, 1960, 1969, 1973, 1977). The plot of electricity demand growth in Exhibit 1 closely emulates these major troughs and peaks. Since electricity is a major input into the production of goods and services in the economy, any slowdown in the production of goods due to economic conditions is immediately reflected in the sale of electricity. Thus, the business cycle is a major determinant of the demand for electricity.

In contrast, the regional analysis is more complicated. To illustrate this, patterns of electricity demand growth for each of the seven composite regions are presented in Exhibits 3 through 11. Although the general patterns reflect the national business cycle, the magnitude of fluctuations and cycling depends on the electricity demand base (i.e., residential, commercial, industrial), the type of fuel base, and the region's relative influence on the U.S. economy. Regions with one or more of these characteristics in common display similar demand growth patterns.

The New England (Exhibit 3), Mid-Atlantic (Exhibit 4), and Central Industrial (Exhibit 5) regions experienced similar electricity demand growth rates during the 1957 to 1980 period. These regions have a large industrial and commercial demand base and therefore have a substantial influence on the United States business cycle. As evident in the exhibits, the regions exhibited major fluctuations in the growth pattern indicative of the recessions and recoveries occurring between 1957 and

1963. Growth remained steady until 1972 when the economy dipped into a recession. The 1974-1976 recession is evident in the three regions' demand growth patterns. The New England and Mid-Atlantic regions experienced steady growth rates after the oil embargo, although a slight decreasing trend in the underlying rate of growth has occurred in the post-embargo years. The Central Industrial region, on the other hand, was still experiencing a great deal of fluctuation in demand growth after the 1975 recovery period, and the magnitude of these fluctuations throughout the 1957 to 1980 period was greater than in the other geographical regions (negative rates of growth occurred in 1959, 1975, and 1980). One cause of the Central Industrial region's low demand growth in 1980 has been the slump in U.S. automobile manufacturing. Electricity is a major factor in automobile production, and the recent sales downturn in the industry has resulted in lower rates of growth in electricity demand. There are no indications that the underlying growth rate in demand will deviate from its present downward trend. The economic variables driving the demand forecast on its present path (e.g., gross national product, inflation, production of domestic automobiles) show little indication of changing dramatically in the next few years. The forecasts presented by Dames & Moore reflect this sustained downward trend in the underlying growth rate. It is unlikely, in view of recent history, that the Median and Projection II growth rates will occur.

Demand growth rates in the Southeast region (Exhibit 6) were not greatly affected by events in the economy between 1957 and 1963. Although growth rates did decline substantially in 1959, the magnitude of the fluctuations after 1959 remained relatively stable until 1973; since then, growth rate fluctuations have been of a much larger magnitude. As in the regions discussed above, the underlying rate of demand growth has declined since 1970. We see no reason to suspect a reversal of this trend. The South's sufficient supply of relatively inexpensive labor will continue to restrain any extensive increase in capitalization that may have resulted from the industrialization occurring in the South. The lower forecast of demand growth for the region advocated by Dames & Moore reflects the historic trend.

The Pacific Northwest (Exhibit 7) and South Central (Exhibit 8) regions' demand growth fluctuated consistently throughout the 1957 to 1980 period. Only the years 1964 through 1969 display somewhat stable growth rates. The Pacific Northwest experienced negative rates of growth in 1959, 1978, 1980, and 1981. In contrast the South Central region experienced a major increase in the rate of growth during 1962 and 1963, resulting from a substantial amount of new industrialization occurring in the South as industries relocated there to take advantage of lower labor costs. The demand growth patterns of these two regions reflect the most encouraging growth in the United States. The Pacific Northwest shows a slightly upward trend beginning in 1975, while the South Central region displays the standard downward trend in demand growth. In the past, the Pacific Northwest's industrial development has been enhanced by the supply of inexpensive hydroelectricity used as a production input. Recently, however, the Pacific Northwest utilities have been forced to increase their prices to a level more reflective of the rest of the country due to capacity constraints. Hence, it is reasonable to assume a slowdown in the rate of demand growth in this region as the price of electricity continues to rise.

The West Central region (Exhibit 9) maintained relatively stable rates of growth in demand between 1957 and 1980. Although the major business cycle fluctuations noted above do appear in its demand growth patterns, the magnitude of the fluctuations are not as dramatic as those occurring in other regions, possibly because the region is primarily an agriculturally-based economy. Usually, this type of economy will be somewhat affected by national recessions and expansions, but not to the same extent as an industrially- or commercially-based economy. The region has been affected by the recent 1979-1980 recession, which resulted in slightly negative growth rates. Peaks in demand growth occurred at relatively the same level throughout the period. While the oil embargo of 1973 did not change the level of the demand growth peaks, it did result in a lowering of the underlying growth rate. We see no indication that the underlying rates of growth will be reversed. This trend is reflected in the Dames & Moore forecast.

In the Rocky Mountain (Exhibit 10) region, demand growth rates have fluctuated to a greater extent than in any other region except the Pacific Northwest. The underlying growth rate, however, has been relatively stable throughout the period, probably because the region's major industry is mining, which has little impact in determining business cycles. The Pacific Southwest region (Exhibit 11) displayed a definite declining trend in its demand growth rates from 1957 to 1980. Negative rates of growth occurred during 1974, 1975, and 1976. For the most part, all other regions show similar declining growth rates after 1974 with the exception of the Pacific Northwest, West Central, and South Central regions. Both regions display a decisive downward trend in the rate of demand growth. The Pacific Southwest region has met with considerable constraints on capacity development and as a consequence, has discouraged further commercial and industrial development through increases in the price of electricity. Both regions are forecast to retain their downward trends in the rate of demand growth as reflected in the Dames & Moore forecast.

As can be seen from the analysis, the regional rate of demand growth is closely related to the national business cycle, particularly in areas where the regional economy is a significant component of the national economy. Regional differences in commerce and industry determine the magnitude of the fluctuations in regional demand growth as demand growth follows the business cycle. Hence, regional demand growth analyses based on business cycle analyses prove useful in the development of future regional demand growth.

5.2.3 Demand Forecasts

Three scenarios of demand growth are incorporated into the pumped storage analysis. The Corps of Engineers has requested that two demand growth scenarios presented in the study, "The Magnitude and Regional Distribution of Needs for Hydropower," July 1980, be used in conjunction with our analyses. The Projection II figures, presented as Table 5-2, give an average annual compound growth rate of 3.4 percent for total energy demand between the years 1978 and 2000. Growth is expected to be largest in the Florida region, followed by the Arizona-New Mexico region. The lowest overall growth projection is forecast for the Mid-Continent Area Reliability region. Growth in the New England, New York, Mid-Atlantic and East Central regions is projected to be somewhat higher between 1985 and 1990 than between 1978 and 1985. All growth rates are expected to remain constant between 1990 and 1995, but at a slightly lower rate than during the previous decade.

The second scenario for demand growth requested by the Corps of Engineers was the Median Projection (Table 5-3). The Median Projection is the median forecast represented by Projections I, II, and III in the aforementioned study. The Median Projection forecasts an average annual demand growth rate of 4.4 percent, and the projections generally are higher than the Projection II growth rates. The lowest demand growth rate region is projected to be the Mid-Atlantic, while the Florida and Arizona-New Mexico regions are projected to have the highest rates.

TABLE 5-2

Hydroelectric Pumped Storage Analysis Projections of Energy Demand Growth

Projection II

NERC Region*	1978-1985	1985-1990	1990-1995	1995-2000
NEPOOL	3.3%	3.5%	3.3%	3.3%
NYPP	2.8	3.4	3.3	3.3
MAAC	3.0	3.4	3.3	3.3
Florida	5.3	4.1	4.1	4.1
Southern	3.8	3.7	3.2	3.2
TVA	3.9	3.8	3.3	3.3
VACAR	4.0	4.1	3.6	3.6
ECAR	3.2	3.4	3.2	3.2
MAIN	3.1	3.3	3.2	3.2
MARCA	3.1	3.1	3.0	3.0
SPP	3.6	3.2	3.0	3.0
ERCOT	4.1	3.8	3.4	3.4
RMPA	4.3	3.6	3.3	3.3
NWPP	3.8	3.3	3.1	3.1
AZNM	5.0	4.1	3.6	3.6
SCNV	3.8	3.7	3.4	3.4
NCNV	4.2	3.9	3.4	3.4

*NEPOOL = New England; NYPP = New York; MAAC = Mid-Atlantic Area; Florida; South Central; TVA = Tennessee Valley Authority; VACAR = Virginia-The Carolinas; ECAR = East Central; MAIN = Mid-Atlantic; MARCA = Mid-Continent; SPP = Southwest; ERCOT = Texas; RMPA = Rocky Mountains; NWPP = Northwest; AZNM = Arizona-New Mexico; SCNV = Southern California-Nevada; NCNV = Northern California-Nevada.

TABLE 5-3

Hydroelectric Pumped Storage Analysis Projections
of Energy Demand Growth

Median Projection

NERC Region*	1978-1985	1985-1990	1990-1995	1995-2000
NEPOOL	5.2%	3.3%	3.1%	3.6%
NYPP	2.8	3.4	3.3	3.3
MAAC	3.6	2.9	3.0	3.0
Florida	6.3	4.8	4.1	4.1
Southern	6.2	4.6	4.6	3.8
TVA	5.9	3.7	3.1	2.6
VACAR	6.0	5.6	4.3	4.2
ECAR	4.5	4.6	4.5	3.5
MAIN	4.7	4.3	2.9	3.9
MARCA	5.0	4.5	3.7	3.6
SPP	5.4	4.6	3.7	3.6
ERCOT	4.9	4.8	4.7	4.6
RMPA	6.3	5.0	4.0	3.9
NWPP	5.5	4.3	3.9	3.9
AZNM	6.9	5.6	4.3	4.2
SCNV	3.8	3.7	3.4	3.4
NCNV	4.2	3.9	3.4	3.4

*NEPOOL = New England; NYPP = New York; MAAC = Mid-Atlantic Area; Florida; South Central; TVA = Tennessee Valley Authority; VACAR = Virginia-The Carolinas; ECAR = East Central; MAIN = Mid-Atlantic; MARCA = Mid-Continent; SPP = Southwest; ERCOT = Texas; RMPA = Rocky Mountains; NWPP = Northwest; AZNM = Arizona-New Mexico; SCNV = Southern California-Nevada; NCNV = Northern California-Nevada.

The third scenario for demand growth was devised by Dames & Moore (Table 5-4). These rates of growth are substantially lower than those projected by the other forecasts. The annual average compound growth rate between 1979 and 1999 is expected to be 2.6 percent. The Rocky Mountain and Arizona-New Mexico regions are projected to be the fastest growing energy regions, while the New England and New York regions are projected to have the lowest rates of growth between 1978 and 1999.

TABLE 5-4

Hydroelectric Pumped Storage Analysis Projections
of Energy Demand Growth

Dames & Moore Projection

NERC Region*	1978-1985	1985-1990	1990-1995	1995-2000
NEPOOL	1%	1%	1%	1%
NYPP	1	1	1	1
MAAC	2	2	2	1
Florida	4	3	3	3
Southern	2	2	2	2
TVA	3	3	2	1
VACAR	4	4	3	2
ECAR	2	3	2	2
MAIN	3	4	3	3
MARCA	4	4	3	3
SPP	4	3	3	2
ERCOT	4	3	3	2
RMPA	5	4	3	3
NWPP	3	3	2	2
AZNM	5	4	3	3
SCNV	2	2	1.5	1.5
NCNV	2	2	1.5	1.5

*NEPOOL = New England; NYPP = New York; MAAC = Mid-Atlantic Area; Florida; South Central; TVA = Tennessee Valley Authority; VACAR = Virginia-The Carolinas; ECAR = East Central; MAIN = Mid-Atlantic; MARCA = Mid-Continent; SPP = Southwest; ERCOT = Texas; RMPA = Rocky Mountains; NWPP = Northwest; AZNM = Arizona-New Mexico; SCNV = Southern California-Nevada; NCNV = Northern California-Nevada.

5.3 REGIONAL FORECASTS OF PUMPED STORAGE OR ALTERNATIVE PEAKING CAPACITY

In the analysis that follows, the need for pumped storage or alternative peaking capacity is calculated. The forecast horizon is 1981 through the turn of the century. A series of demand-supply scenarios for each region were computed using an economic dispatch computer program. The important variables in the calculations were demand growth rates, rates of retirement for existing generating capacity, assumptions about fuels used to power pumped storage, and fuels displaced by new pumped storage.

The calculated results for the different scenarios vary significantly in accordance with the three demand scenarios. The growth rates most likely to result under the current economic environment are those forecast by Dames & Moore. An evaluation of the three demand forecasts was presented in Section 5.2.3.

As will be shown, even for the lowest growth rates projected, prospects are dim for achieving estimated required amounts of pumped storage in the current economic setting. Severe shortages of peaking capacity are probable in the early 1990's--even under these low-growth forecasts. Unless the financial and economic environment confronting the utilities improves, the need for peaking capacity by 1995 may have grown to levels that are clearly unsupportable in terms of current construction plans. A detailed analysis of the results and implications of these forecasts follows.

5.3.1 Overview of Results

Based on our analysis (and on economic reasoning and previous history), the actualization of the following combination of conditions is most likely to bring about pumped storage capacity development: (1) Dames & Moore's load growth projections; (2) utility-announced retirements; (3) the dispatch of pumped storage after all other fuel types; and (4) load management techniques not presently in effect. A detailed description of each of these conditions and how they were derived appears in Section 5.3.2, but briefly, the choice of Dames & Moore's load growth projection was discussed above, and utility-announced retirements are presented on the schedule of retirements compiled by NERC from utility reports (Table 5-9, p. 5-31). Utility plants probably will be maintained for longer periods of time than in the past since the capital costs of building a new plant are now so high. The same rationale applies to the dispatch order of pumped storage; utilities will choose to operate the plants currently on line rather than replace them with new pumped storage plants, which have higher short-run capital costs although they are the most cost effective in the long run. In implementing load management techniques, by the year 2000 the capacity factor will be reduced by 10 percent (according to DOE); Dames & Moore, however, considers this estimate to be too optimistic.

The combination of this particular group of conditions results in an estimate of pumped storage capacity development for the continental United States of 59,875 megawatts (MW) by the year 1999. It should be restated that this estimate does not consider the environmental, physical, and geographical factors that affect the development of pumped storage capacity. The estimated supportable pumped storage energy is 24,175 gigawatt-hours (GWh).

Unsited base capacity development needed in conjunction with pumped storage capacity development is estimated at 8,478 MW in 1999. Table 5-5 is a summary table of the future demand for pumped storage in the continental United States in 1999; maximum pumped storage development for each region is presented in Table 5-6; and detailed results are presented in Table 5-7.

The ECAR-MAIN-MARCA composite region is estimated to have the greatest potential for pumped storage capacity development, followed by the Southern-TVA-VACAR composite region. The RMPA-NWPP composite region is estimated to have no potential for pumped storage development. These conclusions are based on various scenarios that alter the combination of the determinants. In our best judgment, the estimated potential as shown represents the maximum amount of pumped storage development possible for each region. A detailed description of the analysis that preceded our conclusions is presented below.

Puerto Rico was not included in the DISPATCH calculations to assess the potential for pumped storage development in the United States. Although Puerto Rico has experienced power shortages, the lack of new capital prevents Puerto Rico from investing in new capacity. The current capacity in Puerto Rico is oil based. We believe it is unlikely that Puerto Rico can afford to finance either coal or pumped storage plants. Therefore, the potential for pumped storage development in Puerto Rico is poor at best.

TABLE 5-5

Summary Table for Future Demand
Assessment of Pumped Storage
Continental USA - 1999

	Projection II		Median Projection		Dames & Moore Projection	
	Base Load Shape (MW)	Load Mgt. Techniques (MW)	Base Load Shape (MW)	Load Mgt. Techniques (MW)	Base Load Shape (MW)	Load Mgt. Techniques (MW)
Utility Announced Retirement Schedule						
1. After coal steam	250,273	143,412	301,868	178,498	180,342	105,812
2. After oil steam	221,585	121,960	297,578	172,999	140,831	79,957
3. After all other fuel types	149,969	47,274	223,234	94,239	59,875*	17,161
Generic Retirement Schedule						
1. After coal steam	254,484	146,200	301,868	178,498	188,376	107,499
2. After oil steam	245,545	138,632	301,868	178,498	165,484	93,796
3. After all other fuel types	195,213	81,564	248,575	122,275	116,641	41,370

*Base Case Projection

TABLE 5-6

Maximum Pumped Storage Development by Region

	Maximum Pumped Storage Capacity
Continental United States	59,875 MW[1]
New England; New York; Mid-Atlantic (NEPOOL-NYPP-MAAC)	3,353
Florida	5,254
Southern; Tennessee Valley; Virginia-Carolinas (Southern-TVA-VACAR)	13,399
East Central; Mid-America; Mid-Continent (ECAR-MAIN-MARCA)	35,981
Southwest; Electric Reliability Council of Texas (SPP-ERCOT)	1,314
Rocky Mountains; Northwest (RMPA-NWPP)	0
Arizona-New Mexico; Southern California-Nevada; Northern California-Nevada (AZNM-SCNV-NCNV)	574

[1] Based on Dames & Moore's load growth projections, utility-announced retirement schedule, dispatch of pumped storage after all other fuel types, and load management techniques not presently in effect.

Hydroelectric Pumped Storage Analysis
Pumped Storage Forecast For - Continental U S A -

Utility Announced Retirements Only

	Projection II			Median Projection			Dames & Moore Projection		
	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	96864	98744.	86072.	96864.	98744.	86072.	96864.	98744.	86072.
1985	122635.	126717.	82604.	144853	143327	96339.	110852.	116567.	71957.
1990	145342.	153801.	77863	210766.	189664.	109048.	117066.	134382.	50362.
1995	213868	201377.	121069.	329365.	257212	211963.	151200.	159873.	68013.
1999	310282.	250273.	198812.	392824	301868.	313158.	188507.	180342	95425.
Pumped Storage Dispatched After Oil Steam									
1979	35888	74180	0.	35888.	74180.	0.	35888.	74180.	0.
1985	47914.	96496.	0.	56692	105515.	1524.	43706.	89067.	0.
1990	60600.	118071.	0.	88454.	138967	1393.	50046.	102925.	0.
1995	117970.	161018.	8282.	255418.	229732.	65204.	60821.	119765.	0.
1999	235174.	221585	58992.	360249.	297578.	155275.	91529	140831.	6925.
Pumped Storage Dispatched Last									
1979	1924.	7455.	0.	1924.	7455.	0.	1924.	7455.	0.
1985	4756.	18568.	0	9052.	30813	260.	3405.	13754.	0.
1990	10429.	35237	5573.	29864.	65751.	11943.	5903.	20740.	0.
1995	32753.	90392.	24688.	125314.	167501	86685.	11147.	37309.	305.
1999	96816.	149969.	81977.	186622	223234	185698.	24175.	59875.	8478.
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	96864.	98744.	86072	96864.	98744	86072.	96864.	98744.	86072.
1985	99568.	105969.	81455.	114712	117059.	94738.	91743.	100872.	70703.
1990	99113.	113153.	75159.	141045.	137088	104264.	81079	97267.	44968.
1995	112064.	123871.	114633.	204232.	167238	203403.	89678.	103018.	63267.
1999	162426.	143412.	188512.	221333.	178498.	301544.	104178.	105812.	89141.
Pumped Storage Dispatched After Oil Steam									
1979	35888.	74180.	0	35888.	74180	0.	35888.	74180.	0.
1985	38918.	80806.	0.	43932.	88222.	1330.	36184.	77290	0.
1990	40399	86404.	0.	53477	97862	847.	35834.	75648.	0
1995	57417.	98610.	6065.	144607.	142143.	58709.	35754.	75941.	0.
1999	108311.	121960.	51743	198057.	172999	143521.	44213.	79957.	5634.
Pumped Storage Dispatched Last									
1979	1924	7455	0	1924	7455	0.	1924	7455.	0.
1985	2004.	8970	0.	4375	15640	469	1676	7827.	0.
1990	2636	9973	0	10880	27082	2066.	1904.	7837.	0.
1995	6074	23898	6003	53518	73611.	52114.	2684	11803.	0.
1999	21924	47274	37386.	72311.	94239.	125785.	4637	17161	4491

Hydroelectric Pumped Storage Analysis
Pumped Storage Forecast For - NEPOOL - NYPP - MAAC -

Utility Announced Retirements Only

	Projection II			Median Projection			Dames & Moore Projection		
	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	27459	21106.	25573	27459	21106.	25573.	27459.	21106.	25573.
1985	33937	26132	26536.	35623.	27372.	29876.	30131.	23272.	19853.
1990	39741	30663.	29051.	41088.	31619.	31777.	26572.	24086.	12943.
1995	47681.	36792.	40710.	48782	37537.	42933.	31130.	26629.	14006.
1999	55032.	42464.	54837	56471.	43440.	57740.	32703.	27948.	16542.
Pumped Storage Dispatched After Oil Steam									
1979	6534.	12410.	0	6534.	12410.	0.	6534.	12410.	0.
1985	8121.	15355.	0	8933.	16090.	0.	7193.	13662.	0.
1990	10648	19125	0.	12787.	20085.	0.	6575.	14706.	0.
1995	28348	29402.	4021.	33457.	31577.	6573.	7175.	15956.	0.
1999	47224	39557	16223	50835.	41740.	19125.	8819.	17936.	0.
Pumped Storage Dispatched Last									
1979	0	0.	0.	0.	0.	0.	0.	0.	0.
1985	0.	0.	0	104.	496.	0.	0.	0.	0.
1990	577.	2752.	1029.	682.	3251.	1204.	0.	0.	0.
1995	4846.	15074.	7142.	4888	16047.	10355.	316.	1507.	305.
1999	8768	23041.	20513	9343.	24307.	25354.	703.	3353.	979.
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	27459	21106.	25573	27459.	21106.	25573.	27459.	21106.	25573.
1985	28531.	22176.	26184.	30021.	23280.	29524.	23382.	20009.	19133.
1990	26871	23055.	27856.	27947.	23825.	30565.	15611.	13483.	8634.
1995	28025	24306.	38992.	28804.	24838.	41194.	18112.	13823.	11706.
1999	28802.	25225.	52614.	29719.	25857.	55484.	16831.	12955.	13904.
Pumped Storage Dispatched After Oil Steam									
1979	6534	12410.	0	6534	12410	0.	6534.	12410.	0.
1985	6784	13014.	0.	7112	13668	0.	5155.	11730.	0.
1990	5969	13689	0.	6663	14145	0.	3655	7451.	0
1995	14565	19213	3523	18046.	20123.	5816.	3454.	7122.	0
1999	23664	22374	14063.	27029	24483	16933.	3172.	6627.	0.
Pumped Storage Dispatched Last									
1979	0	0	0	0	0	0.	0.	0.	0
1985	0.	0	0	0	0	0.	0	0.	0
1990	0	0	0	0.	0	0.	0	0	0.
1995	1074	5119	4138	1033	4927	4094.	0	0.	0
1999	1548	6570	9592	1526	6518.	9375	0	0.	0

Table 5-7 (cont'd)

Hydroelectric Pumped Storage Analysis
Pumped Storage Forecast For - Florida -

Utility Announced Retirements Only

	Projection II			Median Projection			Dames & Moore Projection		
	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	11300.	9196.	9973.	11300	9196.	9973	11300	9196	9973.
1985	17914.	14289	11809	17914	14289	11809	14160.	11525.	9895.
1990	22884.	18228.	12392	22884	18228	12392.	16418.	13361.	7852
1995	27982	22287	18581.	27982	22287	18581.	19035	15490	11558
1999	32867.	26176	24511.	32867.	26176	24511.	21427.	17435	14944
Pumped Storage Dispatched After Oil Steam									
1979	2842.	5419.	0.	2842.	5419	0.	2842.	5419	0.
1985	4505	8419.	0.	4505	8419	0.	3561.	6791.	0.
1990	5754	10739.	0	5754.	10739	0.	4129.	7872.	0
1995	20029	18137.	2088	20029	18137.	2088.	4786.	9126	0.
1999	32272.	25856.	8174	32272.	25856.	8174.	7246.	10894	0.
Pumped Storage Dispatched Last									
1979	0	0.	0.	0.	0	0.	0.	0.	0.
1985	289.	1401.	0	289.	1401.	0.	0.	0.	0
1990	1364.	4439.	1653	1364.	4439	1653.	0.	0.	0.
1995	5354.	12496	5625.	5354.	12496	5625.	232.	1126	0
1999	9468	17405.	11926.	9468	17405.	11926.	1084.	5254.	373
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	11300	9196	9973	11300.	9196.	9973.	11300.	9196	9973
1985	13588	11118.	11565	13588	11118	11565.	12489.	10219	9809
1990	15287.	12628	11978	15287.	12628	11978	12883.	10643	7674
1995	16751.	13947	17971	16751.	13947	17971.	13386.	11146	11269.
1999	17977	15084.	23702	17977.	15084	23702.	13767	11553	14548.
Pumped Storage Dispatched After Oil Steam									
1979	2842	5419.	0.	2842.	5419	0.	2842	5419	0.
1985	3417	6552.	0	3417	6552.	0.	3141	6022	0.
1990	3883	7490.	0	3883	7490	0.	3273.	6313	0.
1995	8160	9305	1388.	8160	9305	1388.	3400	6612	0
1999	16122	14085	7365	16122	14085	7365.	3497.	6853.	0
Pumped Storage Dispatched Last									
1979	0.	0.	0	0.	0	0	0	0	0
1985	0	0	0	0	0	0	0.	0	0
1990	0	0	0	0	0	0	0	0	0
1995	756	3665	1642	756	3665	1642	0	0	0
1999	1255	6082	5109	1255	6082	5109	0	0	0

Hydroelectric Pumped Storage Analysis
Pumped Storage Forecast For - Southern - TVA - VACAR -

Utility Announced Retirements Only

	Projection II			Median Projection			Dames & Moore Projection		
	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	8779	13715.	0	8779.	13715.	0.	8779.	13715	0.
1985	9956.	18083.	0.	20189	23008.	2459.	8987.	16875.	0
1990	14798.	22813	0	39465.	32694.	6730.	11921.	19875	0
1995	29005.	31270	1262	67781.	48061	25470.	14165.	22519.	0
1999	53479.	41187.	14982	85706	56969	42344.	14879.	24069.	0
Pumped Storage Dispatched After Oil Steam									
1979	5934	13630.	0	5934	13630	0.	5934.	13630.	0.
1985	8285.	18083.	0.	13736.	21768	1524.	7619.	16875.	0.
1990	10900.	22652.	0.	27476.	29440.	1393.	9388.	19875.	0.
1995	19253.	28562	1044	65836	46934	19530.	10914.	22430.	0.
1999	41754	37158	10234	85706.	56969	36406.	11898	24069.	0.
Pumped Storage Dispatched Last									
1979	938.	2757.	0.	938.	2757.	0.	938.	2757.	0.
1985	2234.	7156.	0	4674.	12079.	260.	1768	5946	0
1990	4565.	12143.	0	16860.	22708	2407.	3268.	9205.	0.
1995	9585.	20597.	0.	47633.	41290	17717.	4454	11847.	0.
1999	29209.	31952.	8309.	68205	52405	34751.	5077.	13399.	0.
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	8779	13715.	0.	8779.	13715	0.	8779.	13715	0.
1985	7118.	15210	0	13886	18230	2000.	6757.	14507	0
1990	8654	16669	0.	28706.	24328	6034.	7392	15203.	0.
1995	11056.	17656	598	42673	30788	23743	6931.	15165	0.
1999	22773	20697	12803	50528.	33370.	39953.	6426.	14640	0.
Pumped Storage Dispatched After Oil Steam									
1979	5934	13630	0	5934.	13630	0.	5934.	13630.	0
1985	6669	15210	0	9290	18112	1330.	6308.	14507	0.
1990	7455	16669	0	16128.	20690.	847.	6686	15203	0
1995	8043	17656	598	40854.	29385	17804.	6705	15165	0.
1999	16876	20688	9017	50528	33370.	34013.	6426	14640	0
Pumped Storage Dispatched Last									
1979	938.	2757	0	938	2757	0.	938	2757	0
1985	1020	4281	0	2626	7301	469.	785	3579	0
1990	1802	5998	0	8064	13659	2066.	1210	4531	0
1995	2539	6985	223	24926	23480	15976.	1150.	4494	0
1999	8010	10888	7119	32944	28961	32212	965	3767	0

Table 5-7 (cont'd)

Hydroelectric Pumped Storage Analysis
Pumped Storage Forecast For - ECAR - MAIN - MARCA -

Utility Announced Retirements Only

	Projection II			Median Projection			Dames & Moore Projection		
	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	13365	24491	0.	13365	24491.	0	13365.	24491	0.
1985	16022	30033	0	21768.	36861.	0.	14689.	27831.	0.
1990	19456	35772.	0.	44571.	54116.	5136	18749.	34103	0.
1995	48058.	54984.	7807	106041	84010.	46406.	34001.	45398	2643
1999	92656.	76069	31435	124774	98434	80551	55805.	56241.	13281.
Pumped Storage Dispatched After Oil Steam									
1979	12219.	23398.	0.	12219	23398.	0.	12219.	23398.	0
1985	16022.	30033	0	17680.	32961.	0.	14689.	27831.	0.
1990	18944	35284.	0	26298.	44967.	0.	17538.	32948.	0.
1995	27655	45834	0.	104299.	83292.	33981.	23558	40862.	0
1999	78614.	70891	18447.	124774	98434.	68186.	47823.	53882	6925
Pumped Storage Dispatched Last									
1979	986.	4698	0	986.	4698	0.	986.	4698.	0.
1985	2233	10011.	0.	3985.	16837.	0.	1637.	7808.	0.
1990	3357.	13204.	0	10160.	31547.	714.	2635.	11535.	0.
1995	10910	32414.	1904	61664	70501.	29207.	6145.	22829.	0
1999	44944	58066.	17294	87622.	88155.	62758.	16915	35981.	4486.
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	13365.	24491	0	13365.	24491.	0.	13365.	24491.	0.
1985	12801	24712.	0.	15465.	28362.	0.	12580.	24271.	0.
1990	13335	25952.	0	22627	35884	3874.	13145.	25548	0.
1995	18549.	30698	6156.	64640	53784	43965.	18889.	29877.	2102.
1999	49364	43858	28807.	68941	57723	77289.	32146.	34177	12166
Pumped Storage Dispatched After Oil Steam									
1979	12219	23398.	0.	12219.	23398.	0.	12219.	23398.	0.
1985	12801.	24712.	0	14097.	27058	0	12580	24271	0.
1990	13335	25952.	0.	15620	30118.	0	13145.	25548	0
1995	13682	26949.	0	60296	52384.	31274	13131.	25804	0.
1999	33550	37153	16040	68941.	57723.	64876.	22376.	31094.	5634
Pumped Storage Dispatched Last									
1979	986.	4698	0	986	4698	0.	986.	4698	0.
1985	984.	4689	0	1749	8339	0.	891	4248	0
1990	834	3975	0	2793.	13315	0	694	3306	0
1995	1705	8129	0	26376	39505	28824.	1534	7309.	0.
1999	11111	23734	15566	35327	47314	59118.	3672	13194	4491

Table 5-7 (cont'd)

Hydroelectric Pumped Storage Analysis
Pumped Storage Forecast For - SPP - ERCOT -

Utility Announced Retirements Only

	Projection II			Median Projection			Dames & Moore Projection		
	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	25816	21016.	36819	25816.	21016	36819	25816.	21016.	36819
1985	33529.	27153	30894	36566	29624	37580.	32989	26781.	31138
1990	34562	32756.	21902	46979	37955.	35959.	32348	31340	20031.
1995	42739.	38626.	33261	58189.	46898	55693.	39633.	36251	29069.
1999	54690.	44034	47969	68711	55285	78520.	48485.	39392.	37791.
Pumped Storage Dispatched After Oil Steam									
1979	6293	13368.	0.	6293.	13368	0.	6293.	13368.	0.
1985	8250.	17017	0.	9021.	18482	0.	8113.	16796.	0.
1990	10036	20339.	0.	11664	23421	0.	9554.	19499	0.
1995	11902	23819.	0.	18279	32251.	0.	11107.	22411.	0.
1999	16088	29377	0	44103	53015	13522	12099	24273.	0.
Pumped Storage Dispatched Last									
1979	0	0.	0.	0.	0.	0	0.	0.	0.
1985	0.	0	0	0.	0.	0.	0.	0.	0
1990	0	0	0.	232	1107.	3074.	0.	0.	0.
1995	765	3648	4848.	3905	18613.	17034.	0.	0.	0.
1999	2269	10814.	14284	8744.	28968.	37849.	276.	1314.	2640.
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	25816	21016	36819	25816.	21016.	36819.	25816.	21016.	36819.
1985	28227	23057.	30503	30881.	25229	37161.	28366.	23185	30795
1990	25103	24399.	21107.	34667.	28430	35051.	24486	23969.	19328.
1995	25966	25280	31989.	37490.	30892	54169.	24794.	24368.	27936.
1999	31168.	25860.	46238	39488	32700	76369.	27404.	23743	36299
Pumped Storage Dispatched After Oil Steam									
1979	6293	13368.	0	6293.	13368	0.	6293	13368.	0
1985	6904	14588	0	7578	15876.	0	6939	14564.	0
1990	7291	15384	0	8539.	17774	0.	7146.	15129	0.
1995	7518	15906.	0	9256	19234	0.	7220.	15366.	0
1999	7651.	16251	0	22224.	29574	11217.	6978.	14995	0
Pumped Storage Dispatched Last									
1979	0	0	0	0	0	0.	0	0.	0
1985	0	0	0	0	0	0	0	0	0.
1990	0	0	0	0	0	0	0	0	0.
1995	0	0	0	0.	0	0.	0	0	0.
1999	0	0	0	595	2837	16553.	0	0	0

Table 5-7 (cont'd)

Hydroelectric Pumped Storage Analysis
Pumped Storage Forecast For - RMPA - NWPP -

Utility Announced Retirements Only

	Projection II			Median Projection			Dames & Moore Projection		
	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	0	0	0	0.	0	0	0	0	0
1985	0	0	0	0	0	0	0	0	0.
1990	0	0	0.	0.	0	0.	0	0	0
1995	0	0	0	0.	0	0.	0.	0	0.
1999	0	0	0	0.	0	0.	0	0	0
Pumped Storage Dispatched After Oil Steam									
1979	0.	0.	0.	0.	0	0.	0.	0.	0
1985	0	0.	0	0	0	0.	0.	0.	0
1990	0	0.	0.	0	0	0.	0.	0	0
1995	0	0	0	0.	0	0.	0.	0.	0.
1999	0	0.	0.	0.	0	0.	0.	0	0
Pumped Storage Dispatched Last									
1979	0.	0	0	0.	0.	0	0	0.	0.
1985	0.	0.	0	0	0	0.	0	0.	0.
1990	0.	0	0	0	0	0.	0.	0.	0
1995	0.	0.	0	0	0	0.	0.	0.	0.
1999	0	0.	0	0.	0.	0	0	0.	0
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	0.	0	0	0.	0	0.	0	0.	0.
1985	0	0.	0.	0	0.	0	0	0	0.
1990	0	0	0	0.	0	0	0	0	0.
1995	0	0	0	0	0	0.	0	0.	0.
1999	0.	0.	0	0.	0	0	0	0	0.
Pumped Storage Dispatched After Oil Steam									
1979	0.	0	0.	0	0	0	0	0	0.
1985	0	0	0	0	0	0.	0	0	0
1990	0	0	0	0	0	0.	0.	0	0.
1995	0	0	0.	0	0	0.	0	0	0
1999	0	0	0	0	0	0.	0.	0	0
Pumped Storage Dispatched Last									
1979	0	0	0	0	0	0	0	0.	0
1985	0	0	0	0	0	0	0	0	0
1990	0	0	0	0	0	0	0.	0	0
1995	0	0	0	0	0	0	0	0	0
1999	0	0	0	0	0	0	0	0	0

Table 5-7 (cont'd)

Hydroelectric Pumped Storage Analysis
Pumped Storage Forecast For - AZNM - SCNV - NCNV -

Utility Announced Retirements Only

	Projection II			Median Projection			Dames & Moore Projection		
	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	10145	9220.	13707	10145	9220	13707	10145	9220.	13707.
1985	11277	11027.	13365.	12793	12173.	14615	9896	10283	11071.
1990	13901	13569	14518	15779	15052	17054.	11058	11617.	9536
1995	18403	17418	19448	20590	18419	22880	13236.	13586.	10737
1999	21558	20343	25078	24295	21564	29492.	15208.	15257.	12867
Pumped Storage Dispatched After Oil Steam									
1979	2066	5955.	0	2066	5955	0.	2066.	5955.	0
1985	2731.	7589.	0	2817	7795	0.	2531.	7112	0
1990	4318	9932	0.	4475	10315	0	2862.	8025	0
1995	10783	15264.	1129.	13518	17541	3032	3281	8980.	0.
1999	19222	18746.	5914	22559.	21564	9862.	3644.	9777	0.
Pumped Storage Dispatched Last									
1979	0	0	0	0	0	0.	0	0.	0.
1985	0.	0	0	0	0	0.	0.	0	0.
1990	566	2699.	2891	566	2699	2891	0.	0	0.
1995	1293	6163	5169.	1870	8554	6747	0.	0	0
1999	2158	8691.	9651	3240	11994	13060	120.	574	0
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	10145	9220	13707	10145	9220	13707.	10145	9220	13707.
1985	9303	9696	13203.	10871	10840	14488.	8169.	8681	10966
1990	9863.	10450.	14218	11811	11993	16762	7562	8421	9332
1995	11717	11984.	18927	13874	12989	22361.	7566	8639	10254
1999	12342.	12688.	24348	14680	13764	28747.	7604.	8744	12224
Pumped Storage Dispatched After Oil Steam									
1979	2066.	5955	0	2066	5955	0.	2066	5755	0
1985	2343	6730	0	2438	6956	0.	2061	6096	0.
1990	2466	7220	0	2644.	7645	0	1929.	6004.	0.
1995	5449.	9581	556	7995	11712	2427	1844.	5872	0
1999	10448	11409	5238	13213.	13764	9117	1764	5748	0
Pumped Storage Dispatched Last									
1979	0	0	0	0	0	0	0	0	0
1985	0	0	0	0	0	0	0	0	0
1990	0	0	0	73	108	0	0	0	0.
1995	0	0	0	427	2034	1578	0	0	0
1999	0	0	0	664	2527	3418	0	0	0

Table 5-7 (cont'd)

5.3.2 Detailed Analysis of Results

The pumped storage, alternative peaking technology, and load management capacity development projections were calculated for each of the 17 NERC regions and subregions. To simplify the analysis, the projections of the 17 regions are aggregated into seven composite regions based on geographical location and major source of generating fuel: (1) New England, New York, Mid-Atlantic (NEPOOL-NYPP-MAAC); (2) Florida; (3) Southern, Tennessee Valley, Virginia-Carolinas (Southern-TVA-VACAR); (4) East-Central, Mid-America, Mid-Continent (ECAR-MAIN-MARCA); (5) Southwest, Electric Reliability Council of Texas (SPP-ERCOT); (6) Rocky Mountain, Northwest (RMPA-NWPP); and (7) Arizona-New Mexico, Southern California-Nevada, Northern California-Nevada (AZNM-SCNV-NCNV).

The median projection of demand growth (Table 5-3) consistently estimated the largest potential for supportable pumped storage energy and maximum pumped storage capacity development, while the Dames & Moore demand growth projection forecast the lowest (the continental United States and regional results are shown in Table 5-7). The median projection was 1.8 percent above the Dames & Moore projection, but Dames & Moore has maintained that the high median projection is not supported by recent trends in the underlying rate of growth in demand. Consequently, the Dames & Moore forecast was chosen as the most probable demand projection.

The greatest potential for pumped storage peaking capacity development (in MW) occurs in the ECAR-MAIN-MARCA region, while no potential for pumped storage development was found for the RMPA-NWPP region. (The RMPA-NWPP region relies heavily on hydro-generated energy, which can be used to meet any requirements for additional peaking capacity in the region.) This was true under all demand growth scenarios. The Southern-TVA-VACAR region shows the second largest potential for pumped storage peaking capacity development. In terms of supportable pumped storage energy development (in GWh), the ECAR-MAIN-MARCA region is estimated to have the greatest potential. This result is consistent with the pumped storage peaking capacity development estimate. Once again, the RMPA-NWPP is estimated to have no supportable pumped storage energy development. The largest unsited base-capacity development (in MW) is forecast for the ECAR-MAIN-MARCA region, followed by the SPP-ERCOT region under the after-coal dispatch scenario. The Southern-TVA-VACAR region shows a consistently large potential for unsited base development, regardless of dispatch order. These regions also are forecast to have the largest rates of growth throughout the forecast horizon, and our results indicate the need for future capacity development in these regions if growth continues to meet load growth projections.

On the supply side, Dames & Moore uses its own supply data base comprised of an inventory of all existing generating plants in the United States. The plant's name, location, owner, NERC region, summer and winter capacities, and the generating units within each plant are maintained for all electricity generating plants. The data base also contains scheduled additions and retirements as reported by NERC.

For the purposes of this analysis, generating plants were grouped by fuel type in each region and dispatched on the basis of fuel type and characterization as a base or peaking plant. The various dispatching orders were determined by Dames & Moore on the basis of economic efficiency, i.e., less expensive generating methods are dispatched first. Expected outages for each generating unit were assumed in the Dames & Moore data base with outage percentages presented in Table 5-8. Coal steam was assumed to have the highest percentage of outages. Hydro forced outages were based on a dual regional hydro capacity factor; forced outages for pumped storage were estimated to be 5 percent. Assumed maintenance periods are also contained in the Dames & Moore data base (Table 5-8); however, pumped storage is assumed to have no significant maintenance period.

Two retirement schedules were also included in the pumped storage analysis. Individual utilities must submit scheduled retirement dates to NERC, for generating units in their service area and these retirement dates are maintained in the Dames & Moore supply data base. The FORECAST/DISPATCH programs incorporate these retirements into the calculation of new capacity development needs. In the pumped storage analysis, retirements facilitate the development of new pumped storage capacity, and this retirement schedule was used in the development of Table 5-7. In addition to the reported NERC retirements, Dames & Moore has produced a retirement schedule that includes not only those units reported by NERC, but in addition, retirements based strictly on the age of a generating unit since a generating unit of a particular fuel type is assumed to have a limited serviceable life span. For example, coal-fired generating units are retired in the algorithm after 45 years of service (Table 5-9). This retirement schedule also attempts to incorporate plant efficiency into the electricity dispatch. The

TABLE 5-8

Hydroelectric Pumped Storage Analysis
Forced Outage and Maintenance Rates

Fuel/Unit Types	Forced Outage	Maintenance	Maximum Capacity Factor
Hydro	*	*	*
Nuclear	20%	12%	68%
Coal steam	30	8	62
Gas steam	10	4	86
Oil steam	10	6	84
Combined-cycle	5	6	89
Combined-cycle	10	6	84
Turbine	5	6	89
Turbine	10	6	84
Other	5	2	93
Pumped storage	5	0	40
Unsited base	20	10	70
Unsited peak	5	2	93
Purchases	0	0	100

*Hydro forced outage and maintenance are not considered individually but are combined and considered in the form (1-forced outage-maintenance), which is equal to the capacity factor for hydro. (In DISPATCH 1979, actual regional hydro capacity factors are used.)

TABLE 5-9

Hydroelectric Pumped Storage Analysis
Generic Retirement of Older Units

Fuel Type	Retirement Year
Hydro	--
Unsited base	--
Nuclear	40
Coal steam	45
Gas steam	35
Oil steam	35
Pump storage	--
Gas combined cycle	30
Oil combined cycle	30
Gas turbine	30
Oil turbine	30
Other	--

potential for pumped storage development is greater under the Dames & Moore generic retirement schedule for all dispatching orders and growth scenarios.

Retiring older units at a faster rate increases the likelihood of installing pumped storage as a means of meeting peak capacity needs. The Dames & Moore generic retirement schedule results are presented in Table 5-10. Based on potential plant retirements, the ECAR-MAIN-MARCA region is estimated to have the largest potential for both pumped storage peaking capacity development and supportable pumped storage energy; the Southern-TVA-VACAR region has the second largest potential. The SPP-ERCOT region is second largest in the potential for unsited base development under the generic retirement schedule; no unsited base development potential is estimated for the Southern-TVA-VACAR region or the RMPA-NWPP region.

Although the years of service of a generating unit should be a major factor in a retirement decision, financial restraints may prove to be even more important. Utilities usually project retirements no more than 10 years into the future, and consequently, in this time of financial uncertainty, the utility-announced retirement schedule may prove to be the best indicator of future plant retirements. Utilities will probably continue to use older generating units longer because the capital costs of replacing the unit may prove to be financially prohibitive in the short run. Once again, the ECAR-MAIN-MARCA region is estimated to have the largest potential for pumped storage peaking capacity development as was the case under the generic retirement schedule. No pumped storage capacity development seems likely in the RMPA-NWPP region.

Several orders of dispatch were used in the pumped storage analysis to test the sensitivity of pumped storage peaking capacity development to changes in the relative economic efficiency of alternative fuel types. Pumped storage was dispatched after oil steam, coal steam, and other fuel types (all units dispatched before pumped storage are assumed to be more efficient and economical in generating electricity). The dispatching order for all other fuel types is listed below:

Hydro
Unsited base
Nuclear
Coal steam

Hydroelectric Pumped Storage Analysis
Pumped Storage Forecast For - Continental U S A. -

Generic Retirement Of Older Units

	Projection II			Median Projection			Dames & Moore Projection		
	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	96864.	98744.	86072.	96864.	98744.	86072.	96864	98744	86072.
1985	122817	126727.	83079.	145976	144073	97057.	111034.	116577.	72434.
1990	146279.	154362.	80602.	214168.	190839	113796.	118348.	134875.	53128.
1995	227551.	205522.	132474	331360.	258214	223534.	158936.	162286.	75275.
1999	323483.	254484.	226695.	392824	301868	340434.	208038.	188376.	115886
Pumped Storage Dispatched After Oil Steam									
1979	35888.	74180.	0.	35888	74180.	0.	35888.	74180.	0.
1985	48488	96942.	0.	59402	107004.	1524.	43706.	89067.	0.
1990	70463	123117.	194	113865	152299.	7670.	50046.	102925	0.
1995	168488.	180862	38682	297111.	250026.	108431.	79065.	129709	1324.
1999	288413	245545.	130607	385007.	301868.	242296.	149791	165484	33892.
Pumped Storage Dispatched Last									
1979	1924	7455.	0	1924.	7455.	0.	1924	7455	0
1985	6429.	23367.	0	11165	37274.	1561.	4773.	17914.	0.
1990	14632	49608.	8468.	42531.	88481	25289.	8196.	27005.	0.
1995	58232.	119162	51112	156671.	192837.	122598.	20415.	64517.	8856
1999	158938	195213.	138563.	232435.	248575.	250709.	66370.	116641.	41061.
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	96864.	98744.	86072	96864.	98744.	86072.	96864.	98744.	86072.
1985	99750	105979.	81948	115338	117365.	95471.	91925.	100882.	71174
1990	99404	113191.	77895	143662	138262	108958	82065.	97478.	47333.
1995	121530.	127305.	125294	206008	168255.	214986.	92902.	103876.	69258.
1999	171703	146200.	216299.	221333	178498.	328861.	109403.	107499.	107086.
Pumped Storage Dispatched After Oil Steam									
1979	35888	74180.	0	35888	74180	0.	35888.	74180.	0.
1985	38918	80806.	0	45182.	88496.	1330	36184.	77290	0.
1990	44691	89289	0.	67455	105555.	6225.	35834.	75648	0.
1995	82848	109064.	34137	176012	157988	100324.	40105.	80065.	857.
1999	148246.	138632.	120993	213105	178498	230753.	76249.	93796	30580.
Pumped Storage Dispatched Last									
1979	1924	7455.	0	1924.	7455	0	1924.	7455.	0.
1985	3102.	13130.	0	5715	20289	469.	2669	11787.	0
1990	4524	17073.	1933	15728.	37403	5754.	3417	13463.	0
1995	13150	43758	25126	71636	96414	84146.	5358	21361	0.
1999	52630	81564	106404	98527	122275	232176.	18964	41370.	19080

Table 5-10

Hydroelectric Pumped Storage Analysis
Pumped Storage Forecast For - NEPOOL - NYPP - MAAC -

Generic Retirement Of Older Units

	Projection II			Median Projection			Dames & Moore Projection		
	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	27459	21106	25573.	27459	21106	25573	27459	21106	25573
1985	33937	26132.	26817	35623.	27372	30157	30131.	23272	20136
1990	39741.	30663	30586	41088.	31619	33312	27268.	24259.	14525
1995	47681.	36792	43376	48782.	37537	45599	31708.	26879.	16750.
1999	55032	42464	59589	56471.	43440	62493.	33139.	28137	21346
Pumped Storage Dispatched After Oil Steam									
1979	6534.	12410.	0.	6534.	12410.	0.	6534.	12410	0
1985	8121	15355	0	10706.	17133.	0.	7193	13662	0
1990	14824.	21407	42	20751.	24167	2626.	6575.	14706	0
1995	45310	35920.	17254.	46681.	36808	19476.	13093	20184.	755.
1999	55032	42464.	37925	56471	43440	40828.	22789	23685.	5585.
Pumped Storage Dispatched Last									
1979	0.	0	0	0	0	0.	0.	0.	0.
1985	100	479.	0.	396.	1889	1301.	0	0.	0.
1990	1588.	7572.	2944.	2046	9755	6861.	6.	31.	0
1995	10159.	22443.	19571	10638	23105.	21380.	1324	6312.	1084.
1999	18504.	30076	37100.	19568.	31000	40062	5100	10608	3783.
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	27459.	21106.	25573	27459	21106.	25573.	27459	21106.	25573
1985	28531.	22176	26468	30021.	23280	29821	23382	20009.	19411.
1990	26871	23055	29390.	27947.	23825	32100.	16306	13656	9850.
1995	28025	24306.	41655	28804.	24838	43857.	18112	13823	13523
1999	28802.	25225.	57355.	29719.	25857.	60224	16831	12955	17171
Pumped Storage Dispatched After Oil Steam									
1979	6534.	12410	0	6534	12410	0.	6534	12410.	0
1985	6784.	13014.	0	8000	13942	0	5155.	11730	0.
1990	8214.	15180	0	12990	17232.	2477	3655.	7451	0
1995	25147	22904.	15381	26558	23771	17583	5396.	8973	562.
1999	28802	25225	35718	29719	25857.	38587.	11214.	10608	5137
Pumped Storage Dispatched Last									
1979	0	0	0	0	0	0.	0	0	0
1985	0	0	0	38	183	0	0	0	0
1990	365	1739	1933	462	2201	2105.	0	0	0
1995	2789	7957	7050	2757	7905	6861	216	1030	0.
1999	4566	10441	22967	4993	11380	28561	824.	3930	3273

Table 5-10 (cont'd)

Hydroelectric Pumped Storage Analysis
Pumped Storage Forecast For - Florida -

Generic Retirement Of Older Units

	Projection II			Median Projection			Dames & Moore Projection		
	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	11300	9196	9973	11300	9196	9973.	11300.	9196	9973
1985	17914	14289	11816	17914	14289	11816.	14160	11525.	9902
1990	22884	18228	13083	22884.	18228	13083.	16418	13361.	8543
1995	27982.	22287	19388	27982.	22287	19388	19035.	15490	12365.
1999	32867.	26176	25461	32867	26176.	25461	21427.	17435	15894.
Pumped Storage Dispatched After Oil Steam									
1979	2842.	5419	0	2842.	5419.	0.	2842.	5419.	0
1985	4505	8419.	0.	4505	8419	0.	3561.	6791.	0.
1990	7345	11372.	0.	7345.	11372	0.	4129.	7872	0
1995	25647.	21029.	5586.	25647	21029	5586	6222.	9660.	0.
1999	32867	26176.	13916.	32867	26176	13916.	18592.	15909.	4350.
Pumped Storage Dispatched Last									
1979	0	0.	0.	0.	0	0.	0	0.	0.
1985	322.	1561	0.	322.	1561.	0	0	0	0.
1990	1863	5817.	1953	1863.	5817.	1953.	0.	0.	0
1995	7291	14210.	8432.	7291.	14210	8432	884	4286.	79
1999	13820.	19734.	15558.	13820	19734	15558	4732	10759.	6341
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	11300.	9196	9973	11300.	9196.	9973.	11300	9196.	9973
1985	13588	11118	11573.	13588	11118	11573.	12489.	10219	9816.
1990	15287.	12628.	12670	15287.	12628.	12670.	12883	10643.	8366
1995	16751	13947	18778.	16751.	13947	18778	13386	11146	12076
1999	17977	15084.	24652	17977	15084.	24652	13767.	11553	15498.
Pumped Storage Dispatched After Oil Steam									
1979	2842.	5419	0	2842.	5419	0.	2842.	5419	0.
1985	3417.	6552.	0	3417	6552	0	3141	6022.	0
1990	3883	7490.	0	3883	7490	0.	3273.	6313	0.
1995	13745	12198	4976	13745	12198	4976	3400	6612.	0
1999	17977	15084	13108	17977	15084	13108	10682	9692	3954
Pumped Storage Dispatched Last									
1979	0	0	0	0	0	0	0	0	0
1985	0	0	0	0	0	0	0	0	0
1990	0	0	0	0	0	0	0	0	0
1995	1550	6514	2312	1550	6514	2312	0	0	0
1999	2904	8504	16231	2904	8504	16231	937	4542	1734

Table 5-10 (cont'd)

Hydroelectric Pumped Storage Analysis
Pumped Storage Forecast For - Southern - TVA - VACAR -

Generic Retirement Of Older Units

	Projection II			Median Projection			Dames & Moore Projection		
	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	8779.	13715.	0.	8779.	13715.	0.	8779.	13715.	0
1985	10127	18083	0	20674	23173.	2687.	9158	16875.	0.
1990	15400	23055	0	39493.	32694.	7055	12172.	19875.	0.
1995	31156	32026.	2352	68559	48350	26552.	15601.	23111.	0.
1999	62458.	44055	21194	85706.	56969.	48218.	17125.	24405.	0.
Pumped Storage Dispatched After Oil Steam									
1979	5934.	13630.	0.	5934.	13630	0.	5934.	13630.	0.
1985	8285.	18083.	0	14099.	21768.	1524.	7619.	16875.	0.
1990	11694.	22652.	0.	31235	30437.	2827.	9388.	19875.	0.
1995	23871.	29758.	1272.	67625.	47847.	23082.	12332.	22430.	0
1999	55031.	42031.	17659.	85706.	56969.	45151.	14270.	24069.	0.
Pumped Storage Dispatched Last									
1979	938.	2757.	0	938	2757	0.	938.	2757.	0.
1985	2436.	7567.	0.	4967.	12656.	260.	1970.	6358.	0.
1990	5155.	13575.	0.	20341	24129.	3222.	3808.	10396.	0.
1995	14077.	23530.	24.	51744	43012	20489.	5789.	14615.	0.
1999	43008	38213.	15688	73475	53677	42766.	7749	16830	0
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	8779	13715.	0	8779.	13715.	0.	8779.	13715.	0.
1985	7289.	15210.	0.	14363.	18394.	2228.	6928.	14507.	0.
1990	8906.	16669.	0	28734	24328	6359.	7644.	15203.	0.
1995	12089.	17676	1090	43243.	31092	24831.	7546.	15165.	0.
1999	30164	23102.	18957	50528	33370	45826.	7070.	14640.	0
Pumped Storage Dispatched After Oil Steam									
1979	5934	13630	0	5934	13630	0.	5934.	13630.	0
1985	6669	15210	0	9652	18112	1330	6308.	14507	0
1990	7455.	16669	0	19396	21687	2246.	6686	15203.	0.
1995	8927.	17656	796	42346	30589	21361	6705.	15165.	0
1999	24865	21078	15504	50528	33370	42758.	6426.	14640	0
Pumped Storage Dispatched Last									
1979	938	2757	0	938.	2757	0	938	2757	0.
1985	1222	4694	0	2862.	7877	469	987	3991	0
1990	2341	7190	0	10204	15093	2792	1750	5722	0
1995	3586	9180	422	28557	25371	18617.	2165	6669	0
1999	14569	16850.	13732	38754.	30269	40182.	2311.	7062	0

Table 5-10 (cont'd)

Hydroelectric Pumped Storage Analysis
Pumped Storage Forecast For - ECAR - MAIN - MARCA -

Generic Retirement Of Older Units

	Projection II			Median Projection			Dames & Moore Projection		
	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	13365.	24491	0.	13365	24491.	0	13365.	24491.	0.
1985	16022.	30033.	0.	22406	37442.	0.	14689	27831.	0.
1990	19752	36054	0.	47945.	55291.	6826	19045.	34385.	0
1995	58177.	58312.	12737	107109.	84723.	51527.	38256.	46878.	4438.
1999	96878	77412.	44695	124774	98434.	93542.	72237.	63638.	25253.
Pumped Storage Dispatched After Oil Steam									
1979	12219.	23398.	0	12219.	23398.	0.	12219.	23398.	0
1985	16022	30033	0	17680.	32961.	0.	14689.	27831.	0.
1990	18944.	35284.	0.	34568	49956.	1713.	17538.	32948.	0.
1995	44449.	53465.	6683	106964.	84640	45297.	30491	44163.	569.
1999	96683.	77353.	38484	124774.	98434	87329.	66208.	61421	18634.
Pumped Storage Dispatched Last									
1979	986.	4698	0.	986.	4698.	0.	986.	4698.	0.
1985	3571.	13760.	0	5480.	21168	0.	2803	11556.	0.
1990	5104.	18247.	0.	15912.	37483	2141.	4382.	16578.	0.
1995	22198	41328.	5814	75412.	75467	37992.	10444.	29894.	747.
1999	69442.	69655.	33488.	100305	91959.	82162.	42964.	53099	14974.
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	13365.	24491	0	13365.	24491.	0.	13365.	24491.	0.
1985	12801.	24712	0.	15614.	28504.	0.	12580.	24271.	0.
1990	13335	25952	0	25216	37058.	5509.	13145.	25548.	0.
1995	26351.	34027	10938	65686.	54497.	49095.	20910.	30644.	3557.
1999	51250.	44241.	42042.	68941.	57723.	90334.	35404.	35752.	23158.
Pumped Storage Dispatched After Oil Steam									
1979	12219.	23398	0	12219.	23398	0.	12219	23398.	0
1985	12801	24712.	0	14097	27058	0.	12580.	24271.	0
1990	13335	25952.	0	17305	31724.	1129.	13145.	25548.	0
1995	17054	29181.	5611	65563.	54413	42852.	15448.	28014	295
1999	51080	44182.	35815	68941.	57723.	84123	33917.	35460	16800.
Pumped Storage Dispatched Last									
1979	986	4698	0	986.	4698	0.	986	4698	0.
1985	1880	8436	0	2815	12229	0.	1682	7996	0
1990	1818	8144	0	4882	19250	0	1667	7741	0
1995	4582	17043	6323	35827	44991.	35818	2977	13662.	0
1999	28382	36154	32008	46179	51216	78752.	14729	25056.	9049.

Table 5-10 (cont'd)

Hydroelectric Pumped Storage Analysis
Pumped Storage Forecast For - SPP - ERCOT -

Generic Retirement Of Older Units

	Projection II			Median Projection			Dames & Moore Projection		
	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	25816	21016.	36819	25816	21016.	36819.	25816.	21016.	36819.
1985	33529.	27153.	31015	36566.	29624.	37702.	32989	26781	31259
1990	34562.	32756.	22214	46979	37955	36270	32348	31340.	20342
1995	44035	38626	34703	58189	46898.	57135.	40929	36251	30511
1999	54690	44034	49994.	68711	55285	80544.	48691.	39392	39816
Pumped Storage Dispatched After Oil Steam									
1979	6293	13368	0	6293	13368	0.	6293	13368.	0.
1985	8250	17017.	0	9021	18482	0.	8113.	16796.	0.
1990	10036.	20339	0	11664	23421	0.	9554.	19499	0.
1995	12131.	24037.	0	30748.	41283	3508.	11107.	22411	0.
1999	27242.	37178.	5008	60894	55285	33044.	13371.	25486.	0.
Pumped Storage Dispatched Last									
1979	0.	0.	0	0.	0	0.	0.	0	0.
1985	0	0	0.	0.	0.	0.	0	0.	0
1990	0	0.	0.	1318	6283.	6645	0	0	0.
1995	1752	8349.	8256	7633	25092	23019.	974	4645.	5558.
1999	7321	23273	19921.	16775.	35895.	49344.	3462.	16504.	11466.
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	25816.	21016.	36819.	25816	21016.	36819	25816	21016	36819
1985	28227.	23057	30624	30881.	25229	37282.	28366	23185	30916.
1990	25103	24399	21417.	34667.	28430	35363.	24486	23969.	19640.
1995	26435.	25280	33431.	37490	30892	55611.	25248.	24368.	29379
1999	31168.	25860.	48262.	39488.	32700	78394	28516	23743	38325.
Pumped Storage Dispatched After Oil Steam									
1979	6293.	13368	0	6293.	13368	0	6293	13368	0
1985	6904.	14588	0	7578	15876	0	6939	14664	0
1990	7291	15384	0	8539	17774	0	7146.	15129.	0.
1995	7518	15906	0	15055	24028	2588	7220.	15366	0
1999	13180	20375	3964	31260	32700	30893.	6978	14995	0
Pumped Storage Dispatched Last									
1979	0	0	0	0	0	0.	0	0	0
1985	0	0	0	0	0	0	0	0	0
1990	0	0	0	0	0	0	0	0	0
1995	0	0	0.	1241	5918	8786	0	0	0
1999	594	2834	5529	2805	12166	48660	74	354	5024

Hydroelectric Pumped Storage Analysis
Pumped Storage Forecast For - RMPA - NWPP -

Generic Retirement Of Older Units

	Projection II			Median Projection			Dames & Moore Projection		
	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)	Pumped Storage (GWH)	Pumped Storage (MW)	Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	0.	0.	0.	0	0	0.	0.	0	0.
1985	0	0.	0	0.	0	0	0.	0	0
1990	0.	0	0	0	0.	0	0	0	0.
1995	0.	0	0.	0.	0	0	0.	0.	0
1999	0.	0.	0	0	0	0.	0.	0.	0
Pumped Storage Dispatched After Oil Steam									
1979	0.	0	0	0	0.	0.	0.	0	0.
1985	0.	0	0	0.	0	0.	0.	0	0
1990	0	0.	0.	0	0	0.	0.	0	0
1995	0.	0.	0	0	0	0.	0.	0	0.
1999	0	0	0	0	0.	0.	0	0.	0
Pumped Storage Dispatched Last									
1979	0	0.	0.	0	0	0.	0	0.	0.
1985	0.	0.	0	0	0.	0.	0	0.	0.
1990	0	0.	0.	0	0.	0.	0	0.	0.
1995	0	0	0	0	0	0.	0.	0.	0.
1999	0.	0.	0	0	0.	0.	0	0.	0.
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	0.	0.	0	0	0	0.	0	0.	0.
1985	0	0.	0	0.	0	0.	0.	0	0.
1990	0	0	0	0	0.	0.	0.	0.	0
1995	0.	0.	0.	0.	0	0.	0	0.	0.
1999	0	0	0.	0	0	0.	0	0	0
Pumped Storage Dispatched After Oil Steam									
1979	0	0	0	0.	0	0.	0.	0	0.
1985	0.	0	0	0	0	0.	0	0	0.
1990	0	0	0	0	0.	0.	0	0	0.
1995	0	0	0	0	0.	0.	0	0	0
1999	0	0	0	0.	0	0.	0.	0	0
Pumped Storage Dispatched Last									
1979	0	0	0	0	0	0	0.	0.	0
1985	0	0	0	0	0.	0	0	0.	0
1990	0	0	0.	0.	0	0.	0	0.	0
1995	0	0	0	0.	0	0.	0	0	0.
1999	0	0	0.	0.	0	0.	0	0	0

Table 5-10 (cont'd)

Hydroelectric Pumped Storage Analysis
Pumped Storage Forecast For - AZNM - SCNV - NCNV -

Generic Retirement Of Older Units

	Projection II Pumped Storage (GWH)	Projection II Pumped Storage (MW)	Projection II Unsited Base (MW)	Median Projection Pumped Storage (GWH)	Median Projection Pumped Storage (MW)	Median Projection Unsited Base (MW)	Dames & Moore Projection Pumped Storage (GWH)	Dames & Moore Projection Pumped Storage (MW)	Dames & Moore Projection Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	10145	9220.	13707	10145.	9220.	13707.	10145.	9220.	13707.
1985	11288.	11037.	13431	12793	12173.	14695.	9907.	10293.	11137
1990	13940.	13606	14719	15779.	15052.	17250.	11097.	11655	9718
1995	18520	17479.	19918	20739	18419.	23333.	13407.	13677.	11211.
1999	21558.	20343	25762	24295.	21564.	30176.	15419.	15369.	13577.
Pumped Storage Dispatched After Oil Steam									
1979	2066.	5955.	0	2066	5955	0.	2066.	5955.	0.
1985	3305.	8035.	0	3391	8241	0.	2531.	7112.	0.
1990	7620	12063.	152.	8302	12946.	504.	2862.	8025.	0.
1995	17080	16653.	7887	19446	18419	11482.	5820.	10861.	0.
1999	21558.	20343.	17615	24295.	21564.	22028.	14561	14914.	5323.
Pumped Storage Dispatched Last									
1979	0.	0.	0	0.	0	0.	0.	0.	0
1985	0.	0.	0.	0.	0	0.	0.	0	0.
1990	922.	4397.	3571.	1051.	5014.	4467.	0.	0.	0.
1995	2755	9302	9015	3953.	11951.	11286.	1000.	4765	1388.
1999	6843	14262.	16808.	8492	16310.	20817.	2363.	8841.	4497.
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	10145	9220.	13707	10145.	9220.	13707.	10145.	9220.	13707.
1985	9314	9706	13283.	10871	10840	14567.	8180.	8691	11031.
1990	9902	10488.	14418.	11811.	11993	16957.	7601	8459.	9477.
1995	11879	12069	19402	14034.	12989.	22814.	7700.	8730.	10723.
1999	12342	12688.	25031.	14680.	13764.	29431.	7815.	8856.	12934.
Pumped Storage Dispatched After Oil Steam									
1979	2066.	5955	0.	2066.	5955	0.	2066	5955	0
1985	2343	6730	0	2438.	6956	0.	2061.	6096.	0
1990	4513	8614.	0.	5342	9648	373.	1929.	6004	0
1995	10457	11219.	7373	12745.	12989	10964	1936.	5935.	0
1999	12342	12688.	16884	14680	13764.	21284	7032.	8401	4689
Pumped Storage Dispatched Last									
1979	0	0	0	0	0.	0.	0	0	0.
1985	0	0	0	0	0	0.	0.	0	0
1990	0	0	0	180	859	857	0	0	0.
1995	643	3064	9019	1704	5715	11752.	0	0.	0
1999	1615	6781	15937	2892	8740	19790.	89	426	0

Table 5-10 (cont'd)

Gas steam

Oil steam

Gas combined-cycle

Oil combined-cycle

Gas turbine

Oil turbine

Other (all new technological innovations for meeting peaking capacity, e.g., solar, windpower, etc.)

The Dames & Moore DISPATCH program assumes that any particular generating unit is in operation at least 5 percent of the year, ensuring that no generating unit is left idle in any year. Coal-burning units are used to pump the water under the after-coal-steam and after-all-other-fuels dispatches. Oil-burning units are used to pump the water under the after-oil-steam dispatch.

The dispatching order of pumped storage has a significant effect on the estimated potential for pumped storage development. Dispatching pumped storage after coal steam produced the largest estimate of pumped storage development, while potential pumped storage development is lowest when it is dispatched after all other fuel types. By dispatching pumped storage after coal steam, a fuel high in the dispatch order, it is assumed that pumped storage is less expensive than all other fuel types below it on the list. Consequently, there will be more potential for pumped storage peaking capacity development since it is a less expensive fuel source. When pumped storage is dispatched after all other fuel types, the algorithm assumes it is the most expensive form of peaking capacity; hence, within the scenario there would be little reason to build pumped storage facilities. However, although pumped storage is one of the least expensive sources of generating peaking capacity in the long run, any type of major capital investment will be cost-prohibitive in the short run. Considering the current issues facing utilities in the financial markets, using existing units, although with much more expensive fuel sources than hydro, may prove less expensive at the present time. And the after-all-other-fuel-sources position is the most likely dispatch order for pumped storage under the present economic situation.

The ECAR-MAIN-MARCA region consistently displayed the largest potential for pumped storage development, followed by the Southern-TVA-VACAR region. No potential pumped storage or unsited base capacity development is projected for the RMPA-NWPP region, regardless of dispatch order. The ECAR-MAIN-MARCA region also showed the greatest potential for unsited base capacity development when pumped storage was dispatched after coal and oil steam. However, in the Southern-TVA-VACAR region, the unsited base development estimates are greater when pumped storage was dispatched after all other fuel types.

The effect of load management in altering the future needs for pumped storage capacity development was examined in the pumped storage analysis. Load factors were developed from the initial pumped storage results, and the load factor was increased by .5 percent for each year during the forecast period. This technique resulted in a load management impact of 10 percentage points in the year 1999. (The estimate of the effects of load management on the need for pumped storage specifically was obtained from a recent DOE study on load management.)

Load management reduces the potential for pumped storage capacity development. If peak demand is reduced by load management techniques, the potential for pumped storage development--a peaking technology--will be lessened. To predict its effect, load management was implemented in the computer program on the same set of conditions described in our discussion thus far. The magnitude of the reduction in estimated pumped storage ranged from 71 percent (Dames & Moore load growth projection, generic retirement schedule, pumped storage dispatched last) to 41 percent in three of six dispatches under the median load growth projection (Tables 5-7 and 5-10). The potential for pumped storage capacity development remains the greatest in the ECAR-MAIN-MARCA region, followed by the Southern-TVA-VACAR region.

Peaking capacity development and maximum supportable peaking energy were projected for each of the seven composite regions in the United States and are presented in Table 5-11 (utility-announced retirement schedule) and Table 5-12 (generic retirement schedule). Peaking capacity development represents the capacity needed to meet future peak loads through new technological sources other than pumped storage. No attempt was made to incorporate physical or geographical limitations to peaking capacity development in the algorithm. Unsited base capacity development was calculated in accordance with alternative peaking capacity (unsited base represents the amount of additional capacity needed to meet the base load, in addition to that needed for peaking).

Hydroelectric Pumped Storage Analysis
Peaking Capacity Forecast For - Continental U.S.A. -

Utility Announced Retirements Only

	Projection II			Median Projection			Dames & Moore Projection		
	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	700	384.	10038.	700.	384.	10038.	700	384.	10038.
1985	6155	4406	19840	9476	7474	30950.	4564.	2994.	13894.
1990	9803	7687.	30366	17248.	13620	69618.	7998	5864.	18337.
1995	17452.	14152	99561	35361.	29382.	203342.	11575.	8827	30185
1999	29118.	23972.	195652	49417	42012	339742.	15084.	11867.	56681.
Pumped Storage Dispatched After Oil Steam									
1979	18013.	16951	0.	18013	16951.	0.	18013.	16951.	0.
1985	34554	30547.	1890	40646.	36436	5899.	28525.	25197.	693
1990	43895.	38590.	5316	56277.	50334.	27657.	34892	30469.	693
1995	63228.	55496.	46806	84592.	76958	129123.	42280	36678.	5191.
1999	85738	76954.	122978.	111095.	102119	250403	51332.	44747.	22228.
Pumped Storage Dispatched Last									
1979	700.	384.	8810	700.	384.	8810.	700.	384.	8810.
1985	2508.	1646.	13060.	4008.	2696	22612.	2380.	1552.	9362
1990	3613.	2531.	19901.	6955.	4826	62301.	3828.	2713.	13807.
1995	7671.	5563.	82053	28003.	16602	177554.	5672	4074.	25838.
1999	16975.	11212.	174243.	39841.	25717.	312865.	9363.	6583.	48476.
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	700.	384.	10038.	700.	384.	10038.	700	384	10038.
1985	1414	970.	14509	4177.	2830.	19793.	1614	1054	21459.
1990	2038.	1398.	25412.	5695	4129.	41711.	2217	1501.	21459.
1995	2393.	1703	51244	9963.	5576	134111	2455.	1686	27643.
1999	7682.	2923	113291	14914.	6625	241709	4910.	1834.	42198.
Pumped Storage Dispatched After Oil Steam									
1979	18013	16951.	0	18013.	16951	0.	18013	16951	0
1985	21773.	19260	1464.	26769.	23766	4558.	21290.	19018	561.
1990	23564.	20599	3398	30482	26666	13888.	21801.	19479	561.
1995	26940	21686.	20453	54932	33003	80265.	22505.	19736	854.
1999	40857.	24958	65111	67614	37317	175909	25140	20324.	10711.
Pumped Storage Dispatched Last									
1979	700	384.	8810	700	384	8810.	700	384	8810
1985	1136	660	10488	1896.	1192	14261.	1496	706	17730
1990	1506	920	21162.	2730	1840	34871	2099	1353	17730
1995	1741	1091	42441	4748	2998	121941	2337	1538	20517
1999	3356	1538	98737	11084	3867	229388	4792	1686	31604

Table 5-11

Hydroelectric Pumped Storage Analysis
Peaking Capacity Forecast For - NEPOOL - NYPP - MAAC -

Utility Announced Retirements Only

	Projection II			Median Projection			Dames & Moore Projection		
	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	0.	0.	0.	0.	0	0	0.	0.	0.
1985	0.	0.	0.	0.	0.	823	0.	0.	0.
1990	0	0	2344.	0	0	5378.	0.	0.	4445.
1995	0.	0.	18172.	0.	0.	20877.	0.	0.	5315
1999	0.	0.	36311.	0.	0	39788.	0.	0.	7412
Pumped Storage Dispatched After Oil Steam									
1979	0	0.	0.	0.	0.	0.	0.	0.	0.
1985	0.	0	0	0.	0	0.	0.	0.	0
1990	0	0.	0.	0	0.	529.	0.	0	0
1995	2005	1215	10013	1841.	1120.	12428.	0.	0	0.
1999	6417	4737	24056.	6354.	4686.	27385.	0.	0.	799.
Pumped Storage Dispatched Last									
1979	0	0.	0.	0	0.	0.	0.	0.	0
1985	0	0.	0.	0.	0	817.	0	0.	0.
1990	0.	0	0	0.	0.	2378.	0.	0.	4445
1995	0	0.	9881.	0	0.	11737.	0	0.	4445.
1999	0	0	25074	0	0.	27547.	0.	0.	4445.
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	0.	0.	0	0.	0	0.	0	0.	0
1985	0	0.	0	0	0.	0.	0	0	8678.
1990	0	0.	9363	0	0.	9916.	0.	0.	8678.
1995	0	0	16740	0	0	19237.	0.	0	11783.
1999	0	0	29751	0	0	32947	0	0.	15287
Pumped Storage Dispatched After Oil Steam									
1979	0	0.	0	0	0	0.	0.	0.	0.
1985	0	0.	0	0	0	0	0.	0	0.
1990	0	0.	0	0	0	0	0.	0.	0
1995	0	0.	3877	0	0	4910	0.	0	0.
1999	0	0	12309	0	0	15583	0	0.	0
Pumped Storage Dispatched Last									
1979	0	0	0	0	0	0	0	0	0
1985	0	0	0	0	0	0	0	0	8678
1990	0	0	9134	0	0	9687	0	0	8678
1995	0	0	13771	0	0	16210	0	0	8678
1999	0	0	26933	0	0.	29921	0	0	8678

Hydroelectric Pumped Storage Analysis
Peaking Capacity Forecast For - Florida -

Utility Announced Retirements Only

	Projection II			Median Projection			Dames & Moore Projection		
	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	0	0	0	0	0.	0.	0.	0.	0.
1985	0	0	1664	0	0	1664.	0.	0.	0.
1990	0	0	5271	0.	0	5271.	0.	0.	0
1995	0.	0	14839.	0	0.	14839	0.	0.	1337.
1999	0	0	24005.	0.	0	24005.	0.	0.	6239.
Pumped Storage Dispatched After Oil Steam									
1979	378	402.	0	378.	402.	0.	378.	402.	0.
1985	3650	2591.	0.	3650.	2591.	0.	1662.	963.	0.
1990	6248	4801.	0.	6248	4801.	0	2911.	1935.	0.
1995	9615	7192	6299.	9615	7192	6299.	4450.	3189.	0.
1999	12120	9482.	12745.	12120.	9482.	12745.	6305.	4334.	1092
Pumped Storage Dispatched Last									
1979	0	0.	0.	0	0.	0.	0	0.	0.
1985	0	0.	1664	0.	0.	1664.	0.	0.	0.
1990	0	0	5271.	0	0.	5271.	0.	0.	0.
1995	0	0.	14839	0	0.	14839.	0.	0.	1337.
1999	0	0.	24005	0.	0	24005.	0.	0.	6239.
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	0.	0	0.	0.	0.	0.	0.	0.	0.
1985	0	0	0.	0.	0.	0.	0.	0.	0.
1990	0	0	0.	0.	0.	0.	0.	0.	0.
1995	0	0	4352	0	0	4352	0	0.	0.
1999	0.	0	10028	0	0	10028	0.	0	0.
Pumped Storage Dispatched After Oil Steam									
1979	378	402.	0.	378.	402	0	378.	402.	0.
1985	1277	724.	0	1277	724	0.	755.	402.	0
1990	2406	1552	0	2406.	1552.	0	757.	402.	0.
1995	4551.	2334	1580	4551	2334.	1580.	1173.	674	0.
1999	5832.	3008	6455	5832	3008.	6455.	1558.	915.	0.
Pumped Storage Dispatched Last									
1979	0	0	0.	0	0	0	0	0	0
1985	0	0	0	0	0.	0	0	0.	0
1990	0	0	0	0.	0	0	0.	0.	0
1995	0	0	4352.	0	0	4352.	0	0.	0.
1999	0	0	10028	0	0	10028	0.	0	0

Table 5-11 (cont'd)

Hydroelectric Pumped Storage Analysis
Peaking Capacity Forecast For – Southern – TVA – VACAR –

Utility Announced Retirements Only

	Projection II			Median Projection			Dames & Moore Projection		
	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	0	0.	0	0.	0	0.	0	0.	0.
1985	1221.	1241.	2401.	2615.	2807.	6542.	492.	439	2063.
1990	3156.	3255.	3621	4447.	4506.	16767	1504.	1515.	2063.
1995	4872.	5289.	11688	11331.	10639.	36398.	2133.	2177.	3477.
1999	9812.	9470	25982.	17183	15899.	55061.	2453.	2493	3477
Pumped Storage Dispatched After Oil Steam									
1979	2108.	2760.	0.	2108.	2760.	0.	2108.	2760.	0.
1985	5223	5033.	771	6630.	6529.	2136	4358.	4059.	540.
1990	7198	6969	771.	9444.	8993.	11377.	5291.	5058.	540.
1995	10002	9843.	6266.	15938.	15592	30516.	6139.	5720.	540.
1999	14663	14422.	20100.	21400.	20852.	49180.	7122.	6667.	540.
Pumped Storage Dispatched Last									
1979	0	0.	0.	0.	0.	0.	0.	0	0.
1985	0	0	0.	108	111	1929	0.	0.	0.
1990	0.	0.	0	607	.389.	16911.	0.	0.	0.
1995	1829.	1484	8539.	9256.	5191	32000.	0	0	0.
1999	5255	3507	24700.	13652	8781	52965.	0.	0	0
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	0.	0.	0	0	0	0	0.	0.	0.
1985	278.	310	1855	1121.	984	3095.	118.	148	1656.
1990	532	478.	1855	1664	1576.	9338	118.	148.	1656.
1995	652.	612.	1855	5010.	2600	24782.	118.	148.	1656
1999	5763	1697.	10736.	6961	2658	40756.	118.	148.	1656.
Pumped Storage Dispatched After Oil Steam									
1979	2108	2760.	0	2108	2760	0	2108.	2760.	0.
1985	3702	3445	656	4837.	4559	1097.	3513.	3307.	457
1990	3651	3536	656	5369	5074	4839.	3263.	3307.	457
1995	3842	3670	656	8863	6101	19963.	3261.	3307	457.
1999	9055	4755.	6580	12095	7415	34823	3238.	3307	457
Pumped Storage Dispatched Last									
1979	0	0	0	0	0	0	0	0	0
1985	0	0	0	0	0	0	0	0.	0
1990	0	0	0	0	0	4735	0	0.	0
1995	0	0	0	1081	735	21544	0	0	0
1999	1437	312	6992	5426	1288	38780	0	0.	0

Table 5-11 (cont'd)

Hydroelectric Pumped Storage Analysis
Peaking Capacity Forecast For - ECAR - MAIN - MARCA -

Utility Announced Retirements Only

	Projection II			Median Projection			Dames & Moore Projection		
	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	700.	384	1228.	700.	384.	1228.	700.	384.	1228.
1985	4934	3165	2737	6861.	4667	5763.	4072.	2555	2469.
1990	6647	4432.	2737	12801	9114	16305	6494.	4349	2469
1995	12580	8863	17291	24030	18743	56418.	9442.	6650.	10180
1999	19306.	14502	41288	32234.	26113	91832.	12631.	9374.	20912.
Pumped Storage Dispatched After Oil Steam									
1979	6119.	5018.	0	6119.	5018	0.	6119.	5018.	0.
1985	12899	10707.	0.	16158	13635	0	10304.	8504	0.
1990	14510	11888	0.	21649	18525	4899	12520.	10213.	0.
1995	21428.	18132.	5854	32201	29001.	44237.	15249.	12521.	4346.
1999	28086	24760	29107	39769	36370	79650.	19643.	16636	15078.
Pumped Storage Dispatched Last									
1979	700.	384	0	700	384	0.	700	384.	0.
1985	2508	1646.	0	3900	2585.	3686.	2380	1552	0.
1990	3613	2531	0	6348	4437	14860.	3828	2713	0
1995	5842	4079.	14789	18747	11411	50760.	5672	4074	10180.
1999	11720.	7705	38333.	26189	16936	86734.	9363	.6583	20912.
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	700	384	1228	700.	384	1228	700	384	1228.
1985	1136.	660	2119	3056.	1846	3083	1496	906.	2073.
1990	1506	920	2119	4031.	2553	3641	2099.	1353.	2073.
1995	1741	1091	3164	4953	2976	38664.	2337	1538	4298.
1999	1919	1226	19806	7953.	3967	67924.	4792.	1686	11738
Pumped Storage Dispatched After Oil Steam									
1979	6119	5018	0.	6119.	5018	0.	6119	5018	0
1985	6755	5567	0	9396.	7731	0.	7046.	5770	0
1990	7075	5742	0	10238.	8353	0	7647	6132	0
1995	7352	5913	0	27612	12309	26964	7909	6317	0
1999	13921	7411	10648	33945	13454	56208	10359	6464	6047
Pumped Storage Dispatched Last									
1979	700	384	0	700	384	0	700	384	0
1985	1136	660	0	1896	1192	693	1496	706	0
1990	1506	920	0	2730	1840	1687	2099	1353.	0
1995	1741	1091	99	3667	2263	35027	2337	1538	2133
1999	1919	1226	12985	5658	2579	63109	4792	1686	9409.

Table 5-11 (cont'd)

Hydroelectric Pumped Storage Analysis
Peaking Capacity Forecast For - SPP - ERCOT -

Utility Announced Retirements Only

	Projection II			Median Projection			Dames & Moore Projection		
	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	0	0.	0	0	0	0.	0.	0.	0.
1985	0.	0.	0	0	0	0	0	0.	0.
1990	0.	0.	0	0.	0	2649.	0.	0.	0.
1995	0.	0.	5586.	0	0	29211.	0.	0.	0.
1999	0.	0.	19053.	0	0	59175.	0.	0.	4586
Pumped Storage Dispatched After Oil Steam									
1979	9112.	8380	0.	9112.	8380	0.	9112.	8380.	0
1985	12154	11501	0.	13580.	12966	0.	11940.	11280.	0.
1990	14611.	13534	0.	17608.	16617.	0.	13883.	12872.	0.
1995	17527.	16265	0	22292	21170	4310.	16145.	14857.	0.
1999	20652.	19470.	2913	27223.	26348.	27541.	17960.	16719.	0.
Pumped Storage Dispatched Last									
1979	0	0.	0.	0.	0	0.	0.	0.	0.
1985	0.	0.	0	0	0.	0.	0.	0.	0.
1990	0	0.	0	0.	0.	1396.	0.	0	0
1995	0.	0	5586.	0	0.	27239.	0.	0.	0.
1999	0	0	17624.	0	0.	57214.	0	0.	3104.
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	0	0	0	0.	0.	0.	0.	0.	0
1985	0	0.	0	0.	0	0	0.	0.	0
1990	0	0.	0.	0.	0	0.	0	0.	0.
1995	0	0	0	0.	0.	8805.	0.	0	0
1999	0	0.	3004	0	0	30393.	0	0	0
Pumped Storage Dispatched After Oil Steam									
1979	9112	8380	0.	9112.	8380	0.	9112.	8380	0
1985	9779.	9133	0	10999.	10361	0	9813.	9148.	0.
1990	10148	9378	0	12185.	11296	0	9971.	9247	0.
1995	10282	9378	0	12993	11868	0	9999.	9247.	0
1999	10349	9378	0	14042	13034	14533	9822	9247.	0.
Pumped Storage Dispatched Last									
1979	0	0	0	0	0	0	0	0	0
1985	0	0	0	0	0	0	0	0	0
1990	0	0	0	0	0	0	0	0	0.
1995	0	0	0	0.	0	8264	0	0	0
1999	0	0	3004.	0	0.	27880	0	0	0

Hydroelectric Pumped Storage Analysis
Peaking Capacity Forecast For - RMPA - NWPP -

Utility Announced Retirements Only

	Projection II			Median Projection			Dames & Moore Projection		
	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	0	0	0	0	0.	D.	0.	0	0.
1985	0.	0	54	0	0	3174.	0.	0	0.
1990	0	0.	54	0.	D.	6909	0.	0.	0.
1995	0	0.	6589	0	0.	17581.	0.	0	514.
1999	0	0.	13336	0	0	28949	0.	0	4294.
Pumped Storage Dispatched After Oil Steam									
1979	0.	0	0.	0.	0.	0.	0.	0.	0.
1985	0.	0.	0.	D.	0	2644.	D.	0.	0.
1990	0.	0	0.	0	0	6307.	0.	0	0.
1995	0.	0.	6228	0.	0.	16947.	0	0.	152.
1999	0	0.	12974	0	0.	28466.	0.	0.	3933.
Pumped Storage Dispatched Last									
1979	0.	0	0	0.	0	0.	0.	0.	0.
1985	0.	0	54	0	0.	3174.	0.	0	0.
1990	0.	0	54	0	0.	6909.	0.	0	0
1995	0	0.	6589.	0.	0.	17575.	0.	0	514.
1999	0.	0.	13336.	0.	0	28905	0.	0	4294.
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	0	0.	0	0.	0	0.	0	0	0.
1985	0	0.	103.	0	0	3183.	0.	0.	0.
1990	0.	0.	103	0	0	6844.	0.	0.	0.
1995	0.	0	6671.	0.	0	17579	0.	0.	654.
1999	0.	0.	13431	0.	0.	28935.	0.	0.	4465.
Pumped Storage Dispatched After Oil Steam									
1979	0	0.	0.	0	0.	0	0	0	0
1985	0.	0.	0	0	0	2653	0.	0.	0
1990	0	0.	0	0	0	6307.	0.	0.	0.
1995	0.	0.	6309	0.	0	16946	0	0	293.
1999	0.	0	13070	0	0	28452	0.	0.	4103
Pumped Storage Dispatched Last									
1979	0	0	0	0	0	0.	0	0	0
1985	0	0	103	0	0	3183	0	0	0
1990	0	0	103	0	0	6837	0	0	0
1995	0	0	6671	0	0	17579	0	0.	654
1999	0	0	13431	0	0	28935.	0	0	4465

Table 5-11 (cont'd)

Hydroelectric Pumped Storage Analysis
Peaking Capacity Forecast For - AZNM - SCNV - NCNV -

Utility Announced Retirements Only

	Projection II			Median Projection			Dames & Moore Projection		
	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	0.	0	8810	0	0	8810.	0.	0.	8810.
1985	0.	0	12984	0.	0	12984.	0	0.	9362.
1990	0.	0	16339	0.	0	16339	0	0	9362
1995	0.	0.	25396.	0.	0	28018	0.	0	9362.
1999	0	0	35677	0.	0	40932	0.	0.	9761
Pumped Storage Dispatched After Oil Steam									
1979	296.	391	0	296.	391	0.	296.	391.	0.
1985	628.	715	1119	628.	715.	1119.	261.	391.	153.
1990	1328.	1398	4545	1328	1398.	4545	287.	391.	153
1995	2651.	2849.	12146.	2705.	2883.	14386	297	391.	153.
1999	3800	4083.	21083	4229.	4381	25436.	302	391	786.
Pumped Storage Dispatched Last									
1979	0.	0.	8810.	0	0	8810.	0.	0	8810.
1985	0.	0	11342.	0	0.	11342	0	0.	9362
1990	0.	0	14576	0	0.	14576.	0	0.	9362.
1995	0.	0	21830	0.	0.	23404.	0	0.	9362.
1999	0.	0	31171.	0.	0.	35495.	0	0	9482.
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	0.	0	8810.	0.	0	8810	0.	0	8810.
1985	0.	0	10432	0.	0	10432	0	0.	9052.
1990	0	0.	11972	0.	0	11972	0	0.	9052.
1995	0.	0	18462	0.	0	20692	0	0.	9052
1999	0	0	26535	0.	0	30726	0.	0.	9052.
Pumped Storage Dispatched After Oil Steam									
1979	296.	391	0	296.	391.	0	296	391.	0.
1985	260.	391.	808	260.	391	808	163	391.	104.
1990	284	391	2742	284	391	2742	163.	391	104
1995	913	391	8031	913	391	9902	163.	391.	104
1999	1700	406	16049	1700.	406	19855.	163	391.	104
Pumped Storage Dispatched Last									
1979	0	0	8810	0	0	8810	0	0	8810
1985	0.	0	10385	0	0	10385	0	0	9052
1990	0	0	11925	0	0	11925	0	0	9052
1995	0	0	17548	0	0	18965	0	0	9052
1999	0.	0	25364	0	0	28735	0	0	9052

Table 5-11 (cont'd)

Hydroelectric Pumped Storage Analysis
Peaking Capacity Forecast For - Continental U S A. -

Generic Retirement Of Older Units

	Projection II			Median Projection			Dames & Moore Projection		
	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	700	384	10038	700.	384.	10038.	700.	384.	10038
1985	8329	6299.	21585	12567.	10021.	35896.	6863	4887.	14832.
1990	12536.	10223.	43139.	22945	19060	89048	10771.	8401.	19929.
1995	26253	22459	135849.	43150	38182	247305.	14483	11768.	52250.
1999	41799	38046	267398	60292	55814.	411655.	26230.	22812.	115157.
Pumped Storage Dispatched After Oil Steam									
1979	18013	16951.	0.	18013.	16951.	0.	18013.	16951.	0.
1985	35791	32049.	3365.	41840.	37922.	8361.	29122.	25872.	894.
1990	45253	39710	14622.	58473	52522	47639.	35582.	31272.	2110.
1995	69763.	62286.	85543	90289.	82948.	182315.	44134	38422.	21792.
1999	94093	87675.	200175	119312.	113000.	335805.	60361	55049.	65465
Pumped Storage Dispatched Last									
1979	700.	384.	8810	700	384.	8810.	700	384.	8810.
1985	3113	2204	15261	6748	4623.	25227	2989.	2110	9617.
1990	5343.	3834.	26938.	12022	8078.	73428	5358.	3928	16146.
1995	18539.	11655.	114279	35594.	25115	226137.	9268.	6783	40771
1999	41279	26349	239505.	54879.	41911.	392937.	19766.	14529.	98973
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	700	384.	10038	700.	384	10038	700.	384	10038
1985	3944	2659	16378.	6570	4723.	22105	3924.	2620	22466.
1990	4994.	3531.	30632	8746	6647.	55170.	4985.	3493.	22466
1995	5563	4060	78649.	27481.	11756.	176022	5425	3904	32891.
1999	21532	8497.	182055	43487.	18824	314510.	9656	5606.	60122.
Pumped Storage Dispatched After Oil Steam									
1979	18013.	16951	0	18013	16951	0.	18013	16951	0.
1985	22322	19826.	2239	27402	24440	5564.	21846.	19630	763
1990	24369.	21275.	7600	33276.	27466.	22440.	22762.	20186	1529
1995	29058	22766	45011	59858	35829	127878.	24545.	20978.	5650.
1999	59010	31167	139966	84013	45540.	264404	29265.	22904	33023
Pumped Storage Dispatched Last									
1979	700	384.	8810	700	384	8810	700	384.	8810.
1985	1858	1217	10892	2536	1750	16327.	2175	1463	18028.
1990	2451	1733	23419	3570	2665.	43744	2975	2165	18028
1995	2874	2128	64168	12707	5085.	158740.	3400	2576	23265.
1999	12884	5182	168240	30527	11509.	296255	7085	3582	51011

Table 5-12

Hydroelectric Pumped Storage Analysis
Peaking Capacity Forecast For - NEPOOL - NYPP - MAAC -

Generic Retirement Of Older Units

	Projection II			Median Projection			Dames & Moore Projection		
	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	0	0	0.	0.	0	0.	0.	0.	0.
1985	0	0	0.	0.	0	3111.	0.	0.	0.
1990	0	0.	9915	0	0.	13218.	0.	0	4590.
1995	0.	0.	33187	0	0	35777.	0.	0	10528
1999	0	0.	56063	0.	0.	59501.	0.	0.	16008.
Pumped Storage Dispatched After Oil Steam									
1979	0	0	0	0.	0.	0.	0.	0.	0.
1985	0.	0.	0	0.	0.	0.	0.	0.	0.
1990	0	0	3013.	0.	0.	6253.	0.	0.	0.
1995	4935.	3785.	22907	4813.	3688.	25509.	0.	0.	4354.
1999	9008.	7336.	43220.	9291.	7711.	46240.	266.	141.	8579.
Pumped Storage Dispatched Last									
1979	0.	0	0.	0.	0	0.	0,	0.	0.
1985	0	0.	0	0.	0.	1570.	0.	0.	0.
1990	0.	0.	2703	0.	0	5939.	0.	0.	4590.
1995	0.	0.	23762	0	0.	25861.	0.	0.	6886.
1999	0	0.	45304	0	0.	50468.	0.	0.	10227.
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	0.	0.	0.	0.	0	0.	0.	0.	0.
1985	0.	0.	0.	0.	0	635.	0.	0.	8748.
1990	0.	0.	11494	0.	0	14770.	0.	0.	8748.
1995	0.	0.	27185.	0.	0	29641.	0.	0.	15353.
1999	0.	0.	45519	0.	0	48660.	0	0.	15353.
Pumped Storage Dispatched After Oil Steam									
1979	0.	0.	0	0.	0.	0.	0.	0.	0.
1985	0.	0.	0	0	0.	0.	0.	0.	0.
1990	0.	0	0.	0.	0	1683.	0.	0.	0.
1995	0	0.	14383.	0.	0.	16678.	0.	0.	0
1999	2333.	423.	34035	2333	423	37028.	0.	0.	2551.
Pumped Storage Dispatched Last									
1979	0	0	0	0.	0	0.	0	0	0
1985	0	0	0	0	0.	635.	0.	0.	8748.
1990	0	0	9989	0.	0	12664.	0	0	8748.
1995	0.	0	22555	0	0	25248.	0.	0.	8748.
1999	0	0	41116	0	0.	44110.	0	0	9555.

Hydroelectric Pumped Storage Analysis
Peaking Capacity Forecast For - Florida -

Generic Retirement Of Older Units

	Projection II			Median Projection			Dames & Moore Projection		
	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	0.	0	0	0	0	0.	0.	0	0.
1985	0.	0.	1854	0	0	1854.	0.	0.	0.
1990	0.	0	6907.	0	0	6907	0.	0.	0.
1995	0	0.	18590	0.	0.	18590.	0.	0.	5089.
1999	576.	598.	29832	576	598	29832.	0.	0.	12776
Pumped Storage Dispatched After Oil Steam									
1979	378.	402.	0	378.	402	0	378.	402.	0.
1985	3665	2605	0.	3665.	2605	0	1681.	977.	0.
1990	6748	4891.	1100.	6748.	4891	1100	2997.	2024.	0.
1995	10017	7472	9717	10017.	7472.	9717.	5139.	3469.	970.
1999	12748.	9999.	18669	12748	9999	18669.	6998.	4851.	7016.
Pumped Storage Dispatched Last									
1979	0	0.	0.	0.	0.	0	0.	0.	0.
1985	0.	0.	1854.	0.	0.	1854.	0.	0.	0.
1990	0.	0.	6907	0	0.	6907	0.	0.	0.
1995	0.	0	18590.	0.	0	18590.	0.	0.	5089.
1999	576.	598.	29832.	576.	598.	29832.	0.	0.	12776.
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	0.	0.	0	0.	0	0.	0	0.	0.
1985	0.	0.	0	0.	0	0	0.	0	0.
1990	0.	0	0.	0.	0	0.	0.	0	0.
1995	0.	0	8103	0.	0	8103.	0.	0.	0.
1999	0.	0.	16565	0.	0	16565.	0.	0.	5394.
Pumped Storage Dispatched After Oil Steam									
1979	378.	402	0	378	402	0	378.	402.	0.
1985	1298	738.	0	1298	738	0.	755.	402.	0.
1990	2498.	1642	0	2498	1642	0	813.	465.	0.
1995	4951.	2615	4998.	4951	2615	4998.	1573.	954	0
1999	6345.	3525	12379	6345	3525	12379.	2841.	1432.	3694
Pumped Storage Dispatched Last									
1979	0	0	0	0	0	0	0.	0	0.
1985	0	0	0	0	0	0	0	0.	0
1990	0	0	0	0	0	0	0.	0	0
1995	0	0	8103	0	0	8103	0	0	0
1999	0	0	16565	0.	0	16565	0	0	5394.

Table 5-12 (cont'd)

Hydroelectric Pumped Storage Analysis
Peaking Capacity Forecast For - ECAR - MAIN - MARCA -

Generic Retirement Of Older Units

	Projection II			Median Projection			Dames & Moore Projection		
	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	700.	384	1228	700	384	1228.	700.	384	1228.
1985	6897	4900.	2907.	9774	7057	6540.	6144.	4290	2795
1990	9124.	6730	2907	17780.	14008	17595.	9007.	6647.	2795
1995	19192	15459.	20956	29442.	25134.	60869.	12083.	9352.	11778.
1999	27834.	24324	52589	39381	35711.	103132.	21682.	18552	32370
Pumped Storage Dispatched After Oil Steam									
1979	6119.	5018	0	6119.	5018	0.	6119.	5018	0
1985	13350.	11200	0	16584.	14129	-0.	10762.	8799	0
1990	14977.	12423.	0.	22814.	19966	10766.	12986	10747	0.
1995	23482.	20672	14899	33113.	30340	54707.	15959	13350	8386.
1999	31266.	29487	46457	42507	40875	97000	25459.	23716.	26238.
Pumped Storage Dispatched Last									
1979	700.	384.	0	700.	384	0	700	384.	0.
1985	3113.	2204.	454	6640.	4512.	3785.	2989	2110.	67.
1990	5343	3834	454	11385.	7741.	14229.	5358	3928.	2006.
1995	14803	9219	16455	26208.	18815.	60869.	9268	6783	11778.
1999	25477	16461	47275.	38277.	30171	103132	19766.	14529	32370
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979.	700	384.	1228	700.	384.	1228	700	384	1228.
1985	3442	2192.	2590	5250.	3581.	3350.	3806	2472.	2544
1990	4197.	2815	2590	6832	4833.	8152	4867	3345.	2544
1995	4641.	3210	7816	21639	8497.	43689.	5307.	3756.	5627
1999	15283.	6254	33729.	33038	12944	79689.	9538	5458.	16415.
Pumped Storage Dispatched After Oil Steam									
1979	6119	5018.	0	6119	5018	0.	6119	5018.	0
1985	7200	6013	0	9868.	8225	0	7478	6216	0
1990	7531	6207	0	12617	8882	595.	8084.	6595	0
1995	8163	6494	830	30477	13747	37498	8550	6898.	2044
1999	28286	11420.	27597	45526	18107	73558	11921.	8238	13053
Pumped Storage Dispatched Last									
1979	700	384	0.	700	384	0	700.	384	0
1985	1858	1217.	0	2536	1750	1704.	2175	1463	0
1990	2451	1733.	0	3570	2665.	4324.	2975	2165	0
1995	2874	2128	3301	11079	4133	39107	3400	2576	4500.
1999	6565	3048	33584	19644	7986	79729	7085	3582	16415

Table 5-12 (cont'd)

Hydroelectric Pumped Storage Analysis
Peaking Capacity Forecast For - SPP - ERCOT -

Generic Retirement Of Older Units

	Projection II			Median Projection			Dames & Moore Projection		
	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	0	0.	0.	0.	0	0.	0.	0.	0.
1985	0	0.	0.	0.	0.	0.	0.	0.	0.
1990	0.	0.	0.	0.	0	7388.	0.	0.	0
1995	0.	0.	12144	0	0	41613.	0.	0.	5626.
1999	0.	0.	37368.	0.	0.	77460.	0.	0.	22897.
Pumped Storage Dispatched After Oil Steam									
1979	9112	8380.	0.	9112.	8380.	0.	9112.	8380.	0.
1985	12208	11587.	0.	13632.	13052.	0	11993.	11367.	0.
1990	14675	13639.	0.	17671	16722.	0.	13945.	12973.	0.
1995	17843	16771.	374	22721	21893.	15295.	16459	15363.	0.
1999	21283.	20536.	12650.	27714	27232.	44927.	18473.	17577.	1545.
Pumped Storage Dispatched Last									
1979	0.	0.	0	0	0	0.	0.	0.	0
1985	0	0.	0	0.	0.	0.	0.	0.	0.
1990	0	0.	0	0	0	6174.	0.	0.	0.
1995	0.	0.	10888	0	0	39531.	0	0.	3498.
1999	0	0.	35458	0	0.	75237.	0.	0	20583.
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	0.	0	0	0.	0.	0.	0.	0	0
1985	0.	0.	0.	0.	0	0.	0.	0.	0.
1990	0.	0	0	0.	0.	0.	0.	0	0.
1995	0	0	1755	0	0.	21232	0	0.	0
1999	0.	0	14241.	0	0	48733.	0.	0	3005.
Pumped Storage Dispatched After Oil Steam									
1979	9112	8380	0.	9112	8380	0.	9112	8380.	0
1985	9795	9159.	0	11054	10447.	0.	9869.	9235	0
1990	10172	9419	0	12248	11397	0.	10035	9349	0
1995	10306	9419.	0.	13328	12386.	6075	10064	9349	0
1999	10486	9610.	5002	14592	13923	31917	9886.	9349	0
Pumped Storage Dispatched Last									
1979	0	0	0	0	0	0	0	0.	0
1985	0	0	0	0	0	0	0	0	0
1990	0	0	0	0	0	0	0	0	0
1995	0	0	1755	0	0	20119	0	0	0
1999	0	0	13834	0	0	47560	0	0.	2615

Table 5-12 (cont'd)

Hydroelectric Pumped Storage Analysis
Peaking Capacity Forecast For - RMPA - NWPP -

Generic Retirement Of Older Units

	Projection II Peaking Capacity (GWH)	Projection II Peaking Capacity (MW)	Projection II Unsited Base (MW)	Median Projection Peaking Capacity (GWH)	Median Projection Peaking Capacity (MW)	Median Projection Unsited Base (MW)	Dames & Moore Projection Peaking Capacity (GWH)	Dames & Moore Projection Peaking Capacity (MW)	Dames & Moore Projection Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	0	0.	0.	0	0	0.	0.	0.	0.
1985	0	0.	82	0.	0	3218.	0.	0.	0.
1990	0	0.	82	0	0	6955	0.	0	0.
1995	0	0	6673	0	0	17826.	0	0.	597.
1999	0	0	13544	0	0.	29697.	0.	0	4503.
Pumped Storage Dispatched After Oil Steam									
1979	0.	0.	0	0	0.	0.	0.	0.	0.
1985	0.	0.	0.	0.	0.	2875.	0	0.	0
1990	0	0.	0	0.	0	6807.	0.	0	0
1995	0.	0	6655	0	0.	17794.	0.	0	579
1999	0.	0.	13527	0.	0	29665.	0.	0.	4485.
Pumped Storage Dispatched Last									
1979	0	0.	0.	0.	0	0.	0.	0.	0.
1985	0.	0	82	0	0	3218.	0	0.	0.
1990	0	0.	82	0.	0.	6955.	0	0	0.
1995	0	0.	6673	0	0	17821.	0	0.	597.
1999	0.	0.	13544.	0	0	29653	0.	0.	4503.
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	0.	0	0	0	0.	0.	0	0	0.
1985	0.	0.	131.	0	0.	3227	0	0.	0.
1990	0	0.	131.	0.	0.	6900	0	0.	0.
1995	0.	0.	6754	0.	0.	17825.	0	0	737
1999	0.	0	13640.	0	0	29683	0	0	4673.
Pumped Storage Dispatched After Oil Steam									
1979	0.	0	0.	0.	0	0	0.	0	0.
1985	0.	0	0	0	0	2884.	0.	0	0.
1990	0.	0	0	0.	0	6748.	0.	0.	0
1995	0	0	6737	0	0	17792	0.	0	720.
1999	0	0	13622	0.	0.	29651.	0.	0	4656
Pumped Storage Dispatched Last									
1979	0.	0	0	0	0	0.	0	0	0
1985	0	0	131	0	0	3227	0	0	0
1990	0	0.	131	0	0	6891	0	0	0.
1995	0	0	6754	0	0	17825	0	0	737
1999	0	0	13640	0	0	29683	0	0	4673

Table 5-12 (cont'd)

Hydroelectric Pumped Storage Analysis
Peaking Capacity Forecast For - Southern - TVA - VACAR -

Generic Retirement Of Older Units

	Projection II			Median Projection			Dames & Moore Projection		
	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	0.	0	0	0	0.	0	0.	0.	0
1985	1432	1399.	2638	2793	2964.	7069	719	597	2300
1990	3412.	3493.	4571	5165.	5052	17689.	1764	1754	2807
1995	7061	7000.	13067	13708	13048.	37317	2400	2416	4676
1999	13389	13124.	31589	20142	19379	60669.	4548.	4260	5860
Pumped Storage Dispatched After Oil Steam									
1979	2108.	2760	0	2108	2760	0	2108.	2760	0.
1985	5291	5112.	771.	6682.	6591	2892.	4425.	4138	540.
1990	7291	7048.	771	9678.	9234	12974	5367.	5137.	540
1995	10710	10560	9629.	16463.	16251	33879.	6221.	5799.	1968
1999	15616	15682	28550.	22167	21998.	57630.	7762	7337.	3330.
Pumped Storage Dispatched Last									
1979	0.	0	0	0.	0	0.	0.	0.	0.
1985	0	0.	0	108.	111	1929.	0.	0	0.
1990	0.	0.	0.	637.	337.	16432.	0.	0	0
1995	3736	2436	11590	9386	6300	33413	0.	0	2086
1999	15226.	9290.	27343	16026	11142	58513.	0	0	2086.
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	0.	0.	0	0	0	0	0.	0	0
1985	502.	467.	2093	1320.	1142	3329.	118	148.	1894.
1990	797	716	2093	1914.	1814	10225	118	148	1894
1995	922	850	2662	5842.	3259.	27067	118.	148	1894
1999	6249	2243	18665	10449	5880.	46472	118	148.	1894.
Pumped Storage Dispatched After Oil Steam									
1979	2108	2760.	0	2108.	2760.	0.	2108.	2760	0.
1985	3769	3525	656	4922	4639	1097.	3581.	3386	457.
1990	3723.	3616	656	5468	5154	6108.	3334.	3386	457.
1995	3991.	3798	656	9304	6542	23422.	3333.	3386.	457
1999	9440	5252	15714	12851	8459	43434.	3337	3444.	457
Pumped Storage Dispatched Last									
1979	0	0	0	0	0	0.	0	0	0
1985	0	0	0	0	0	0	0	0.	0
1990	0	0	0	0	0	6566	0	0	0
1995	0	0.	0	1628	952	23296	0	0	0
1999	6319	2134.	17028	10883	3523	40748	0	0	0.

Table 5-12 (cont'd)

Hydroelectric Pumped Storage Analysis
Peaking Capacity Forecast For - AZNM - SCNV - NCNV -

Generic Retirement Of Older Units

	Projection II			Median Projection			Dames & Moore Projection		
	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)	Peaking Capacity (GWH)	Peaking Capacity (MW)	Unsited Base (MW)
Base Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	0.	0	8810	0	0.	8810.	0	0	8810.
1985	0	0	14104	0.	0	14104.	0.	0	9737.
1990	0	0.	18757.	0	0	19296.	0.	0.	9737
1995	0	0.	31232	0.	0	35313.	0	0.	13956.
1999	0	0.	46413	193.	126	51364.	0.	0.	20743.
Pumped Storage Dispatched After Oil Steam									
1979	296.	391.	0.	296.	391.	0.	296.	391.	0.
1985	1277	1545.	2594.	1277.	1545	2594.	261.	391.	354.
1990	1562	1709.	9738.	1562.	1709	9739.	287.	391.	1570.
1995	2776.	3026	21362.	3162.	3304.	25414.	356.	441.	5535.
1999	4172	4635.	37102	4885	5185.	41674.	1403.	1427.	14272.
Pumped Storage Dispatched Last									
1979	0.	0	8810	0.	0	8810.	0	0.	8810.
1985	0.	0.	12871.	0.	0.	12871.	0.	0.	9550.
1990	0.	0.	16792.	0	0	16792.	0.	0.	9550.
1995	0.	0.	26321	0.	0.	30052.	0.	0.	10837.
1999	0.	0.	40749	0.	0.	46102.	0.	0.	16426.
Load Management Load Shape									
Pumped Storage Dispatched After Coal Steam									
1979	0.	0	8810	0	0	8810.	0.	0.	8810.
1985	0.	0	11564	0.	0	11564.	0	0	9280.
1990	0	0	14324	0.	0	15123.	0.	0.	9280.
1995	0	0.	24374.	0	0	28465.	0.	0.	9280.
1999	0	0	39696	0.	0	44708.	0.	0	13388
Pumped Storage Dispatched After Oil Steam									
1979	296.	391.	0.	296.	391	0.	296.	391	0
1985	260	391	1583	260	391	1583.	163.	391	306.
1990	445.	391.	6944	445.	391	7306	496.	391.	1072
1995	1647.	440	17407.	1798	539	21415.	1025	391.	2429.
1999	2120.	937	31617.	2366.	1103.	36437	1280	391.	8612.
Pumped Storage Dispatched Last									
1979	0	0.	8810.	0.	0.	8810.	0	0	8810
1985	0.	0	10761	0.	0	10761.	0	0	9280
1990	0	0	13299.	0	0	13299	0	0	9280
1995	0.	0	21700	0	0	25042	0	0	9280
1999	0	0	32473	0	0	37860.	0	0	12359

Table 5-12 (cont'd)

Alternative peaking capacity development was projected and dispatched for the seven composite regions (new peaking was always dispatched after existing pumped storage in the algorithm). The potential for peaking capacity is greater in the median projection of load growth while the Dames & Moore projection produced the lowest peaking capacity. The results were as expected: Higher growth in demand requires increases in capacity development. On examination of the impact of the order of dispatch, the greatest potential for peaking capacity occurs when pumped storage is dispatched after oil steam. When pumped storage is dispatched after coal steam and after all other fuel types, coal is used to drive the peak and oil is then available for peaking capacity. The algorithm uses oil to drive the peak when pumped storage is dispatched after oil steam. This method means oil is now in the base and additional capacity is required to meet the peak; hence, there will be a greater potential for new peaking capacity development.

Pumped storage dispatched after coal steam produced the lowest estimates of potential peaking capacity. The ECAR-MAIN-MARCA region has the greatest potential for peaking capacity development. The Southern-TVA-VACAR and ECAR-MAIN-MARCA regions are the only regions to indicate a potential for peaking capacity development when pumped storage is dispatched after coal steam. The RMPA-NWPP region showed no potential for peaking capacity development under any order of dispatch. All regions are estimated to have a potential for unsited base capacity development, although less than the potential development in the pumped storage capacity development algorithm.

The impact of load management on the need for siting new alternative peaking capacity produces lower estimates than under the base-load shape scenario. Since load management techniques attempt to reduce the peak demand, the need for additional peaking capacity is also reduced. Only the Southern-TVA-VACAR and ECAR-MAIN-MARCA regions show a potential for peaking capacity when pumped storage is dispatched after coal steam. An interesting result from the analysis shows that the potential for unsited base capacity under load management is greater than unsited base capacity, excluding load management in the RMPA-NWPP region. (The RMPA-NWPP region is heavily based with hydro generation, and hydro is used not only for base-load but also to meet peak demand.) A lowering of the load duration curve for the region results in an increase in the need for base-load capacity; this result implies that load management would not be an advantageous pursuit in the RMPA-NWPP region.

Economically, investment in pumped storage should be limited to those regions where the actual total cost of building pumped storage is the lowest expansion alternative. Pumped storage facilities constructed to displace oil in the generating mix implies that oil is priced higher than oil's marginal cost, considering the risk of extracting more oil out of the ground versus the risk of purchasing oil abroad. We believe that load management to share peaks is less expensive than constructing pumped storage in most regions where oil is the displaced generating fuel (these regions include the Northeast and the Pacific Southwest). In the Southeast and ERCOT regions, pumped storage would displace gas instead of oil as the generating fuel.

In summary, the potential for pumped storage development is greatest in the ECAR-MAIN-MARCA and the Southern-TVA-VACAR regions. Estimates vary significantly, depending on the rate of demand growth projected for a particular region, and less significantly with varying retirement and dispatching schedules. As can be seen, the impact of load management has a substantial impact on the projected pumped storage development potential of a region.

5.4 METHODOLOGY

The regional forecasts of the need for pumped storage as developed in the preceding section were computed using a regional "stacking dispatch" production costs model that was specifically written for this application.

In the model, regional electric energy forecasts are equilibrated with the scheduled regional availability of generating capacity. Then, based on the assumption of pumped storage power supply and peaker dispatch order, the additional capacity required to meet energy needs is computed. This may be either pumped storage or alternative (nonstorage) type peaking capacity. The purpose of the calculation is to determine, year by year, the amount required.

5.4.1 Description of Stacking Dispatch

To do this calculations are performed that produce estimates of the additional generation capacity required in each region to meet predicted energy requirements. These additions are in the categories of:

- Base-load generating plants
- Pumped-storage plants or other peak-load generating plants.

The method used is a variation of the stacking dispatch method for determining the energy generated by each plant in a system. In stacking dispatch, illustrated in Figure 5-1, the system loads are rearranged in descending order to form a load duration curve. The generating units are arranged in order of operating cost (Unit 1 being the least expensive), and represented by areas below the load duration curve, in order, with Unit 1 at the bottom. The height of each area is the effective capacity of the unit, and the energy generated by each unit is proportional to the area representing the unit. If the ordinates are loads in megawatts and the abscissae are hours, then the areas give energy in megawatt-hours. Variations on the method are explained below.

The effective capacity referred to above is the product of the rated capacity and the availability of the unit when not in scheduled maintenance. This is equivalent to the product of the rated capacity times (1-forced outage rate). The reserve capacity of the system is the difference between the sum of the rated capacities of the units and the peak load. In our application the peak load equals the sum of the effective capacities so the reserve capacity equals the total expected forced outages. Since actual forced outages will sometimes exceed the

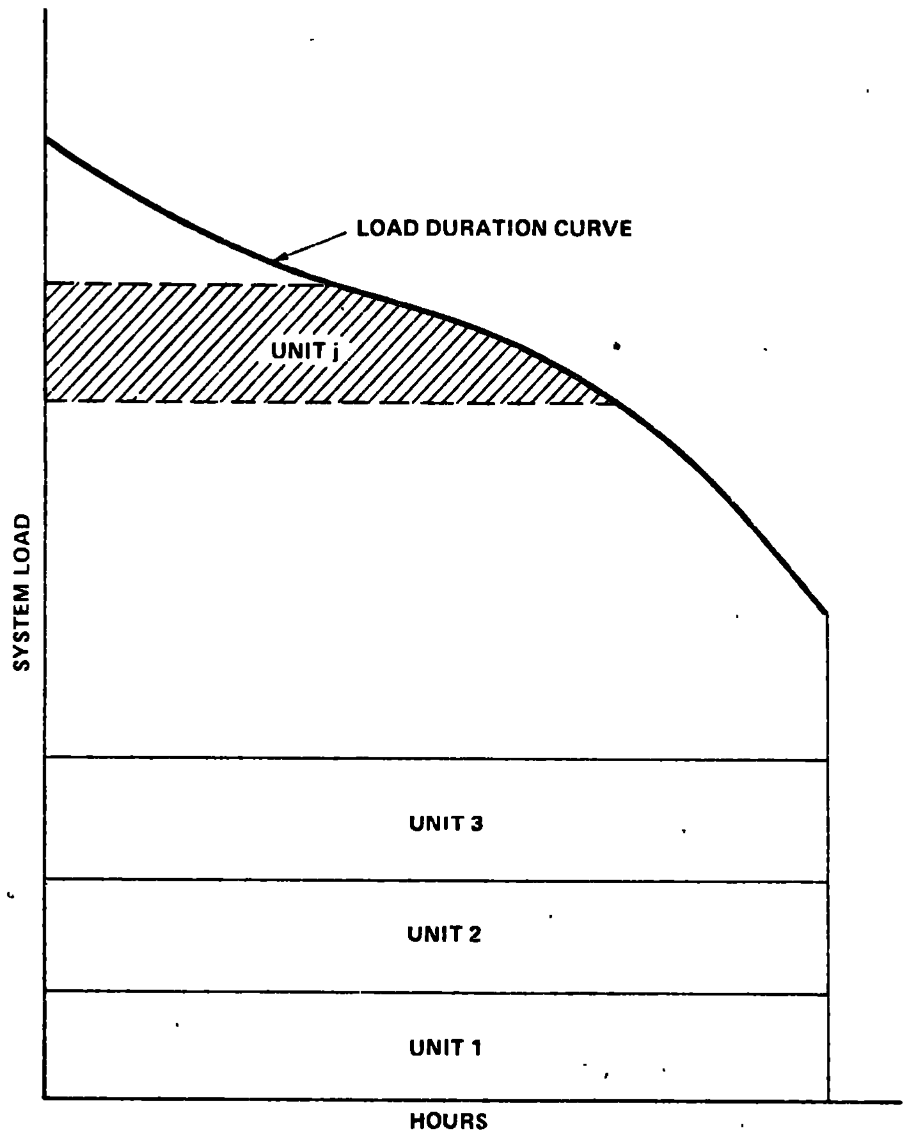


FIGURE 5-1

REPRESENTATION OF UNIT LOADING ORDER AND ENERGY GENERATION REQUIREMENTS IN TERMS OF THE LOAD DURATION CURVE

expected (i.e., average) value, our stacking dispatch model underestimates unserved energy and energy required from peaking units when other units are on forced outage. However, stacking dispatch has been used here, rather than probabilistic dispatch (which treats forced outages more rigorously) for three reasons. First, it is far simpler and more economical in computer time. Second, our objective is to obtain estimates of supportable capacity, and this method will give conservative estimates. Thirdly, our calculations are for Electric Regions containing many generating units (typically 100 or more), and for such large systems the probability of outages exceeding the expected value by a sizeable percentage is quite small. Otherwise stated, stacking dispatch becomes a better representation of the system as a whole as the number of units increases. A detailed description of the model can be found in Appendix C.

5.4.2 Analytical Procedure

The steps in the procedure are as follows:

1) An inventory of existing generating units, planned new units, and planned unit retirements has been made. This includes data on capacities, fuel types, service dates, locations, etc.

2) Three forecasts of electric loads for each region have been obtained, two from previous studies for the Corps of Engineers, and one by Dames & Moore. The corresponding load duration curves are generated from these forecasts.

3) The generating units are grouped into categories according to fuel and operation type. The stacking dispatch is done in terms of these categories rather than by individual generating units; however, there is no change in the principles involved. Certain categories are designated as base-load, intermediate load, and peaking plants; categories are also designated as less or more expensive than pumped storage; and as inexpensive enough to provide power for pumped storage or as too expensive to use. A capacity factor of 20 percent (i.e., operation 20 percent of the time) is assumed as the upper limit for new peakers.

4) The method for calculating additional conventional capacity to be added is to add base capacity until the capacity factor of the highest intermediate plant is 20 percent, and to add peaking capacity to meet any other capacity needed. To illustrate, suppose that with existing

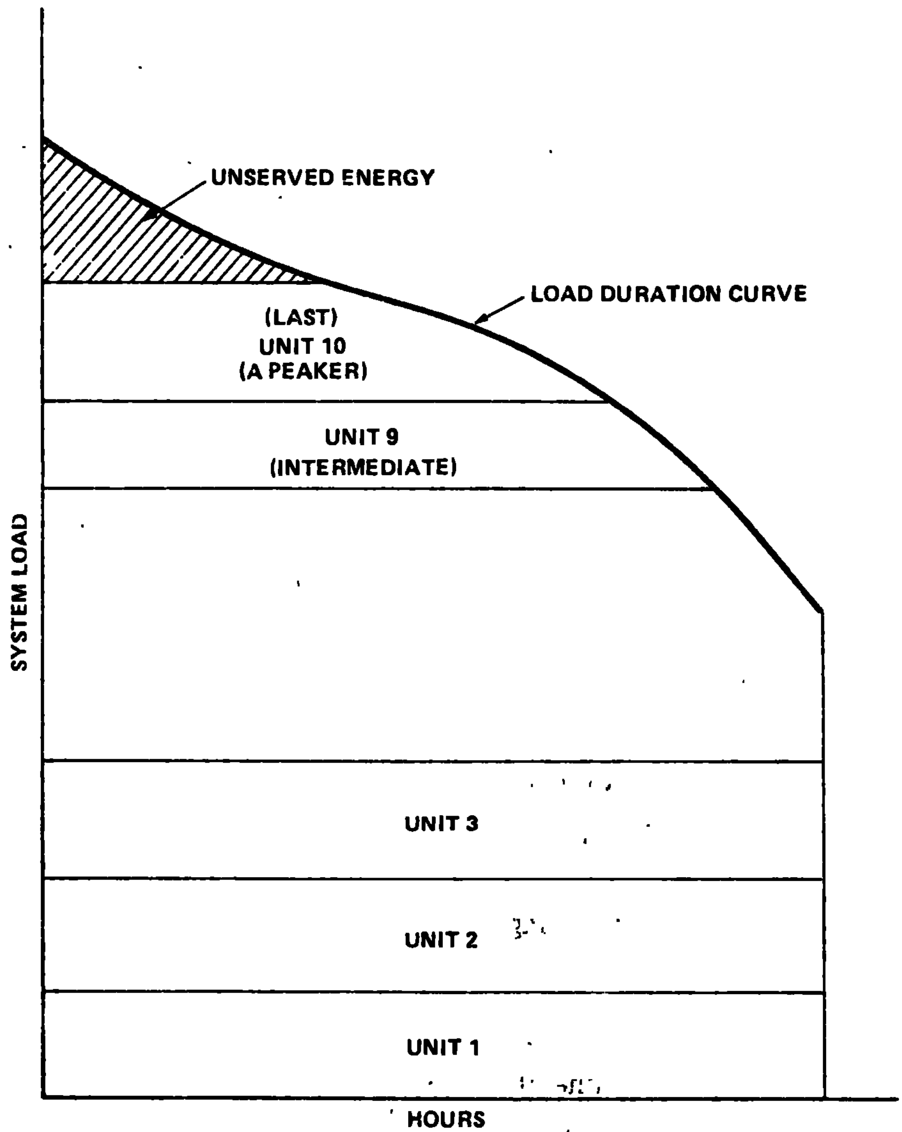


FIGURE 5-2A

REPRESENTATION OF UNIT LOADING ORDER AND ENERGY GENERATION REQUIREMENTS BEFORE CAPACITY ADDITIONS

capacity and load growth the dispatch diagram was as in Figure 5-2A. Additional capacity is added as shown in Figure 5-2B--the new (unsited) base capacity is assumed to be the most economical plant and is added at the bottom. Its capacity is chosen to move the top of Unit 9 (the last intermediate plant) up to a 20-percent capacity factor. Additional peaking capacity is added above Unit 9, and below Unit 10 that is sufficient to move the top of Unit 10 to the peak of the load duration curve.

5) The method for determining additional pumped storage to be added is somewhat similar. In this case both unsited base capacity and additional pumped storage capacity have to be added. These additions will replace all peakers more expensive to run than pumped storage and will effectively retire them. The two conditions to be met are:

- Total effective capacity must equal peak load
- The energy available for economical pumping must equal the energy generated by the pumped storage plus its pumping and generating losses.

Expressing these relations mathematically gives equations from which the pumped storage capacity can be calculated. The resulting dispatch diagram is Figure 5-2C, in which the hatched area (upper right) is the additional load due to pumping and in which it is assumed that Unit 9 is less expensive to operate than pumped storage, but not economical enough to furnish pumping energy when the round trip efficiency (about 72 percent) is considered. The generating capacity is here assumed to be equal to the pumping capacity.

6) Calculations implementing the procedures of (4) and (5) above are performed for summer and winter of each year for each electricity region to determine the amounts of base and peak or pumped storage needed over and above planned expansion.

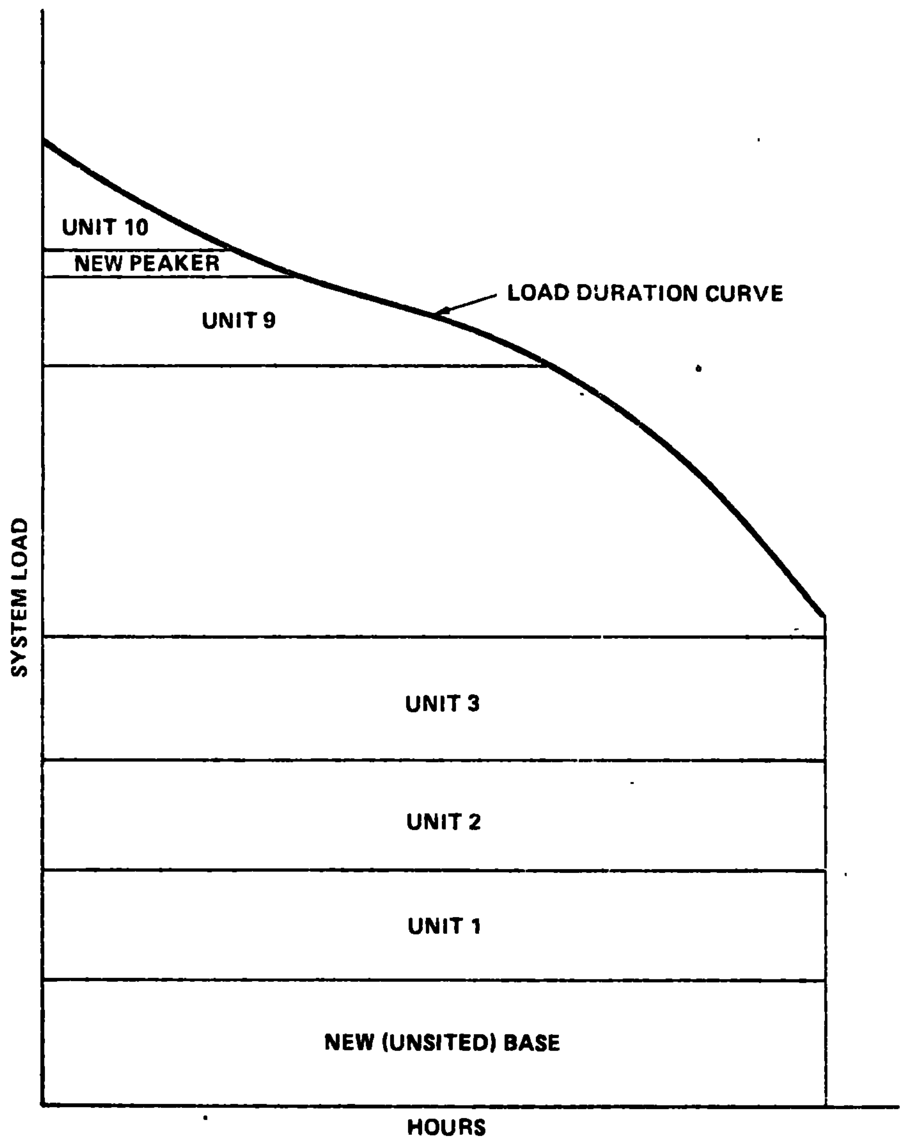


FIGURE 5-2B

REPRESENTATION OF UNIT LOADING ORDER AND ENERGY GENERATION REQUIREMENTS AFTER CAPACITY ADDITIONS

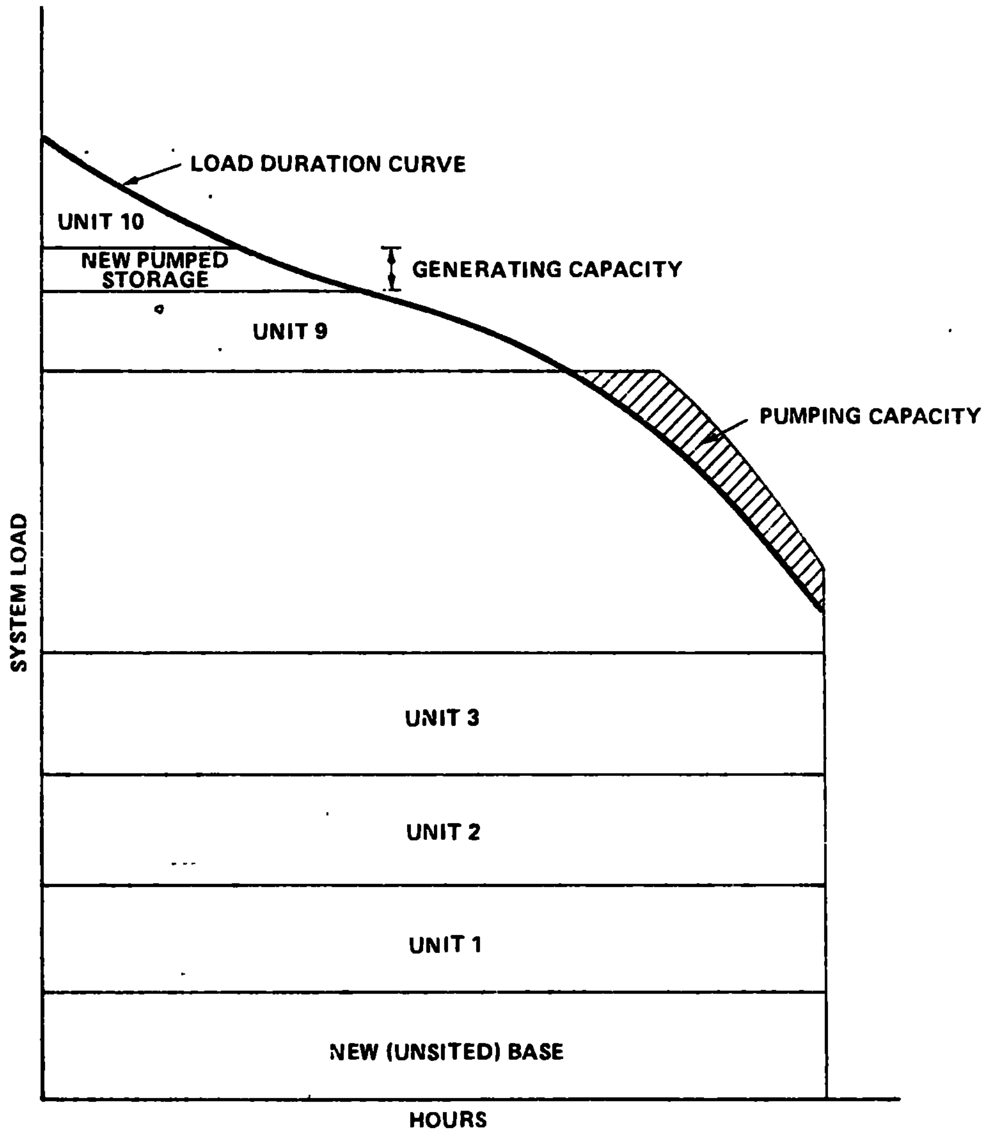


FIGURE 5-2C

REPRESENTATION OF UNIT LOADING ORDER AND ENERGY GENERATION REQUIREMENTS AFTER ADDING BASE AND PUMPED STORAGE

5.5 FINANCIAL AND CONSUMER COST IMPACTS

5.5.1 Causes and Impacts

The purpose of this analysis is to quantify reasons why, in the current economic climate, the new construction of generating equipment (including pumped storage) is proceeding at such a slow pace. From all evidence, the principal difficulty seems to be project financing. This is because, at present, investor owned utility companies are paying record interest on their new debt and because their stocks are selling (in general) below book value. Under these circumstances, utilities are driven to discourage expenditures. Their hope is to defer construction until financing is easier. Their objective is control of their long-run cost structure, even though construction of new coal-fired, nuclear base-load, or pumped storage facilities would result in long-term savings of both money and oil. Specifically there are two reasons to postpone as much construction as possible. First is the increase in the cost of the plant due to the current, unusually high interest rates on money borrowed for construction. This raises costs over the long run. The second is the increase in the cost of electricity produced by the system because construction is being concurrently pursued with operations. This causes both short- and long-run problems, which will be illustrated in this analysis.

In the case of a new, just begun construction project, if these costs are passed along to customers as the costs of construction work in progress (CWIP) and figured into the rate base prior to plant startup, then electric rates will increase over the short run and the public is sure to complain. If the costs are carried by the owners, many companies, because of their current weak financial position will operate below a minimum acceptable return on investment. Under these conditions investors are unlikely to subscribe to any of their new debt or additional stock issues, and the company will eventually find it extremely difficult to raise capital.

5.5.2 New Coal Construction vs. Utilization of Existing Oil Capacity for Pumped Storage Energy Supply

5.5.2.1 Cost Comparison

To illustrate these effects, consider the case of the Hypothetical Electric Power Company. (For the purposes of these calculations no inflation has been assumed; thus the following analysis will understate the adverse impacts of new construction.) The company that is typical of generating companies in the Northeast has the following generation mix and physical plant costs:

MW	Type	Original Costs (mega$)
500	Hydro	100
1,000	Nuclear	830
1,800	Oil	720
	Transmission, distribution, etc.	550
		2,200

As is typical of the industry, the equipment for this generating system was purchased some time ago. The current capital carrying charges are 6 percent a year, or 132 mega$/year, far less than the amount of their replacement carrying charges.

For the purpose of this analysis, let us assume that the Hypothetical Power Company is now purchasing oil at $40 a barrel, equivalent to $68/MWh. Were it operating a coal plant, it could purchase coal at $50 a ton; this is equivalent to $21/MWh. The company is now generating 17,000 GWh a year, an average load of 1,941 MW, and thus has a sizeable reserve capacity in oil-burning units. We shall assume that hydro runs at a 40-percent capacity factor, and that nuclear plants have operating costs of $10/MWh and a capacity factor of 70 percent. We shall assume also that the maintenance costs on existing plants are $30 million a year; all other operating costs net out to $150 million a year and increase $10 x 10^6/year; and the company has been making net earnings of 7 percent on investment, or 154 mega$/year. As noted, we shall assume no inflation (alternatively, we could be saying that cost changes are superimposed on the general inflation). The load is assumed to grow at a 3-percent annual growth rate, or at 500 GWh per year.

To accommodate this growth, we will consider two possibilities: (1) construction of a 1,000-MW, coal-fired plant costing $1,600/kw during a 7-year period; and (2) meeting increased demand during the next decade solely by the utilization of existing, unused oil-fired generating capacity. As must be patently obvious, the economic advantage of (1) over the long term is overwhelming (if it can be financed). The thrust of the following analysis lies in the short-term cost to the consumer since it is this cost that receives the most scrutiny from the various state public utility commissions. For the construction we assume expenditures in years 1-7 of $100, $200, $300, $400, $300, $200, and $100 million, respectively, and we assume an annual carrying charge of 12 percent.

The generation cost can be computed as follows:

Hydro	10^{-6} x \$0 x .4 x 8,760 x 500	= 3.066 x 0 =	0
Nuclear	10^{-6} x \$10 x .7 x 8,760 x 1,000	= 6.132 x 10 =	61.320
Oil	(49.47 percent capacity factor)	7.802 x 68 =	530.536
			591.856
		Carrying	132.
		Maintenance	30.
		Operating	150.
			903.856

Additional cost of 1,000 GWh from oil is \$68 x 10^6.

Savings for 6,132 GWh from coal is 6.132 (68-21) x 10^6 = 288.2 x 10^6\$.

Results for the two alternatives over 10 years are given in Table 5-13.

A look at these figures leads to the following conclusions:

(1) The cost to consumers for electricity rises at about 2 percent (in a no-inflation case), because all the growth in the system is taken by electricity and no new coal capacity is added.

(2) Alternatively, until the construction work is completed, if the cost of building the coal plant is passed on to the customers as CWIP in the rate base (which is the way that provides for the minimum financial pressure on the utility), the cost of electricity will rise about 4 percent a year above inflation. When the coal plant is placed in service, the cost of electricity will fall sharply, back to the point at which the price rises started, then resume its rise as oil is again burned to meet growth (as in (1) above).

(3) If the cost of building the coal plant is not in the rate base, and rate increases merely balance increased fuel costs, then during the last 3 years of construction the carrying charge on CWIP will reduce net earnings to zero, or below. If, on the other hand, interest charges (and therefore carrying charges) were more nearly at their historical values, and if rates were such that the company could operate at its authorized rate of return, then the company could afford to finance the coal plant and will prosper, the customers would save money in the long run, and the use of imported oil would be reduced.

TABLE 5-13

Comparative Costs of Existing Oil or New Coal Base Generation

Year	GWH 10^3 x	Add Coal Carrying 10^6\$	Cost of Sales			
			Oil, 10^6\$	Oil\$/MWH	Coal, 10^6\$	Coal\$/MWH
1	17	12	904	53.18	916	53.88
2	17.5	36	943	53.89	979	55.94
3	18	72	982	54.56	1,054	58.56
4	18.5	120	1,021	55.19	1,141	61.68
5	19	156	1,060	55.79	1,216	64.00
6	19.5	180	1,099	56.36	1,279	65.59
7	20.	192	1,138	56.90	1,330	66.50
8	20.5	192	1,177	57.41	1,081	52.73
9	21	192	1,216	57.90	1,120	53.33
10	21.5	192	1,255	58.37	1,159	53.91

5.5.2.2 Minimum Revenue Requirements (MRR)

For another point of view on the factors affecting the implementation of pumped storage, we have considered a region using large amounts of oil to generate electricity (e.g., New England, Florida) and having ample reserve capacity. We have calculated the MRR for two scenarios. The first consists of operating existing oil-burning plants using oil costing $40/barrel. The price of oil was assumed to escalate at 1 percent above general inflation. The second consists of constructing a new coal plant with supplemental pumped storage; it would burn coal costing $50/ton and the capital cost would be $1,500/kw. Both the oil and coal plants were assumed to have a capacity of 1,000 MW and 70-percent capacity factors. We assumed inflation of 10 percent in the first year, falling linearly to 0 percent in the tenth year; debt interest at 12 percent per year; and return on equity of 10 percent per year in the first year, falling linearly to 5 percent per year in the tenth year. A plant life of 35 years with Iowa Curve dispersion type R1 was assumed. The results of these calculations are shown in Tables 5-14 and 5-15, which present, respectively, the levelized lifetime revenue requirements and the annual minimum revenue requirements for the two scenarios.

5.5.2.3 Conclusions

These results show the overwhelming long-run superiority of using coal supplemented by pumped storage rather than using oil. If the price of oil did not escalate at all, the MRR for oil would be $531 million/year, as shown in the first line of Table 5-15, and this would exceed any MRR for the coal scenario (the last column of the same table). Thus, it is clearly economical to replace oil by coal if financing to build the latter can be arranged.

5.5.3 Pumped Storage in an Existing System with Excess Coal Base Generating Capacity

5.5.3.1 Cost Comparisons

Now consider a utility with a large amount of existing coal-burning generating capacity that has adequate peaking capacity, a common situation in the Midwest. As the system load increases, the utility must add peaking capacity, either pumped storage, combustion turbine, or some other. Let us compare two scenarios: (1) the addition of 500 MW of pumped storage having 70 percent efficiency, a 15-percent capacity factor, and costing $300/kw; and (2) the addition

TABLE 5-14

Summary of Lifetime Revenue Requirements (Levelized)
(millions of dollars per year)

	Oil Only	Coal + P.S.
Return on net investment	0	114
Economic depreciation	0	43
Income tax	0	15
Fuel, operation, maintenance	890	310
	890	481

TABLE 5-15

Annual Minimum Revenue Requirements
(millions of dollars)

Year	Oil Only	Coal + P.S.
1	531	386
2	580	448
5	710	460
15	864	429
25	955	399
35	1,054	366

of 500 MW of combined-cycle capacity costing \$200/kw, having a heat rate of 9,000 BTU/kWh and a 15-percent capacity factor. Suppose the system consists of:

MW	Type	Original cost (10^6\$)
3,800	Coal	1,000
300	Peakers (old)	30
	Transmission and distribution	270
		1,300

The existing plant was purchased some time ago and the carrying charges are 6 percent/year or \$78 x 10^6/year. Again we assume the company is now generating 17,000 GWh a year, increasing by 500 GWh a year. For the pumped storage construction we assume expenditures in years 1-7 of \$10, \$20, \$30, \$30, \$30, \$20, and \$10 million, respectively, and an annual carrying charge of 12 percent. The combined-cycle plant construction is assumed to take a year and will come on-line at the same time as the pumped storage plant.

The calculated generating cost for the first year is:

Peakers	300 x .15 x 8,760 x 61.72 =	24.33 x 10^6
Coal	(17,000 - 394) x 1,000 x 22.80 =	378.62
	Carrying	78.
	Operation and maintenance	180.
		660.95

This rises by 500 x 100 x 22.8 = \$11.4 x 10^6/year for fuel and \$5 x 10^6/year for operation and maintenance until a new peaker comes on line. At this time the load on coal is 20,500 - 394 = 20,106 GWh, representing a capacity factor of 60.4 percent.

In this case the plant added to the system, whether pumped storage or combined cycle, is relatively inexpensive, so the carrying charges are not great. Although the cost of carrying the construction of the pumped storage increases the cost of generating electricity by as much as \$0.76/MWh, this is a relatively small percentage increase. Again, in the long term the pumped storage will pay for itself, provided coal remains less expensive than oil, as we have assumed.

The comparative costs for meeting new requirements by adding pumped storage capacity and by adding new combined cycle peaking capacity are shown in Table 5-16.

5.5.3.2 Minimum Revenue Requirements (MRR)

Using the same assumptions on falling inflation and fuel prices as in Section 5.5.2, we have calculated the revenue requirements for: (a) 500 MW added pumped storage using existing coal plants, and (b) 500 MW additional combined-cycle peaking plants. The assumptions regarding inflation were similar to those used before. The results are given in Tables 5-17 and 5-18, which show, respectively, the levelized lifetime requirements and the annual minimum revenue requirements for the two scenarios.

5.5.3.3 Conclusions

These results show the expected, overwhelming long-run superiority of using coal supplemented by pumped storage rather than using oil in a combined-cycle plant. If the price of oil did not escalate at all, the MRR for oil would be $52 million/year as shown in the first line of Table 5-18, and this would exceed any MRR for the coal scenario (in the first column of the same table). Thus it is clearly more economical to provide peaking energy by the use of pumped storage rather than by adding oil-burning, combined-cycle plants, if financing and authorization (permits, licenses, approvals, etc.) of the pumped storage facility can be arranged.

TABLE 5-16

Comparative Costs of Adding Pumped Storage or Combined Cycle

Year	GWH x 10^3	Pumped Storage Carrying	Operation and Maintenance Coal	Coal for Pumped Storage	Combined Cycle Fuel	Combined Cycle Carrying	Pumped Storage $	Pumped Storage $/MWH	Combined Cycle $	Combined Cycle $/MWH
1	17.	1.2	661.0				666.2	38.95	661.0	38.88
2	17.5	3.6	677.4				681.0	38.91	677.4	38.71
3	18.	7.2	693.8				701.0	38.94	693.8	38.54
4	18.5	10.8	710.2				721.0	38.97	718.2	38.39
5	19.	14.4	726.6				741.0	39.00	726.6	38.24
6	19.5	16.8	743.0				759.8	38.96	743.0	38.10
7	20.	18.0	759.4			12.	777.4	38.87	771.4	38.57
8	20.5	18.0	764.4	20.8	40.5	12.	803.2	39.18	821.9	39.85
9	21.	18.0	769.4	20.8	40.5	12.	808.2	38.49	821.9	39.14
10	21.5	18.0	774.4	20.8	40.5	12.	813.2	37.82	826.9	38.46

TABLE 5-17

Summary of Lifetime Revenue Requirements (Levelized)
(millions of dollars per year)

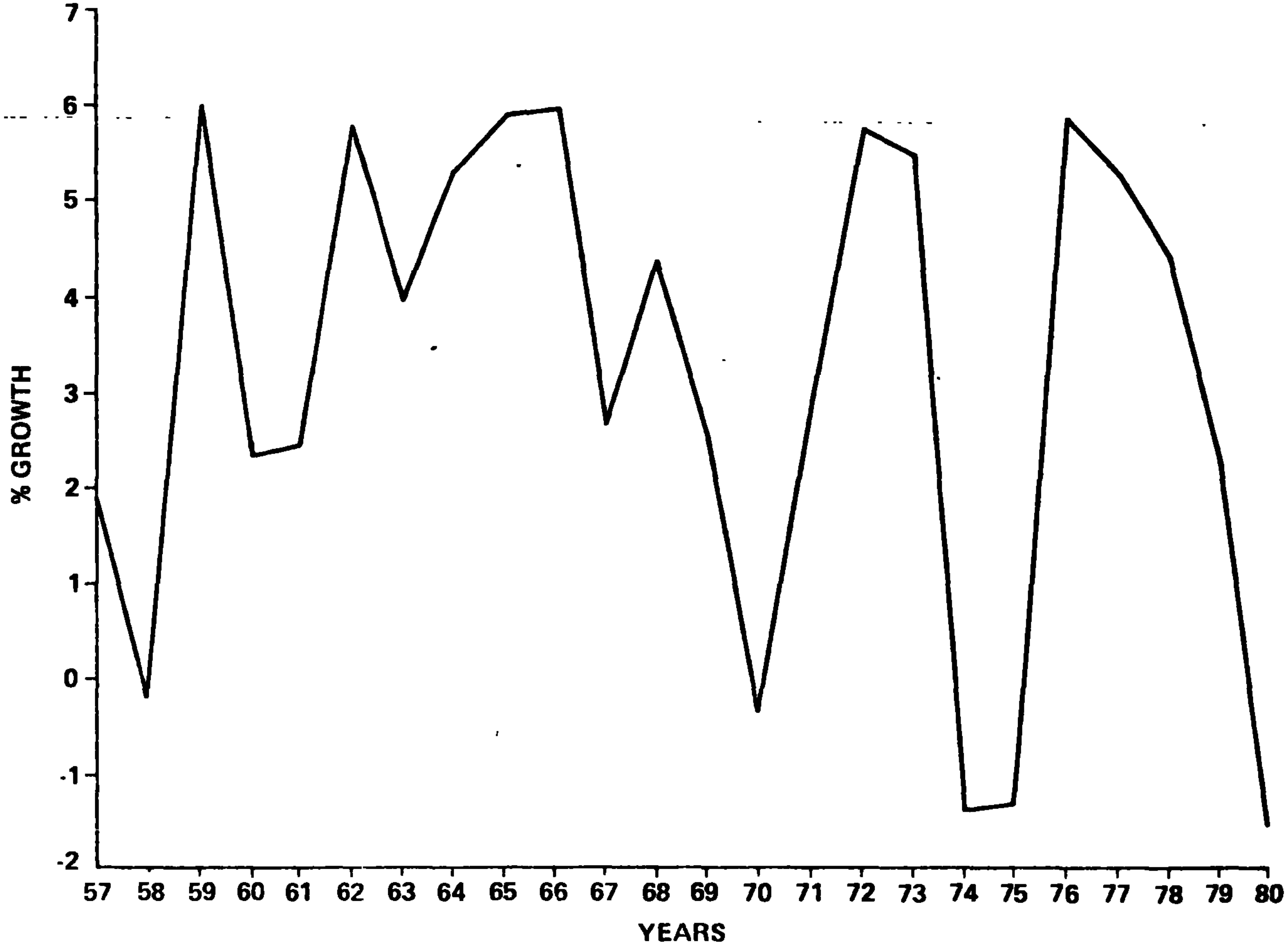
	Pumped Storage	Combined Cycle
Return on net investment	11	8
Economic depreciation	4	3
Income tax	1	1
Fuel, operation, maintenance	32	61
	48	73

TABLE 5-18

Annual Minimum Revenue Requirements
(millions of dollars)

Year	Pumped Storage	Combined Cycle
1	39	52
2	46	59
5	47	66
15	44	67
25	40	65
35	37	63

EXHIBITS



GROSS NATIONAL PRODUCT
ANNUAL GROWTH RATES

EXHIBIT 1

DAMES & MOORE

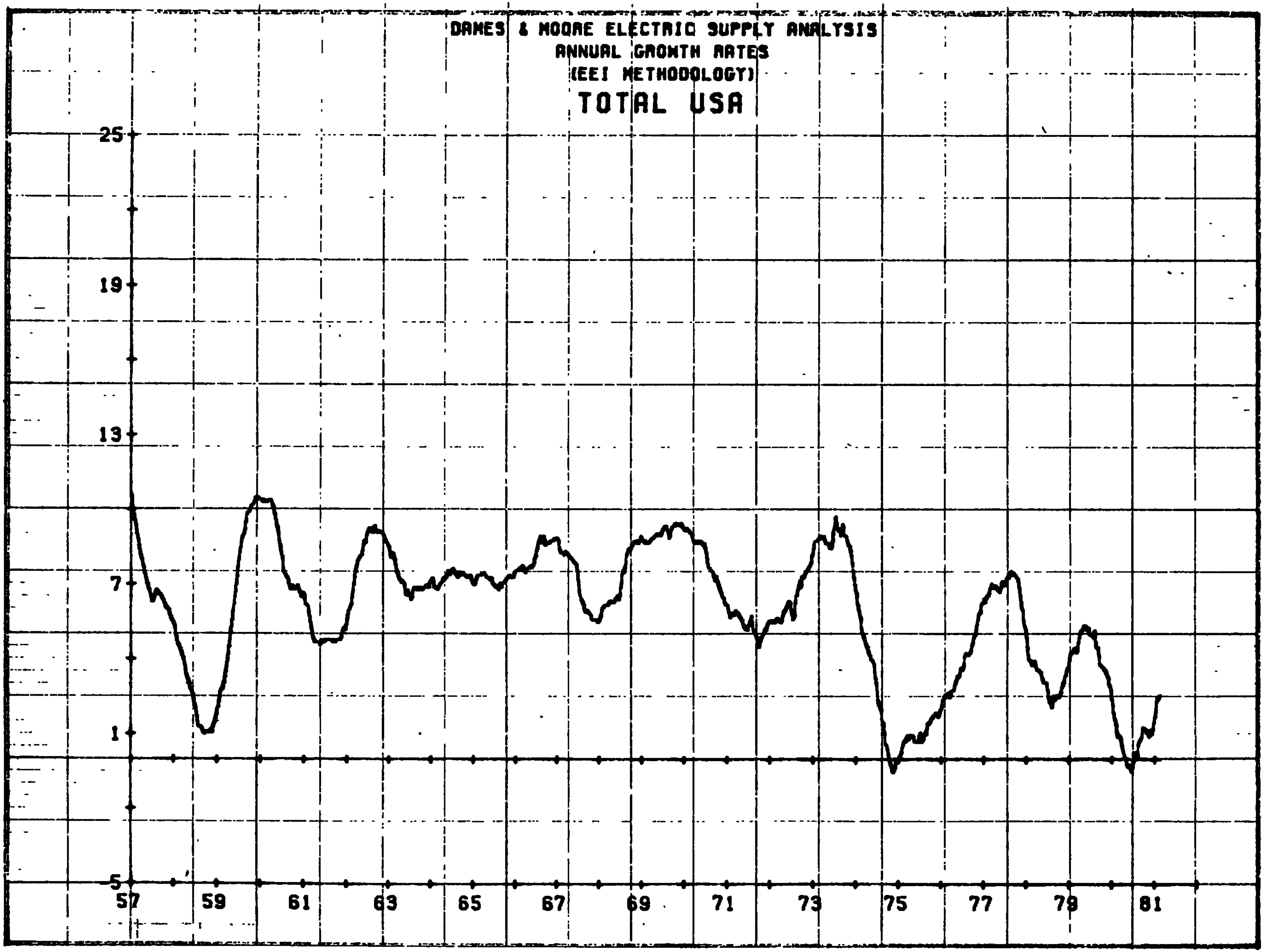

DAMES & MOORE ELECTRIC SUPPLY ANALYSIS
ANNUAL GROWTH RATES
(EEI METHODOLOGY)
TOTAL USA
25
19
13
7
1
-5
57
59
61
63
65
67
69
71
73
75
77
79
81

EXHIBIT 2

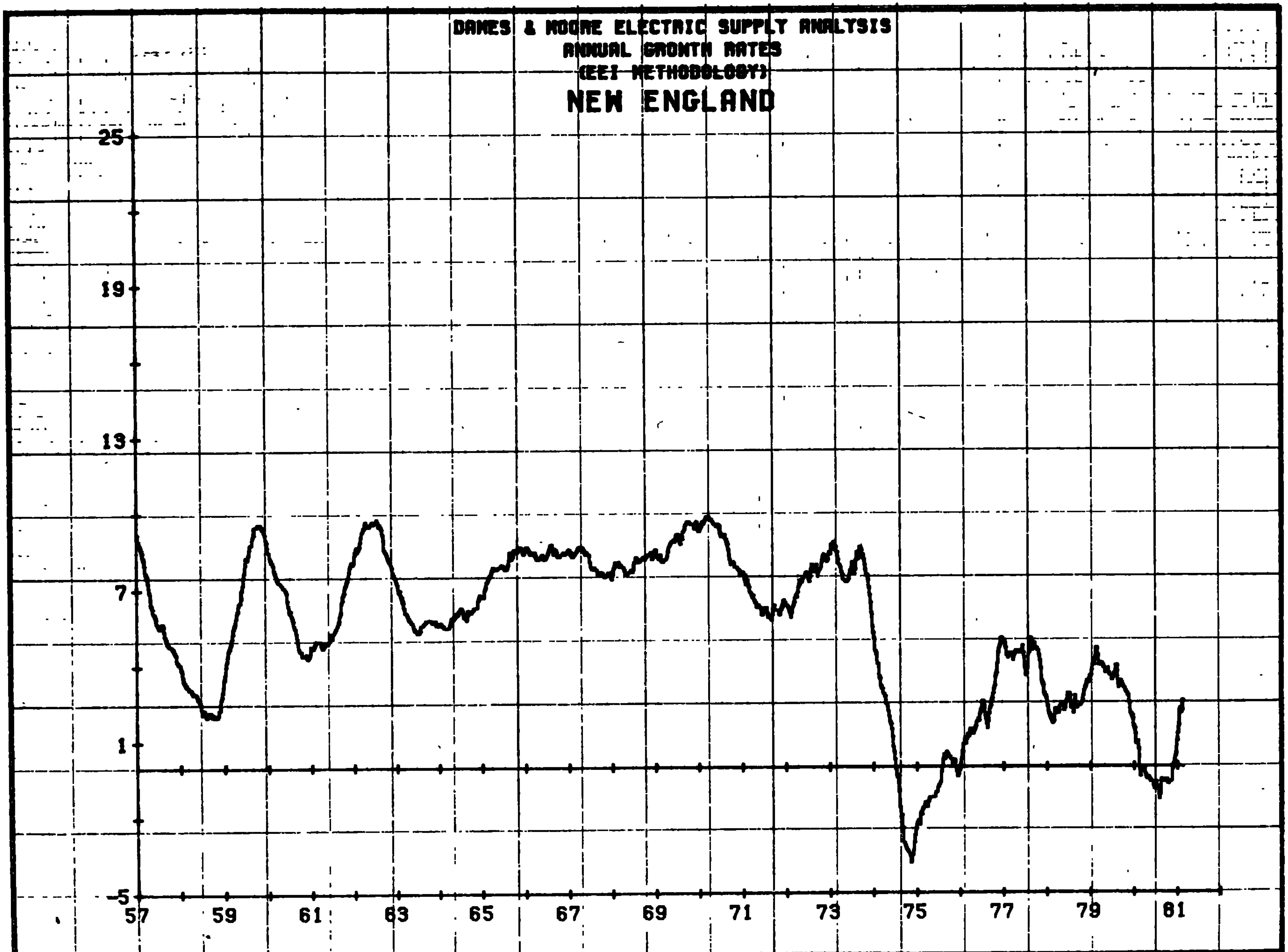


EXHIBIT 3

5-81

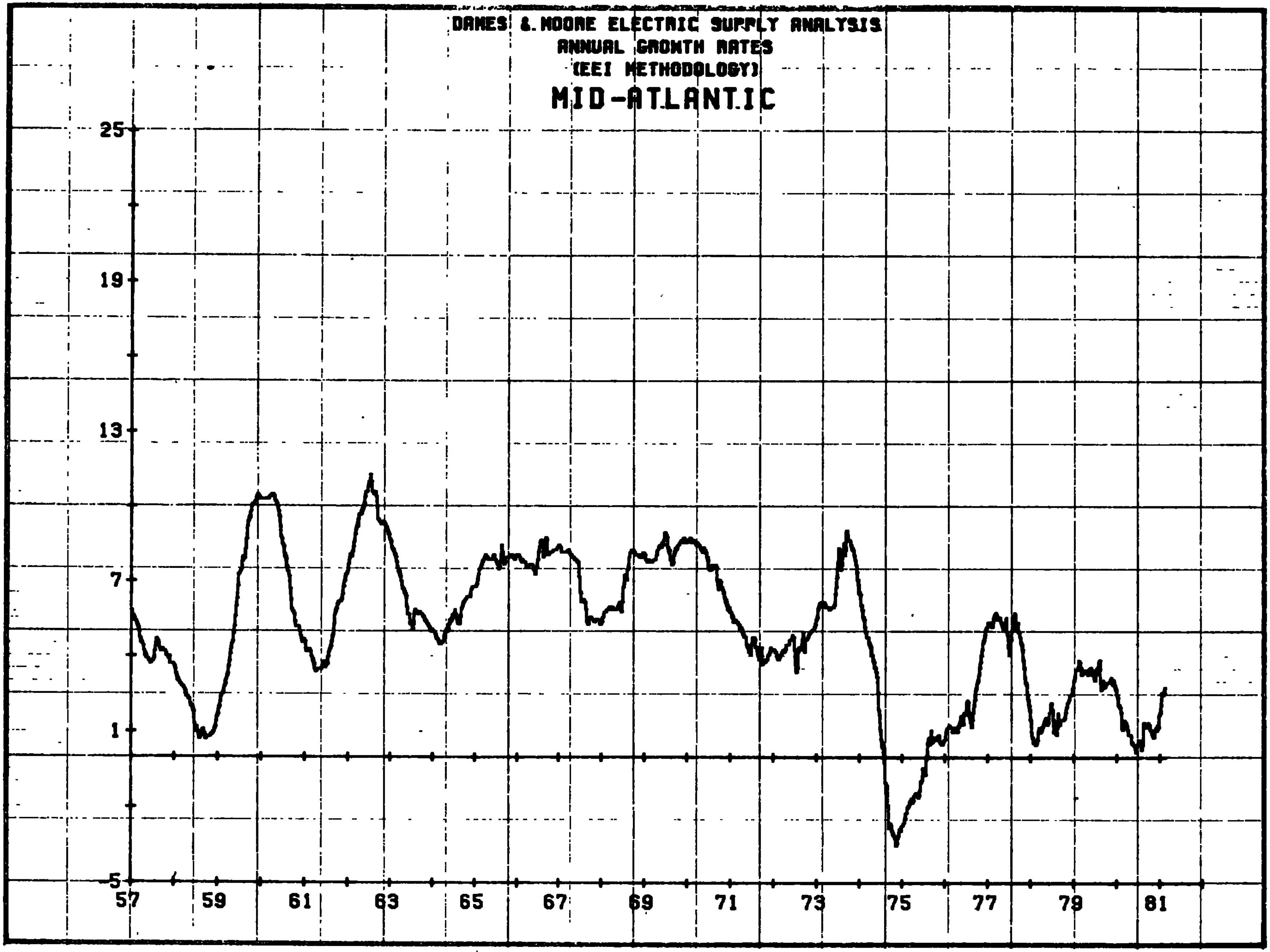
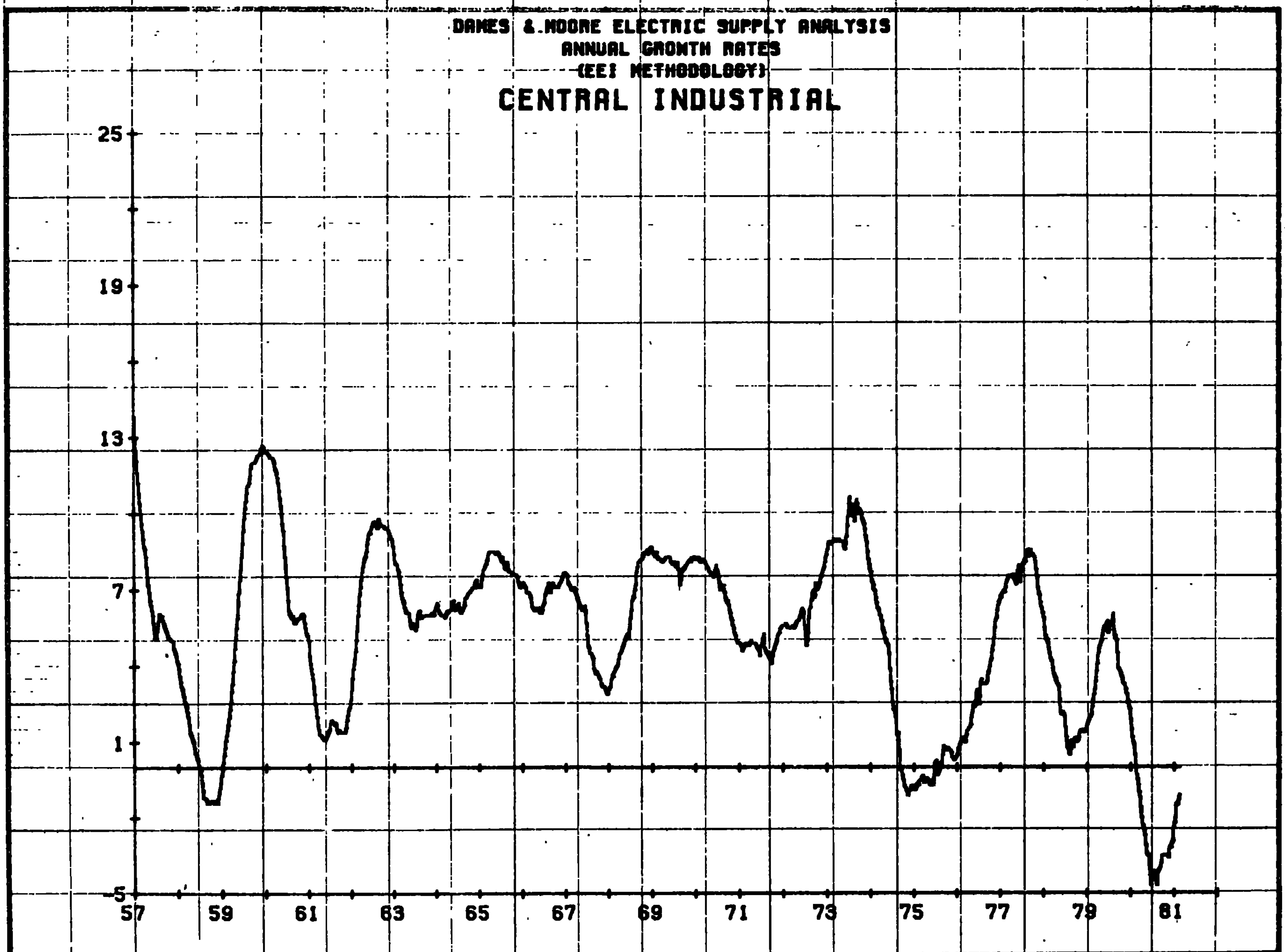

DAMES & MOORE ELECTRIC SUPPLY ANALYSIS
ANNUAL GROWTH RATES
(EEI METHODOLOGY)
MID-ATLANTIC
25
19
13
7
1
-5
57
59
61
63
65
67
69
71
73
75
77
79
81

EXHIBIT 4



5-83

EXHIBIT 5

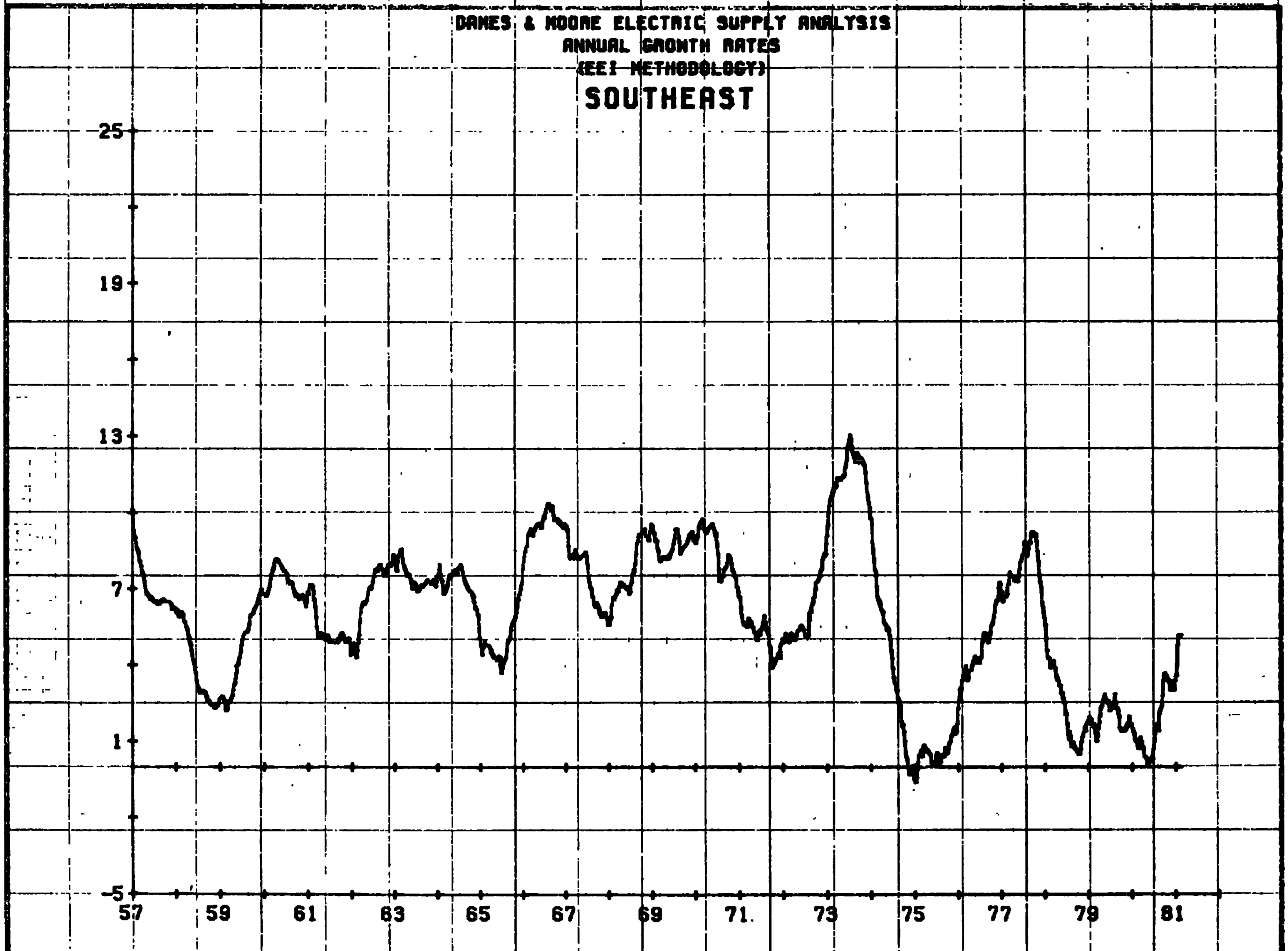

DAMES & MOORE ELECTRIC SUPPLY ANALYSIS
ANNUAL GROWTH RATES
(EEI METHODOLOGY)
SOUTHEAST
25
19
13
7
1
-5
57
59
61
63
65
67
69
71
73
75
77
79
81

EXHIBIT 6

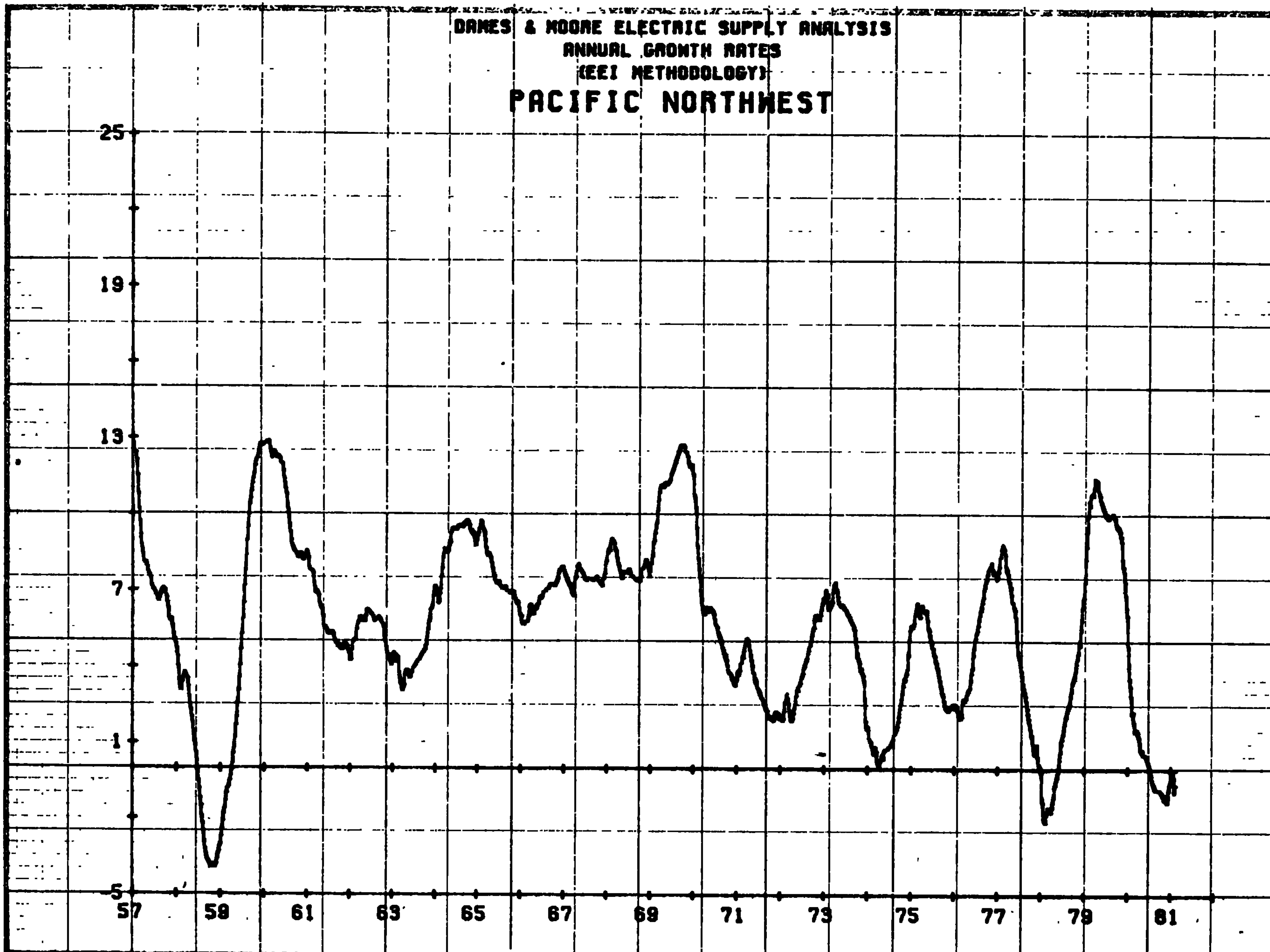
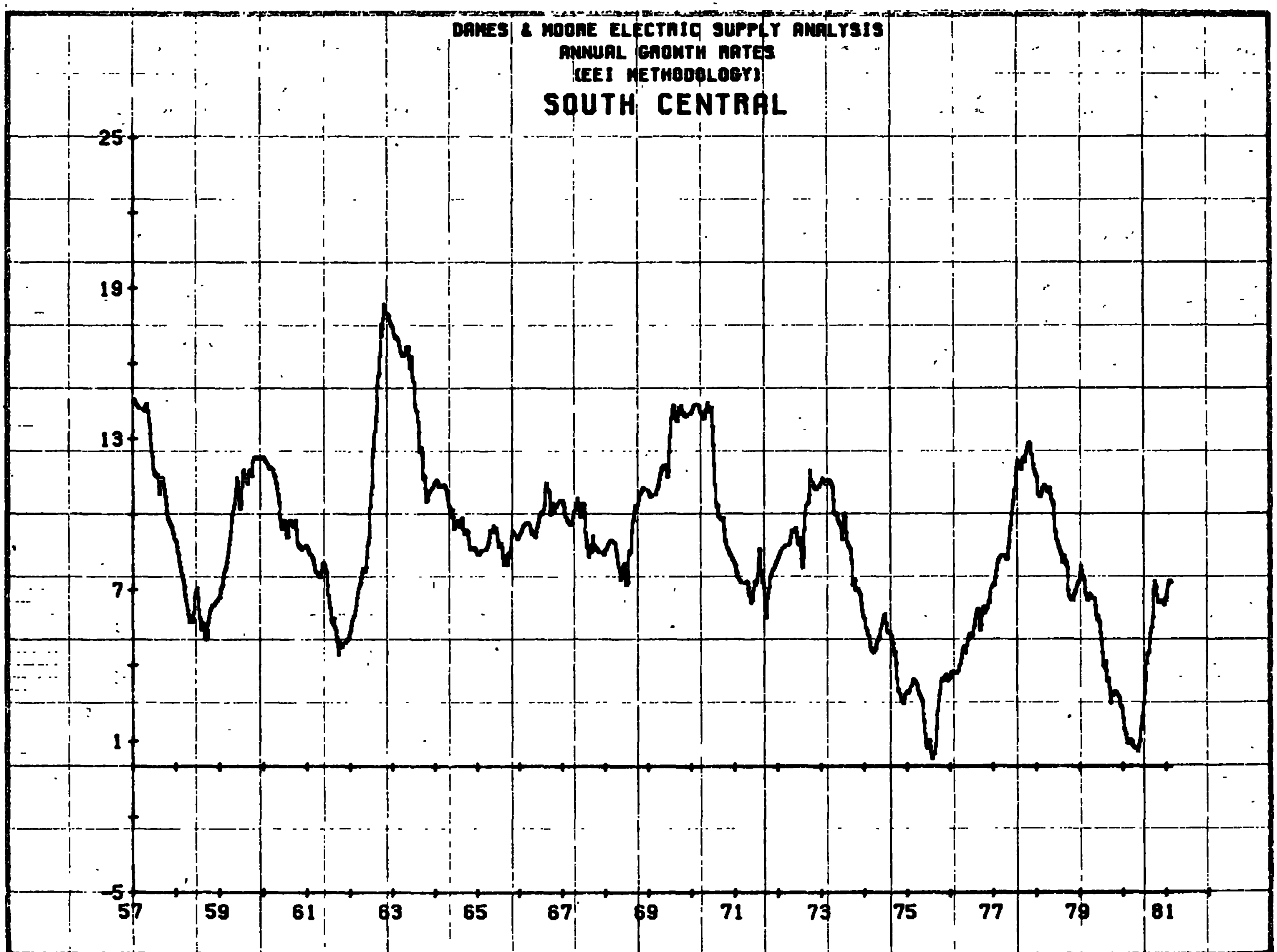

DAMES & MOORE ELECTRIC SUPPLY ANALYSIS
ANNUAL GROWTH RATES
(EEI METHODOLOGY)
PACIFIC NORTHWEST
25
19
13
7
1
-5
57
59
61
63
65
67
69
71
73
75
77
79
81

EXHIBIT 7

EXHIBIT 8

5-86



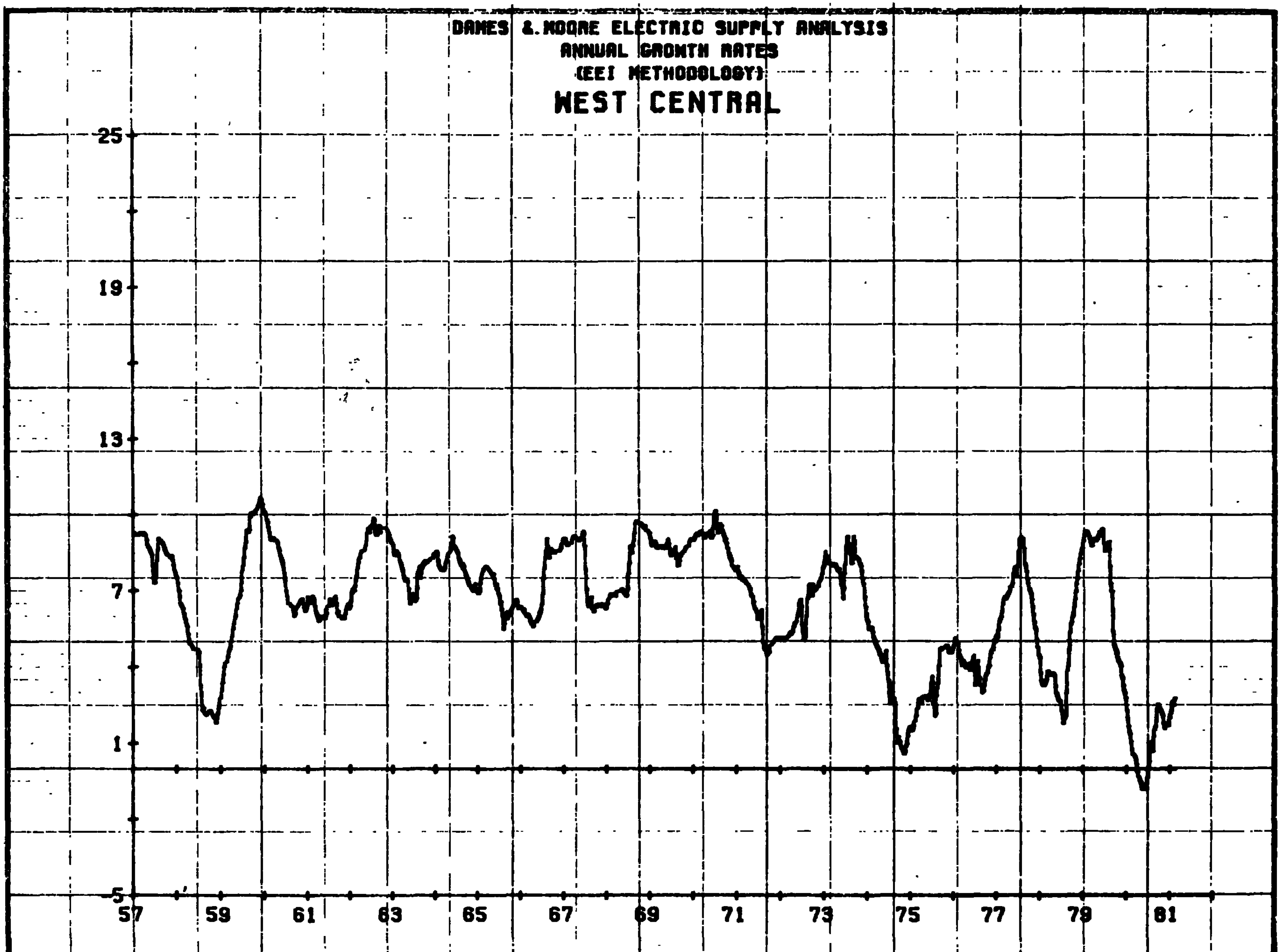
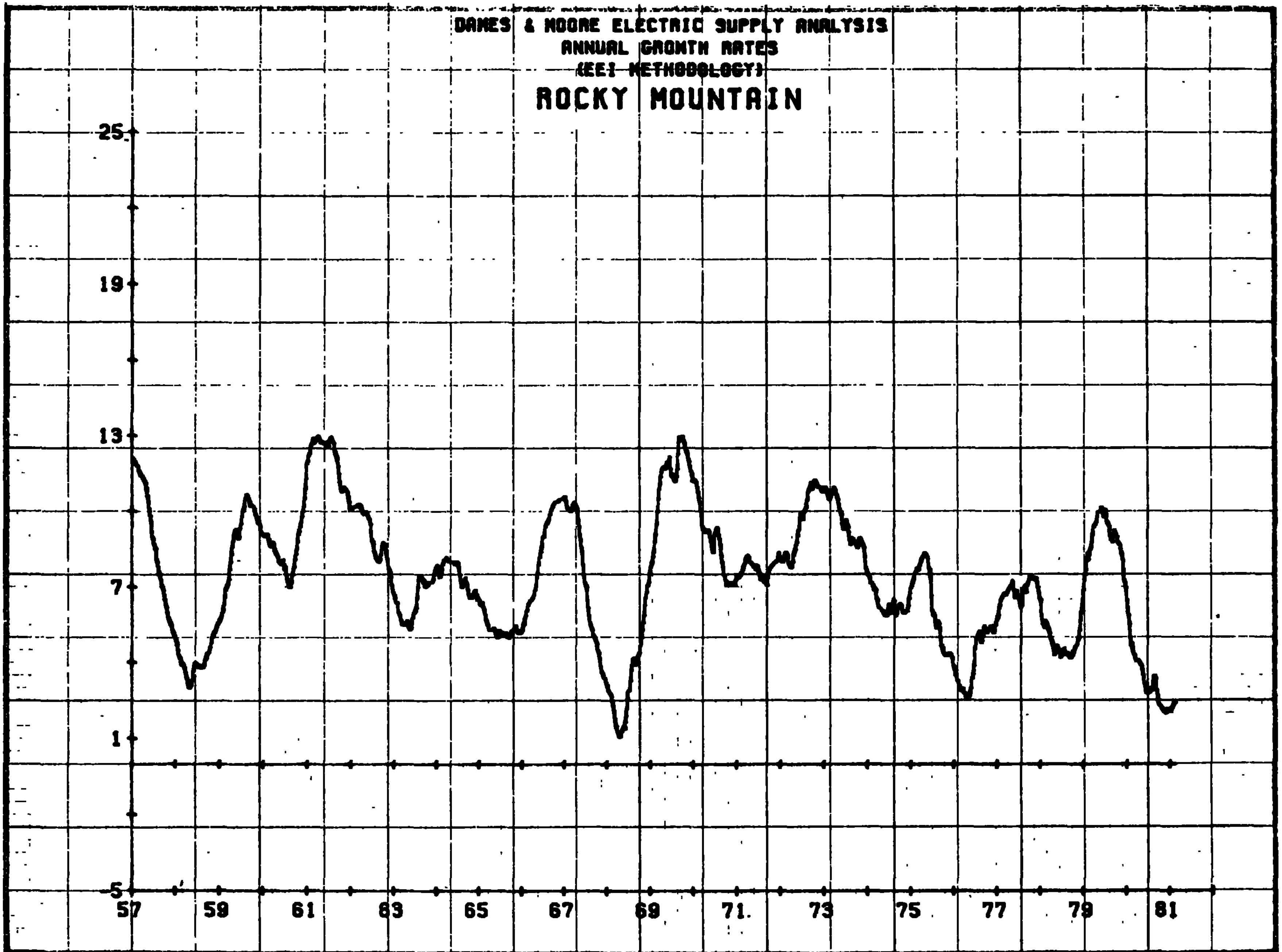

DAMES & MOORE ELECTRIC SUPPLY ANALYSIS
ANNUAL GROWTH RATES
(EEI METHODOLOGY)
WEST CENTRAL
25
19
13
7
1
-5
57
59
61
63
65
67
69
71
73
75
77
79
81

EXHIBIT 9



5-88

EXHIBIT 10

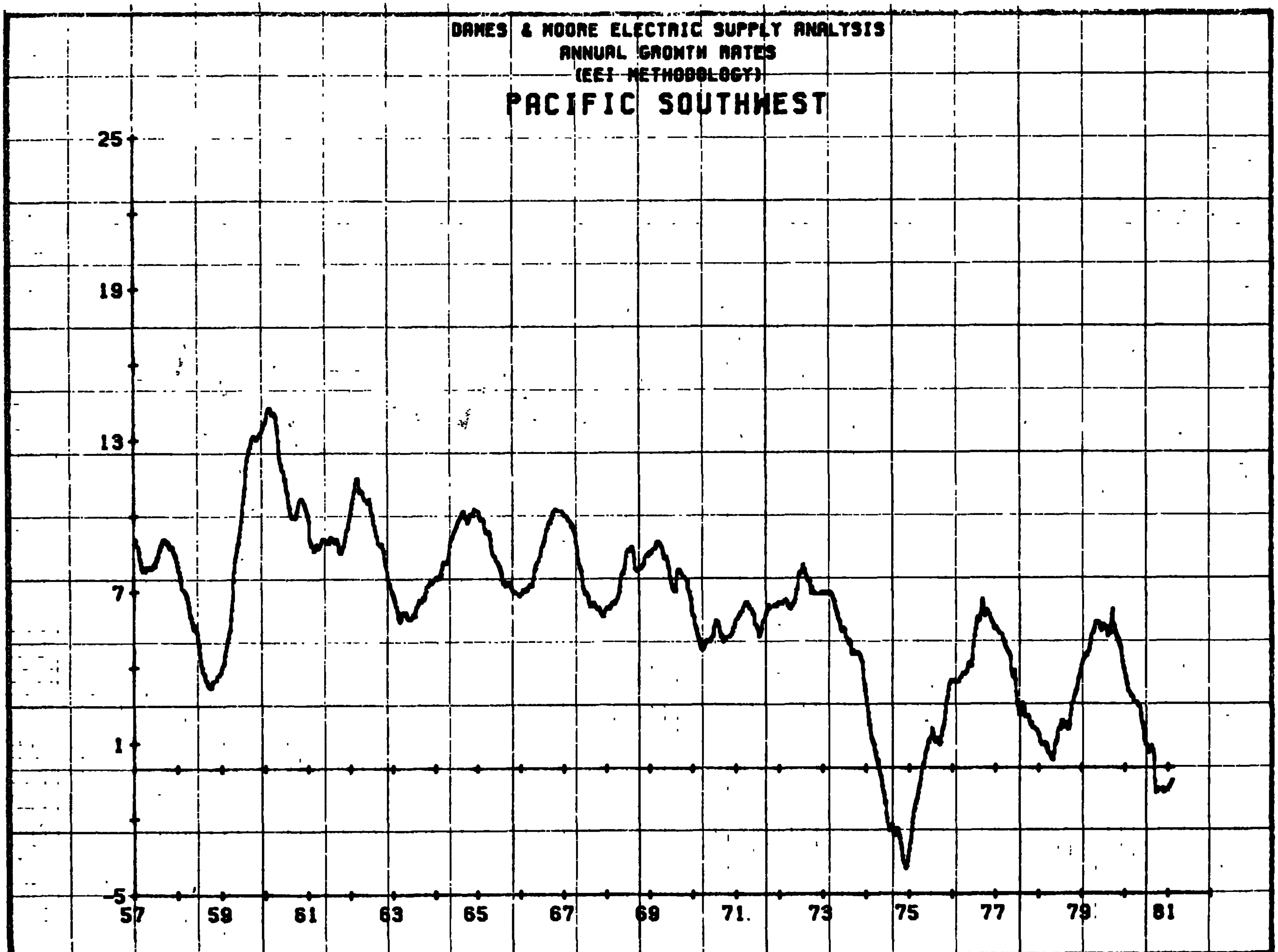

DAMES & MOORE ELECTRIC SUPPLY ANALYSIS
ANNUAL GROWTH RATES
(EEI METHODOLOGY)
PACIFIC SOUTHWEST
25
19
13
7
1
-5
57
59
61
63
65
67
69
71
73
75
77
79
81

EXHIBIT 11

APPENDIX A

INVENTORY OF PUMPED STORAGE FACILITIES IN THE UNITED STATES

CONTENTS

LIST OF TABLES

Appendix A

INVENTORY OF PUMPED STORAGE FACILITIES IN THE UNITED STATES

A.1 PROJECTS

Following is an inventory of pumped storage facilities (either licensed, in construction, or already built) in the United States arranged in alphabetical order; Table A-1, Project Inventory Index, lists the projects in chronological order. The inventory was prepared from a number of sources of available information including:

- Form No. 1: Annual reports to the Federal Energy Regulatory Commission (FERC)
- Form No. 12: Power system statements to the FERC
- Personal communication with facility owners
- Various inventories provided in publications listed in the bibliography.

Table A-2 presents an explanation of notes and abbreviations used.

Section A.2 describes other pumped storage projects that have been discontinued.

TABLE A-1

Project Inventory Index
in Chronological Order by Date of Initial Operation

Project Number	Project Name	Page Number
1	Rocky River	A-67
2	Buchanan	A-16
3	Flatiron	A-32
4	Hiwassee	A-40
5	Lewiston	A-46
6	Taum Sauk	A-77
7	Yards Creek	A-84
8	Smith Mountain	A-75
9	Cabin Creek	A-17
10	Senator Wash	A-74
11	Muddy Run	A-55
12	O'Neill	A-60
13	Thermalito	A-78
14	Edward G. Hyatt	A-28
15	Salina	A-68
16	San Luis	A-70
17	Kinzua	A-44
18	DeGray	A-26
19	Mormon Flat	A-50
20	Horse Mesa	A-41
21	Northfield Mountain	A-57
22	Ludington	A-47
23	Blenheim-Gilboa	A-13
24	Castaic	A-20
25	Grand Coulee	A-33
26	Jocassee	A-42
27	Bear Swamp	A-11
28	Carters	A-18
29	Raccoon Mountain	A-63
30	Fairfield	A-30
31	Wallace	A-82
32	Harry S. Truman	A-37
33	Clarence Cannon	A-21
34	Helms	A-39
35	Bath County	A-9
36	Rocky Mountain	A-65
37	Bad Creek	A-7
38	Montezuma	A-48
39	Davis	A-25
40	Seboyeta	A-72
41	Mt. Elbert	A-51

TABLE A-1 (cont'd)

TABLE A-2

Explanation of Notes and Abbreviations

General

N.A. = Not Applicable

N.D. = Not Determined

U.A. = Unavailable

Type of Reservoir System

Pure developments produce power only from water that has been previously pumped to an upper reservoir.

Combined developments utilize both pumped water and natural streamflow to produce power.

Number & Type of Units

Revs. - Reversible pump-turbine

Conv. - Conventional hydroelectric turbine

Manufacturers

A.C. = Allis Chalmers, BLH = Baldwin-Lima-Hamilton, N.N. = Newport News Shipbuilding and Drydock, W. = Westinghouse, G.E. = General Electric, Nochab = A.B. Hydquist and Holm Aktiebolay, FM = Fairbanks Morse.

Unit capacity is nameplate or estimated nameplate

Output (cfs) is estimated average output using 80% pumping efficiency at average head and average pumping capacity.

Pump Mode Starting Method is as defined by owner.

Number of future units is the number provided for in the present plant.

Storage is based on installed capacity.

Annual Output (MWH) and Annual Pumping Energy (MWH) are given for the most recent year in which these data were available.

FACILITY NAME: Azure | FERC Project Number: 2779

OWNER: Colorado River Water Conservation District

LOCATION: State: Colorado | Status: Preliminary permit application pending

County: U.A.
River: Colorado

TYPE OF RESERVOIR SYSTEM	Pure
CAPITAL COST ($/KW)	U.A.
STORAGE (Hours)	U.A.
NUMBER AND TYPE OF UNITS	2-Revs.
GENERATING:	
Effective Head (ft)	1180
Speed (RPM)	U.A.
Total Capacity (MW)	240
Unit Capacity (MW)	120
Annual Output (MWH)	U.A.
Manufacturer (Turbine/Generator)	U.A.
PUMPING:	
Gross Static Head (ft)	U.A.
Capacity (MW)	240
Output (cfs)	U.A.
Annual Pumping Energy (MWH)	U.A.
PUMP MODE STARTING METHOD	U.A.
DATE OF INITIAL OPERATION (pumped storage only)	U.A.
NUMBER OF FUTURE UNITS	None
ULTIMATE GENERATING CAPACITY (MW)	240

ADDITIONAL DESCRIPTION: The Colorado River Water Conservation District, on August 6, 1976, filed an application with the FERC for a preliminary permit for the proposed two-unit 240-MW Azure pumped storage development on the Colorado River nine miles west of Kremmling, Colorado. The project would include an upper reservoir with a storage capacity of 4,150 acre-feet and an underground powerhouse, and would develop a head of 1,180 feet. The preliminary permit application is still pending.

FACILITY NAME: Bad Creek | FERC Project Number: 2740

OWNER: Duke Power Company

LOCATION: State: South Carolina | Status: Licensed
County: Oconee
River: Bad Creek & West Bad Creek

TYPE OF RESERVOIR SYSTEM	Pure
CAPITAL COST ($/KW)	U.A.
STORAGE (Hours)	32
NUMBER AND TYPE OF UNITS	4-Revs.
GENERATING:	
Effective Head (ft)	1200
Speed (RPM)	U.A.
Total Capacity (MW)	1000
Unit Capacity (MW)	250
Annual Output (MWH)	N.D.
Manufacturer (Turbine/Generator)	U.A.
PUMPING:	
Gross Static Head (ft)	U.A.
Capacity (MW)	1000
Output (cfs)	10,880
Annual Pumping Energy (MWH)	N.D.
PUMP MODE STARTING METHOD	U.A.
DATE OF INITIAL OPERATION (pumped storage only)	1991
NUMBER OF FUTURE UNITS	None
ULTIMATE GENERATING CAPACITY (MW)	1000

ADDITIONAL DESCRIPTION: Duke Power Company, on August 1, 1977, received a license from the Federal Power Commission to construct the four-unit 1,000-MW Bad Creek pumped storage project. It will be located on Bad Creek and West Bad Creek in Oconee County, South Carolina. Dams across these creeks and a saddle dike across a natural depression will create an upper reservoir with a storage capacity of 33,323 acre-feet, of which 30,228 acre-feet will be usable in a drawdown of 160 feet. Lake Jocassee, the upper reservoir of the Jocassee pumped storage development, described in Section 2.2 will be used as the lower reservoir for the Bad Creek Project. The four 250-MW reversible units will be located in an underground powerplant and will operate under a maximum head of about 1,200 feet. The project is not yet under construction but is expected to be operating by January 1991.

FACILITY NAME: Bath County | FERC Project Number: 2716

OWNER: Virginia Electric and Power Co.

LOCATION: State: Virginia
County: Bath
River: Back Creek

Status: Under Construction

TYPE OF RESERVOIR SYSTEM	Pure
CAPITAL COST ($/KW)	U.A.
STORAGE (Hours)	U.A.
NUMBER AND TYPE OF UNITS	6-Revs.
GENERATING:	
Effective Head (ft)	U.A.
Speed (RPM)	U:A.
Total Capacity (MW)	2100
Unit Capacity (MW)	350
Annual Output (MWH)	N.D.
Manufacturer (Turbine/Generator)	U.A.
PUMPING:	
Gross Static Head (ft)	1050
Capacity (MW)	1500
Output (cfs)	18,000
Annual Pumping Energy (MWH)	U.A.
PUMP MODE STARTING METHOD	U.A.
DATE OF INITIAL OPERATION (pumped storage only)	1985
NUMBER OF FUTURE UNITS	None
ULTIMATE GENERATING CAPACITY (MW)	2100

ADDITIONAL DESCRIPTION: When completed the Bath County Project will be the world's largest pumped storage facility. The upper reservoir is being constructed on Little Back Creek and the lower reservoir on Back Creek, tributaries of the Jackson River. The upper reservoir will be created by a 2,200-foot-long zoned rock and earthfill embankment 460 feet high. It will have a surface area of 265 acres and a storage capacity of 35,500 acre-feet. The lower dam will be 135 feet high and 2,400 feet long, constructed of earth and rock fill with an impervious clay core. It will have a surface area of 555 acres and impound 28,000 acre-feet of water, of which 22,500 acre-feet will be usable power storage. The six reversible units will operate under a static head of approximately 1,200 feet.

FACILITY NAME: Bear Swamp FERC Project Number: 2669

OWNER: New England Power Co.

LOCATION: State: Massachusetts
County: Berkshire & Franklin
River: Deerfield

Status: Operating
Completion Date: N.A.

TYPE OF RESERVOIR SYSTEM	Pure
CAPITAL COST ($/KW)	176
STORAGE (Hours)	N.D.
NUMBER AND TYPE OF UNITS	2-Revs.
GENERATING:	
Effective Head (ft)	750-660
Speed (RPM)	225
Total Capacity (MW)	600
Unit Capacity (MW)	300
Annual Output (MWH)	332,712
Manufacturer (Turbine/Generator)	Hitachi/Hitachi
PUMPING:	
Gross Static Head (ft)	770-680
Capacity (MW)	660
Output (cfs)	7,800
Annual Pumping Energy (MWH)	477,190

PUMP MODE STARTING METHOD: Auxiliary starting motors

DATE OF INITIAL OPERATION (pumped storage only)	1974
NUMBER OF FUTURE UNITS	None
ULTIMATE GENERATING CAPACITY (MW)	600

ADDITIONAL
DESCRIPTION: New England Power Company's Bear Swamp development includes two 300-MW reversible units. It is located on the Deerfield River in northwestern Massachusetts. The 4,900 acre-foot upper reservoir was created by rockfill dikes constructed around a natural depression near the crest of a hill along the east bank of the Deerfield River. The lower reservoir was formed by a dam on the Deerfield River at Fife Brook. It has a usable storage capacity of 4,900 acre-feet in a drawdown of 40 feet.

FACILITY NAME: Blenheim - Gilboa FERC Project Number: 2685

OWNER: Power Authority of the State of New York

LOCATION: State: New York Status: Operating
County: Schoharie
River: Schoharie

TYPE OF RESERVOIR SYSTEM	Pure
CAPITAL COST ($/KW)	U.A.
STORAGE (Hours)	12
NUMBER AND TYPE OF UNITS	4-Revs.
GENERATING:	
Effective Head (ft)	1088-1001
Speed (RPM)	257
Total Capacity (MW)	1000
Unit Capacity (MW)	250
Annual Output (MWH)	1,587,655
Manufacturer (Turbine/Generator)	Hitachi/Hitachi
PUMPING:	
Gross Static Head (ft)	1143-1055
Capacity (MW)	1200
Output (cfs)	10,300
Annual Pumping Energy (MWH)	2,379,316

PUMP MODE STARTING METHOD: Auxiliary starting motors

DATE OF INITIAL OPERATION (pumped storage only)	1973
NUMBER OF FUTURE UNITS	None
ULTIMATE GENERATING CAPACITY (MW)	1,000

ADDITIONAL
DESCRIPTION: See Section 2.3.5.

FACILITY NAME: Brumley Gap	FERC Project Number: 2812
OWNER: Appalachian Power Co.	
LOCATION: State: Virginia	Status: Application for preliminary permit pending
County: Washington	
River: Brumley Creek	

TYPE OF RESERVOIR SYSTEM	Pure	
CAPITAL COST ($/KW)	U.A.	
STORAGE (Hours)	U.A.	
NUMBER AND TYPE OF UNITS		Revs.
GENERATING:		
Effective Head (ft)		U.A.
Speed (RPM)		U.A.
Total Capacity (MW)		3000
Unit Capacity (MW)		U.A.
Annual Output (MWH)		U.A.
Manufacturer (Turbine/Generator)		U.A.
PUMPING:		
Gross Static Head (ft)		U.A.
Capacity (MW)		3000
Output (cfs)		U.A.
Annual Pumping Energy (MWH)		U.A.
PUMP MODE STARTING METHOD		U.A.
DATE OF INITIAL OPERATION (pumped storage only)		U.A.
NUMBER OF FUTURE UNITS		U.A.
ULTIMATE GENERATING CAPACITY (MW)		U.A.

ADDITIONAL DESCRIPTION: On August 30, 1977, the Appalachian Power Company filed an application for preliminary permit with the FERC for its proposed Brumley Gap Project that would be located on Brumley Creek at Brumley Gap, Virginia. This pure pumped storage development would have an upper dam impounding a reservoir with a surface area of 620 acres at full pool elevation of 3,720 feet, a lower dam and saddle dike impounding a reservoir with a surface area of 1,335 acres at full pool elevation of 1,880 feet, and an underground powerhouse with a capacity up to 3,000 MW. The estimated average annual generation is seven billion kilowatt-hours. The FERC has received many letters opposing construction of the project and nine petitions to intervene. The staff of the FERC prepared an Environmental Assessment on the application and made a finding that activities to be conducted under a preliminary permit would not constitute a major Federal action significantly affecting the quality of the human environment. Action on the application is still pending.

FACILITY NAME: Buchanan FERC Project Number: N.A.

OWNER: Lower Colorado River Authority

LOCATION: State: Texas Status: Operating
County: Llano & Burnet
River: Colorado

TYPE OF RESERVOIR SYSTEM	Combined	
CAPITAL COST ($/KW)	U.A.	
STORAGE (Hours)	U.A.	
NUMBER AND TYPE OF UNITS	Revs.	Conv.
GENERATING:		
Effective Head (ft)	U.A.	U.A.
Speed (RPM)	U.A.	U.A.
Total Capacity (MW)	11	23
Unit Capacity (MW)	U.A.	U.A.
Annual Output (MWH)	U.A.	U.A.
Manufacturer (Turbine/Generator)	U.A.	U.A.
PUMPING:		
Gross Static Head (ft)	U.A.	
Capacity (MW)	U.A.	
Output (cfs)	U.A.	
Annual Pumping Energy (MWH)	U.A.	
PUMP MODE STARTING METHOD	U.A.	
DATE OF INITIAL OPERATION (pumped storage only)	1950	
NUMBER OF FUTURE UNITS	U.A.	
ULTIMATE GENERATING CAPACITY (MW)	U.A.	

FACILITY NAME: Cabin Creek FERC Project Number: 2331

OWNER: Public Service Co. of Colorado

LOCATION: State: Colorado Status: Operating
County: Clear Creek
River: Clear Creek

TYPE OF RESERVOIR SYSTEM	Pure
CAPITAL COST ($/KW)	113
STORAGE (Hours)	5
NUMBER AND TYPE OF UNITS	2-Revs.
GENERATING:	
Effective Head (ft)	1190-975
Speed (RPM)	360
Total Capacity (MW)	300
Unit Capacity (MW)	150
Annual Output (MWH)	208,854
Manufacturer (Turbine/Generator)	A.C./G.E.
PUMPING:	
Gross Static Head (ft)	1226-1170
Capacity (MW)	300
Output (cfs)	2,500
Annual Pumping Energy (MWH)	401,866

PUMP MODE STARTING METHOD: Auxiliary starting motors

DATE OF INITIAL OPERATION (pumped storage only)	1966
NUMBER OF FUTURE UNITS	None
ULTIMATE GENERATING CAPACITY (MW)	300

FACILITY NAME: Carters

FERC Project Number: N.A.

OWNER: Corps of Engineers

LOCATION: State: Georgia
County: Murray
River: Coosawatte

Status: Operating

TYPE OF RESERVOIR SYSTEM	Combined	
CAPITAL COST ($/KW)	210	
STORAGE (Hours)	44	
NUMBER AND TYPE OF UNITS	2-Revs.	2-Conv.
GENERATING:		
Effective Head (ft)	388-346	427-320
Speed (RPM)	150	163.6
Total Capacity (MW)	250	250
Unit Capacity (MW)	125	125
Annual Output (MWH)	516,288	N.A.
Manufacturer (Turbine/Generator)	A.C./G.E.	N.N./A.C.
PUMPING:		
Gross Static Head (ft)	392-352	
Capacity (MW)	276	
Output (cfs)	8,860	
Annual Pumping Energy (MWH)	335,436	

PUMP MODE STARTING METHOD: Reduced frequency

DATE OF INITIAL OPERATION (pumped storage only)	1975
NUMBER OF FUTURE UNITS	None
ULTIMATE GENERATING CAPACITY (MW)	500

ADDITIONAL DESCRIPTION: Carters Reservoir was created by a rockfill dam 485 feet high. The powerhouse contains two 125-MW conventional units and two 125-MW reversible units. The lower reservoir is formed by a reregulation dam approximately 1.8 miles downstream from the main dam. It comprises a concrete gated spillway and composite rock-and-earth dikes.

FACILITY NAME: Castaic FERC Project Number: 2426

OWNER: Los Angeles City & State of California

LOCATION: State: California Status: Operating
County: Los Angeles
River: California Aqueduct

TYPE OF RESERVOIR SYSTEM	Combined	
CAPITAL COST ($/KW)	236	
STORAGE (Hours)	14.64	
NUMBER AND TYPE OF UNITS	6-Revs.	1-Conv.
GENERATING:		
Effective Head (ft)	957-891	957-891
Speed (RPM)	257	225
Total Capacity (MW)	1275	56
Unit Capacity (MW)	212.5	56
Annual Output (MWH)	656,316	N.A.
Manufacturer (Turbine/Generator)	Hitachi/ASEA	Kacher Wyss/ Toshiba
PUMPING:		
Gross Static Head (ft)	1088-1022	
Capacity (MW)	1,250	
Output (cfs)	11,300	
Annual Pumping Energy (MWH)	495,948	
PUMP MODE STARTING METHOD:	Reduced frequency	
DATE OF INITIAL OPERATION (pumped storage only)	1973*	
NUMBER OF FUTURE UNITS	None	
ULTIMATE GENERATING CAPACITY (MW)	1331	

*1 unit 1973, 1 unit 1974, 1 unit 1976, 1 unit 1977, 2 units 1978.

FACILITY NAME: Clarence Cannon　　FERC Project Number: N.A.

OWNER: Corps of Engineers

LOCATION: State: Missouri　　Status: Under construction
County: Lewis
River: Salt River

TYPE OF RESERVOIR SYSTEM	Combined	
CAPITAL COST ($/KW)	N.D.	
STORAGE (Hours)	8	
NUMBER AND TYPE OF UNITS	Revs.	Conv.
GENERATING:		
Effective Head (ft)	U.A.	U.A.
Speed (RPM)	75	U.A.
Total Capacity (MW)	31	27
Unit Capacity (MW)	U.A.	U.A.
Annual Output (MWH)	N.A.	N.A.
Manufacturer (Turbine/Generator)	A.C./G.E.	
PUMPING:		
Gross Static Head (ft)	107-59	
Capacity (MW)	31	
Output (cfs)	12,000	
Annual Pumping Energy (MWH)	N.A.	
PUMP MODE STARTING METHOD	Synchronous start from another unit	
DATE OF INITIAL OPERATION (pumped storage only)	1983	
NUMBER OF FUTURE UNITS	None	
ULTIMATE GENERATING CAPACITY (MW)	58	

ADDITIONAL DESCRIPTION: The Clarence Cannon Dam and Reservoir is being constructed on the Salt River, a tributary of the Mississippi River. This multipurpose pumped storage project is about 125 miles northwest of St. Louis. The dam rises 138 feet above streambed and creates an 18,600-acre lake. A reregulation dam, 9.5 miles downstream, creates the lower reservoir for pumped storage operations. The powerplant, to house one 27-MW conventional unit and one 31-MW reversible unit, is expected to be operational in 1983.

FACILITY NAME: Cornwall FERC Project Number: 2338

OWNER: Consolidated Edison Co. of New York, Inc.

LOCATION: State: New York Status: Under litigation
County: Orange
River: Hudson

TYPE OF RESERVOIR SYSTEM	Pure
CAPITAL COST ($/KW)	U.A.
STORAGE (Hours)	U.A.
NUMBER AND TYPE OF UNITS	8-Revs.
GENERATING:	
Effective Head (ft)	U.A.
Speed (RPM)	257
Total Capacity (MW)	2,000
Unit Capacity (MW)	250
Annual Output (MWH)	N.D.
Manufacturer (Turbine/Generator)	U.A./U.A.
PUMPING:	
Gross Static Head (ft)	1160-1000
Capacity (MW)	2,000
Output (cfs)	18,000
Annual Pumping Energy (MWH)	N.D.

PUMP MODE STARTING METHOD: Auxiliary starting motors

DATE OF INITIAL OPERATION (pumped storage only)	1991*
NUMBER OF FUTURE UNITS	4
ULTIMATE GENERATING CAPACITY (MW)	3000

---

*Estimated

ADDITIONAL DESCRIPTION: The Cornwall Project was designed to have an initial installation of 2,000 MW (eight 250-MW units) with minimum facilities being included to include possible future expansion to 3,000 MW. The upper reservoir was to be located behind Storm King Mountain and have a usable storage capacity of about 25,000 acre-feet in 160 feet of drawdown. The lower reservoir was to be the Hudson River which, at Cornwall, is essentially an estuary of the Atlantic Ocean with small, semi-diurnal tides, and water of low saline content. The river's width is in excess of one mile so the lower reservoir would provide unlimited storage capacity. The gross static head would be 1,160 feet.

FACILITY NAME: Davis FERC Project Number: 2709

OWNER: Monongahela Power, Potomac Edison, West Penn Power

LOCATION: State: West Virginia Status: Licensed
County: Tucker
River: Blackwater

TYPE OF RESERVOIR SYSTEM	Pure
CAPITAL COST ($/KW)	U.A.
STORAGE (Hours)	U.A.
NUMBER AND TYPE OF UNITS	4-Revs.
GENERATING:	
Effective Head (ft)	U.A.
Speed (RPM)	U.A.
Total Capacity (MW)	1025
Unit Capacity (MW)	U.A.
Annual Output (MWH)	N.D.
Manufacturer (Turbine/Generator)	U.A./U.A.
PUMPING:	
Gross Static Head (ft)	864-803
Capacity (MW)	1000
Output (cfs)	U.A.
Annual Pumping Energy (MWH)	N.D.
PUMP MODE STARTING METHOD	U.A.
DATE OF INITIAL OPERATION (pumped storage only)	1988*
NUMBER OF FUTURE UNITS	None
ULTIMATE GENERATING CAPACITY (MW)	1025

*Estimated

FACILITY NAME: DeGray

FERC Project Number: N.A.

OWNER: Corps of Engineers

LOCATION: State: Arkansas
County: Clark
River: Caddo

Status: Operating

TYPE OF RESERVOIR SYSTEM	Combined	
CAPITAL COST ($/KW)	N.D.	
STORAGE (Hours)	N.D.	
NUMBER AND TYPE OF UNITS	1-Revs.	1-Conv.
GENERATING:		
Effective Head (ft)	U.A.	U.A.
Speed (RPM)	128.5	150
Total Capacity (MW)	28	40
Unit Capacity (MW)	28	40
Annual Output (MWH)	U.A.	
Manufacturer (Turbine/Generator)	N.N./A.C.	U.A.
PUMPING:		
Gross Static Head (ft)	188-144	
Capacity (MW)	U.A.	
Output (cfs)	600	
Annual Pumping Energy (MWH)	N.A.*	

PUMP MODE STARTING METHOD: Synchronous start from another unit, variable frequency and voltage

DATE OF INITIAL OPERATION (pumped storage only) 1971

NUMBER OF FUTURE UNITS 1

ULTIMATE GENERATING CAPACITY (MW) 96

*Not used for pump storage, used as spinning reserve.

ADDITIONAL DESCRIPTION: The DeGray Plant is on the Caddo River near Arkadelphia, Arkansas, and is operated remotely from a control center in Blakely Mountain Dam about 50 miles to the north. It consists of a 40-MW conventional unit and a 28-MW reversible unit. The two units are designed so that the conventional unit can be used to start the pump unit. The procedure involves using the energy of the conventional unit to bring the pump unit to speed in air after which the air is released, priming the pump, the gates are opened, and the pump/turbine unit synchronized to the line.

FACILITY NAME: Edward G. Hyatt FERC Project Number: 2100

OWNER: California Department of Water Resources

LOCATION: State: California Status: Operating
County: Butte
River: Feather

TYPE OF RESERVOIR SYSTEM	Combined	
CAPITAL COST ($/KW)	U.A.	
STORAGE (Hours)	N.A.	
NUMBER AND TYPE OF UNITS	3-Revs.	3-Conv.
GENERATING:		
Effective Head (ft)	663-502	675-500
Speed (RPM)	189	200
Total Capacity (MW)	293	351
Unit Capacity (MW)	97.8	117
Annual Output (MWH)	2,041,095	N.A.
Manufacturer (Turbine/Generator)	A.C./W.	A.C./W.
PUMPING:		
Gross Static Head (ft)	670-508	
Capacity (MW)	387	
Output (cfs)	6,240	
Annual Pumping Energy (MWH)	102,195	
PUMP MODE STARTING METHOD:	Reduced frequency	
DATE OF INITIAL OPERATION (pumped storage only)	1968	
NUMBER OF FUTURE UNITS	None	
ULTIMATE GENERATING CAPACITY (MW)	293	

ADDITIONAL DESCRIPTION: Both the Edward G. Hyatt and Thermalito Powerplants are part of the California Water Project constructed and operated by the California Department of Water Resources. The primary purpose of the project is to convey surplus water from northern California to areas of need in central and southern California. The key construction feature is 770-foot-high Oroville Dam on the Feather River which creates a reservoir with a storage capacity of 3,484,000 acre-feet. The 644-MW Edward G. Hyatt underground powerplant located at Oroville Dam contains three 117-MW conventional and three 97.8-MW reversible units. Downstream from the Oroville Dam is the Thermalito Diversion Dam that serves the dual function of creating the lower reservoir for the Edward G. Hyatt reversible units and diverting the Feather River into the Thermalito Canal. Water discharged from Oroville Reservoir is used for power generation in both the Edward G. Hyatt and Thermalito powerplants and is returned from the Thermalito Afterbay to Oroville Reservoir by pumping, using the reversible turbines in the two plants.

FACILITY NAME: Fairfield | FERC Project Number: 1894

OWNER: South Carolina Electric & Gas Co.

LOCATION: State: South Carolina | Status: Operating
County: Fairfield
River: Broad

TYPE OF RESERVOIR SYSTEM	Pure
CAPITAL COST ($/KW)	390
STORAGE (Hours)	8
NUMBER AND TYPE OF UNITS	8-Revs.
GENERATING:	
Effective Head (ft)	U.A.
Speed (RPM)	150
Total Capacity (MW)	511.2
Unit Capacity (MW)	63.9
Annual Output (MWH)	447,709
Manufacturer (Turbine/Generator)	A.C./A.C.
PUMPING:	
Gross Static Head (ft)	169-155
Capacity (MW)	480
Output (cfs)	U.A.
Annual Pumping Energy (MWH)	628,698
PUMP MODE STARTING METHOD:	Reduced voltage
DATE OF INITIAL OPERATION (pumped storage only)	1979
NUMBER OF FUTURE UNITS	None
ULTIMATE GENERATING CAPACITY (MW)	511.2

ADDITIONAL DESCRIPTION: South Carolina Electric and Gas Company's Fairfield pumped storage plant contains eight 63.9 MW units that utilize an average head of 155 feet. The project is on the Broad River in Newberry and Fairfield Counties, South Carolina. The lower reservoir was created by increasing the height of the company's Parr Dam on the Broad River by 10 feet. Monticello, the upper reservoir, was created by an earth-fill dam about 180 feet high across Frees Creek and three smaller saddle dams. It has a gross storage capacity of 400,000 acre-feet, and provides cooling water for the company's V.C. Summer nuclear powerplant.

FACILITY NAME: Flatiron* FERC Project Number: N.A.

OWNER: Water and Power Resources Service

LOCATION: State: Colorado Status: Operating
County: Larimer
River: Carter Lake

TYPE OF RESERVOIR SYSTEM	Combined	
CAPITAL COST ($/KW)	485	
STORAGE (Hours)	4000	
NUMBER AND TYPE OF UNITS	8-Revs.	2-Conv.
GENERATING:		
Effective Head (ft)	U.A.	U.A.
Speed (RPM)	U.A.	U.A.
Total Capacity (MW)	480	63
Unit Capacity (MW)	60	31.5
Annual Output (MWH)	U.A.	U.A.
Manufacturer (Turbine/Generator)	A.C./A.C.	U.A.
PUMPING:		
Gross Static Head (ft)	290-140	
Capacity (MW)	U.A.	
Output (cfs)	370	
Annual Pumping Energy (MWH)	U.A.	
PUMP MODE STARTING METHOD	Across the line, full voltage	
DATE OF INITIAL OPERATION (pumped storage only)	1954	
NUMBER OF FUTURE UNITS	U.A.	
ULTIMATE GENERATING CAPACITY (MW)	U.A.	

*Flatiron is a pumped storage unit but is not used strictly for this purpose but for distribution of irrigation water.

FACILITY NAME: Grand Coulee FERC Project Number: N.A.

OWNER: Water and Power Resources Service

LOCATION: State: Washington Status: Operating
County: Grant & Okanogan
River: Columbia

TYPE OF RESERVOIR SYSTEM	Pure
CAPITAL COST ($/KW)	U.A.
STORAGE (Hours)	572
NUMBER AND TYPE OF UNITS	6-Revs.
GENERATING:	
Effective Head (ft)	358-262
Speed (RPM)	200
Total Capacity (MW)	314
Unit Capacity (MW)	53.5/50*
Annual Output (MWH)	U.A.
Manufacturer (Turbine/Generator)	Nohab/W.
PUMPING:	
Gross Static Head (ft)	362-266
Capacity (MW)	100
Output (cfs)	2,500
Annual Pumping Energy (MWH)	U.A.
PUMP MODE STARTING METHOD:	Across the line
DATE OF INITIAL OPERATION (pumped storage only)	1973
NUMBER OF FUTURE UNITS	6
ULTIMATE GENERATING CAPACITY (MW)	535

*2 units at 50 and 4 units at 53.5.

ADDITIONAL DESCRIPTION: Six 65,000-horsepower pumps had been installed on the Grand Coulee site by 1951 to serve initial irrigation development on the Columbia Basin Project; the ultimate installation will comprise 12 units having a total pumping capacity of 16,200 cfs under a dynamic head of 310 feet. Water is pumped from the Columbia River to Banks Lake, a 27-mile-long reservoir with an active storage capacity of 761,800 acre-feet. The first two generating units, rated at 50 MW each, were installed in 1973. Four units rated at 53.3 MW each are scheduled for completion by 1980.

FACILITY NAME: Gregory County | FERC Project Number: N.A.

OWNER: Corps of Engineers

LOCATION: State: South Dakota | Status: Under study
County: Gregory
River: Missouri

TYPE OF RESERVOIR SYSTEM	Pure
CAPITAL COST ($/KW)	U.A.
STORAGE (Hours)	U.A.
NUMBER AND TYPE OF UNITS	3-Revs.
GENERATING:	
Effective Head (ft)	U.A.
Speed (RPM)	U.A.
Total Capacity (MW)	1179.9
Unit Capacity (MW)	393.3
Annual Output (MWH)	U.A.
Manufacturer (Turbine/Generator)	U.A.
PUMPING:	
Gross Static Head (ft)	711
Capacity (MW)	U.A.
Output (cfs)	16,500
Annual Pumping Energy (MWH)	U.A.
PUMP MODE STARTING METHOD	U.A.
DATE OF INITIAL OPERATION (pumped storage only)	U.A.
NUMBER OF FUTURE UNITS	U.A.
ULTIMATE GENERATING CAPACITY (MW)	U.A.

ADDITIONAL DESCRIPTION: In 1977, the Missouri River Division of the Corps of Engineers completed a report entitled "Missouri River, South Dakota, Nebraska, North Dakota, Montana Review Report for Water Resources Development." One of the recommendations in the report was that the Corps of Engineers be authorized to conduct the first phase of advanced engineering and design studies of a pumped storage facility in Gregory County, South Dakota. The 1977 report was returned by the Secretary of the Army for additional studies of the potential Gregory County pumped storage project. Those studies have been initiated by the Corps' Omaha District and an interim report is expected to be completed in fiscal year 1981. The project would be located adjacent to the west side of the existing Lake Francis Case, created by the Fort Randall Dam, about three miles south of the Plotte-Winner Bridge in Gregory County, South Dakota. The three-unit powerplant would have a total capacity of 1,180 MW and the gross head of the project would average 711 feet. The upper reservoir would have a surface area of 1,155 acres, a gross storage capacity of 47,100 acre-feet, and an active storage capacity of 46,800 acre-feet. The project would operate on a weekly cycle and would generate about nine hours each day Monday through Friday, with no generation on weekends. Pumpback would occur 8.3 hours per day on weekdays and 13 hours per day on weekends. The planned weekly cycle of operation would affect the elevation of Lake Francis Case a maximum of only 5.4 inches.

FACILITY NAME: Harry S. Truman

FERC Project Number: N.A.

OWNER: Corps of Engineers

LOCATION: State: Missouri
County: Miller
River: Osage

Status: Under Construction

TYPE OF RESERVOIR SYSTEM	Pure
CAPITAL COST ($/KW)	U.A.
STORAGE (Hours)	U.A.
NUMBER AND TYPE OF UNITS	6-Revs.
GENERATING:	
Effective Head (ft)	79-41
Speed (RPM)	100
Total Capacity (MW)	160
Unit Capacity (MW)	26.7
Annual Output (MWH)	N.D.
Manufacturer (Turbine/Generator)	BLH/U.D.
PUMPING:	
Gross Static Head (ft)	U.A.
Capacity (MW)	163
Output (cfs)	22,500
Annual Pumping Energy (MWH)	N.D.

PUMP MODE STARTING METHOD: Across the line synchronous starting with only five units pumping

DATE OF INITIAL OPERATION (pumped storage only)	1981
NUMBER OF FUTURE UNITS	None
ULTIMATE GENERATING CAPACITY (MW)	160

ADDITIONAL DESCRIPTION: The Harry S. Truman Dam is on the Osage River at the headwaters of the Lake of the Ozarks, a reservoir created by the Union Electric Company's Bagnell Dam. The Truman Reservoir has a normal operating area of 55,600 acres, but an area of 209,300 acres at full flood control pool. The six-unit 160-MW pumped storage plant will utilize the Lake of the Ozarks as an afterbay. Reversible tube-type pump/turbines have been installed because the net operating head will be relatively low, ranging from 41 to 74.2 feet. The units were undergoing tests in 1980 but were not expected to be in commercial operation prior to 1981.

FACILITY NAME: Helms FERC Project Number: 2733

OWNER: Pacific Gas and Electric Company

LOCATION: State: California Status: Under Construction
County: Tulare
River: W. Fork Kings River and Helms Creek

TYPE OF RESERVOIR SYSTEM	Pure
CAPITAL COST ($/KW)	571*
STORAGE (Hours)	U.A.
NUMBER AND TYPE OF UNITS	3-Revs.
GENERATING:	
Effective Head (ft)	U.A.
Speed (RPM)	360
Total Capacity (MW)	1050
Unit Capacity (MW)	350
Annual Output (MWH)	N.D.
Manufacturer (Turbine/Generator)	Hitachi/Westinghouse
PUMPING:	
Gross Static Head (ft)	1560
Capacity (MW)	1,035
Output (cfs)	7,200
Annual Pumping Energy (MWH)	N.D.
PUMP MODE STARTING METHOD	U.A.
DATE OF INITIAL OPERATION (pumped storage only)	1983
NUMBER OF FUTURE UNITS	None
ULTIMATE GENERATING CAPACITY (MW)	1050

ADDITIONAL
DESCRIPTION: See Section 2.3.4.

---

*Estimated

FACILITY NAME: Hiwassee FERC Project Number: N.A.

OWNER: Tennessee Valley Authority

LOCATION: State: North Carolina Status: Operating
County: Cherokee
River: Hiwassee

TYPE OF RESERVOIR SYSTEM	Combined	
CAPITAL COST ($/KW)	77	
STORAGE (Hours)	U.A.	
NUMBER AND TYPE OF UNITS	1-Revs.	1-Conv.
GENERATING:		
Effective Head (ft)	U.A.	U.A.
Speed (RPM)	105.9	120
Total Capacity (MW)	60	57
Unit Capacity (MW)	60	57
Annual Output (MWH)	U.A.	U.A.
Manufacturer (Turbine/Generator)	A.C./A.C.	N.N./W.
PUMPING:		
Gross Static Head (ft)	243-134	
Capacity (MW)	76	
Output (cfs)	3,800	
Annual Pumping Energy (MWH)	U.A.	
PUMP MODE STARTING METHOD	Across the line-reduced voltage	
DATE OF INITIAL OPERATION (pumped storage only)	1956	
NUMBER OF FUTURE UNITS	U.A.	
ULTIMATE GENERATING CAPACITY (MW)	U.A.	

FACILITY NAME: Horse Mesa

FERC Project Number: N.A.

OWNER: Salt River Project Power District

LOCATION: State: Arizona
County: Maricopa
River: Salt

Status: Operating

TYPE OF RESERVOIR SYSTEM	Combined	
CAPITAL COST ($/KW)	169	
STORAGE (Hours)	8	
NUMBER AND TYPE OF UNITS	1-Revs.	3-Conv.
GENERATING:		
Effective Head (ft)	259-151	259-151
Speed (RPM)	150	300
Total Capacity (MW)	100	30
Unit Capacity (MW)	100	10
Annual Output (MWH)	243,847	
Manufacturer (Turbine/Generator)	BLH/W.	U.A./U.A.
PUMPING:		
Gross Static Head (ft)	295-151	
Capacity (MW)	85	
Output (cfs)	4,100	
Annual Pumping Energy (MWH)	58,320	

PUMP MODE STARTING METHOD: Auxiliary starting motors

DATE OF INITIAL OPERATION (pumped storage only)	1972
NUMBER OF FUTURE UNITS	U.A.
ULTIMATE GENERATING CAPACITY (MW)	U.A.

FACILITY NAME: Jocassee — FERC Project Number: 2503

OWNER: Duke Power Co.

LOCATION: State: South Carolina & North Carolina — Status: Operating
County: Pickens & Transylvania
River: Keowee

TYPE OF RESERVOIR SYSTEM	Combined
CAPITAL COST ($/KW)	170
STORAGE (Hours)	192
NUMBER AND TYPE OF UNITS	4-Revs.
GENERATING:	
Effective Head (ft)	331-276
Speed (RPM)	120
Total Capacity (MW)	610
Unit Capacity (MW)	152.5
Annual Output (MWH)	587,846
Manufacturer (Turbine/Generator)	A.C./W.
PUMPING:	
Gross Static Head (ft)	335-280
Capacity (MW)	610
Output (cfs)	19,100
Annual Pumping Energy (MWH)	596,931

PUMP MODE STARTING METHOD: 3 units reduced frequency, 1 unit reduced frequency

DATE OF INITIAL OPERATION (pumped storage only)	1974
NUMBER OF FUTURE UNITS	None
ULTIMATE GENERATING CAPACITY (MW)	610

ADDITIONAL
DESCRIPTION: The four-unit plant has a total capacity of 610 MW. The Jocassee Reservoir has a gross storage capacity of 1,143,000 acre-feet and a usable storage capacity of 214,000 acre-feet in 30 feet of drawdown. Lake Keowee provides the lower reservoir. It was created by two earthfill dams and five saddle dikes, and has a total storage capacity of 911,000 acre-feet. Lake Keowee provides cooling water for the three-unit Oconee Nuclear Station and is the source of water for the 140-MW conventional Keowee hydroelectric plant.

FACILITY NAME: Kinzua ° FERC Project Number: 2280

OWNERS: Cleveland Electric Illuminating Co.
Pennslyvania Electric Co.

LOCATION: State: Pennsylvania Status: Operating
County: Warren
River: Allegheny

TYPE OF RESERVOIR SYSTEM	Pure*	
CAPITAL COST ($/KW)	155	
STORAGE (Hours)	10.3	
NUMBER AND TYPE OF UNITS	2-Revs.	1 conv.
GENERATING:		
Effective Head (ft)	791-642	U.A.
Speed (RPM)	225	514
Total Capacity (MW)	396	26
Unit Capacity (MW)	198	26
Annual Output (MWH)	538,904	U.S.
Manufacturer (Turbine/Generator)	N.N./W.	BLH
PUMPING:		
Gross Static Head (ft)	813-668	N.A.
Capacity (MW)	396	N.A.
Output (cfs)	4,970	N.A.
Annual Pumping Energy (MWH)	742,241	N.A.

PUMP MODE STARTING METHOD: Reduced frequency

DATE OF INITIAL OPERATION (pumped storage only) 1970

NUMBER OF FUTURE UNITS None

ULTIMATE GENERATING CAPACITY (MW) 422

ADDITIONAL DESCRIPTION: The Kinzua pumped storage project utilizes the Corps of Engineers' Allegheny Reservoir on the Allegheny River in western Pennsylvania as the lower reservoir while a 106-acre offstream reservoir above the left abutment of the Corps' dam serves as the upper. The upper reservoir was created by the construction of a dike formed from sandstone excavated from the floor of the reservoir. The dike has a maximum height of about 112 feet and its inside face and the entire floor of the reservoir are covered with an impervious asphaltic membrane. A concrete and steel lined tunnel, 19 feet in diameter, extends from a bellmouth intake in the floor of the upper reservoir a distance of about 2,400 feet to two bifurcations and three short penstocks leading to three generating units. Two units have reversible pump/turbines and have a total rated generating capacity of 396 MW. One of the reversible units has a divided draft tube so that it may discharge either into the Allegheny Reservoir or into the Allegheny River below the dam. The other reversible unit discharges only into the reservoir. A 26-MW conventional unit discharges directly into the Allegheny River downstream from the dam.

FACILITY NAME: Lewiston FERC Project Number: 2216

OWNER: Power Authority of the State of New York

LOCATION: State: New York
County: Niagara
River: Niagara

Status: Operating

TYPE OF RESERVOIR SYSTEM	Pure
CAPITAL COST ($/KW)	203
STORAGE (Hours)	U.A.
NUMBER AND TYPE OF UNITS	12-Revs.
GENERATING:	
Effective Head (ft)	U.A.
Speed (RPM)	112.5
Total Capacity (MW)	240
Unit Capacity (MW)	20
Annual Output (MWH)	361,043
Manufacturer (Turbine/Generator)	A.C./A.C.
PUMPING:	
Gross Static Head (ft)	100-65
Capacity (MW)	336
Output (cfs)	38,000
Annual Pumping Energy (MWH)	609,867
PUMP MODE STARTING METHOD	Across the line
DATE OF INITIAL OPERATION (pumped storage only)	1962
NUMBER OF FUTURE UNITS	None
ULTIMATE GENERATING CAPACITY (MW)	240

FACILITY NAME: Ludington FERC Project Number: 2680

OWNER: Consumers Power Co., Detroit Edison Co.

LOCATION: State: Michigan
County: Mason
River: Lake Michigan

Status: Operating

TYPE OF RESERVOIR SYSTEM	Pure
CAPITAL COST ($/KW)	156
STORAGE (Hours)	8.7
NUMBER AND TYPE OF UNITS	6-Revs.
GENERATING:	
Effective Head (ft)	U.A.
Speed (RPM)	112.5
Total Capacity (MW)	1978.8
Unit Capacity (MW)	329.8
Annual Output (MWH)	2,325,690
Manufacturer (Turbine/Generator)	Hitachi/Hitachi
PUMPING:	
Gross Static Head (ft)	362.5-295.5
Capacity (MW)	1920
Output (cfs)	58,200
Annual Pumping Energy (MWH)	3,261,234

PUMP MODE STARTING METHOD: 4 units reduced frequency, 2 units reduced voltage

DATE OF INITIAL OPERATION (pumped storage only)	1973
NUMBER OF FUTURE UNITS	None
ULTIMATE GENERATING CAPACITY (MW)	1,978.8

ADDITIONAL
DESCRIPTION: See Section 2.3.3.

FACILITY NAME: Montezuma FERC Project Number: 2573

OWNER: Arizona Power Authority

LOCATION: State: Arizona
County: Maricopa & Pinal
River: N.A.

Status: Under construction

TYPE OF RESERVOIR SYSTEM	Pure
CAPITAL COST ($/KW)	N.D.
STORAGE (Hours)	U.A.
NUMBER AND TYPE OF UNITS	4-Revs.
GENERATING:	
Effective Head (ft)	U.A.
Speed (RPM)	600
Total Capacity (MW)	505.4
Unit Capacity (MW)	126.4
Annual Output (MWH)	N.D.
Manufacturer (Turbine/Generator)	U.A./U.A.
PUMPING:	
Gross Static Head (ft)	1690-1620
Capacity (MW)	500
Output (cfs)	3,000
Annual Pumping Energy (MWH)	N.D.

PUMP MODE STARTING METHOD: Auxiliary starting motors

DATE OF INITIAL OPERATION (pumped storage only)	1988*
NUMBER OF FUTURE UNITS	None
ULTIMATE GENERATING CAPACITY (MW)	505.4

*Estimated

ADDITIONAL
DESCRIPTION: The Montezuma project would be located on lands of the Gila River Indian Reservation about 20 miles southwest of Phoenix and adjacent to the Sierra Estrella Mountains in Maricopa and Pinal counties, Arizona. The project would neither be located upon nor utilize any permanent stream. Water needed by the project would be obtained by pumping from wells. The project would be the highest head reversible pumped storage development in the United States, having a maximum static head of 1,690 feet. The upper reservoir would be created by a dam across a horeshoe-shaped valley in the Sierra Estrella Mountains. The lower reservoir would be created by a rockfill dam. No spillway would be required because the natural drainage area would be negligible. However, the entire reservoir would require lining to prevent leakage.

FACILITY NAME: Mormon Flat | FERC Project Number: N.A.

OWNER: Salt River Project Power District

LOCATION: State: Arizona | Status: Operating
County: Maricopa
River: Salt

TYPE OF RESERVOIR SYSTEM	Combined	
CAPITAL COST ($/KW)	276	
STORAGE (Hours)	11	
NUMBER AND TYPE OF UNITS	1-Revs.	1-Conv.
GENERATING:		
Effective Head (ft)	N.A.	N.A.
Speed (RPM)	138.5	225
Total Capacity (MW)	49	9
Unit Capacity (MW)	49	9
Annual Output (MWH)	84,330	N.A.
Manufacturer (Turbine/Generator)	A.C./A.C.	U.A.
PUMPING:		
Gross Static Head (ft)	132	
Capacity (MW)	50	
Output (cfs)	4,000	
Annual Pumping Energy (MWH)	59,625	

PUMP MODE STARTING METHOD: Across the line-reduced voltage

DATE OF INITIAL OPERATION (pumped storage only)	1971
NUMBER OF FUTURE UNITS	None
ULTIMATE GENERATING CAPACITY (MW)	49

FACILITY NAME: Mt. Elbert FERC Project Number: N.A.

OWNER: Water and Power Resources Service

LOCATION: State: Colorado Status: Under Construction
County: Lake
River: Mt. Elbert Canal

TYPE OF RESERVOIR SYSTEM	Pure
CAPITAL COST ($/KW)	N.D.
STORAGE (Hours)	U.A.
NUMBER AND TYPE OF UNITS	2-Revs.
GENERATING:	
Effective Head (ft)	475-400
Speed (RPM)	180
Total Capacity (MW)	200
Unit Capacity (MW)	100
Annual Output (MWH)	N.D.
Manufacturer (Turbine/Generator)	A.C./W.
PUMPING:	
Gross Static Head (ft)	485-430
Capacity (MW)	100
Output (cfs)	2,875
Annual Pumping Energy (MWH)	N.D.

PUMP MODE STARTING METHOD: Auxiliary starting motors

DATE OF INITIAL OPERATION (pumped storage only)	1985
NUMBER OF FUTURE UNITS	U.A.
ULTIMATE GENERATING CAPACITY (MW)	U.A.

ADDITIONAL
DESCRIPTION: The Water and Power Resources Service's Mt. Elbert pumped storage project is part of its Fryingpan-Arkansas Project that has been constructed to divert water from the western slope of the Continental Divide to the eastern slope where it is to be used for an expanding population. Mt. Elbert Dam is about 80 miles southwest of Denver and about 12 miles southwest of Leadville, Colorado. Water from Mt. Elbert Forebay discharges through the turbines into Twin Lakes Reservoir. Two 100-MW reversible units will operate with heads ranging from 400 to 475 feet. The units are not yet in commercial operation.

FACILITY NAME: Mud Pond FERC Project Number: 2825

OWNER: International Generation & Transmission Co., Inc.

LOCATION: State: New Hampshire Status: Preliminary report
County: Coos
River: Ammonoosu

TYPE OF RESERVOIR SYSTEM	Pure	
CAPITAL COST ($/KW)	U.A.	
STORAGE (Hours)	U.A.	
NUMBER AND TYPE OF UNITS		Revs.
GENERATING:		
Effective Head (ft)		U.A.
Speed (RPM)		U.A.
Total Capacity (MW)		400
Unit Capacity (MW)		100
Annual Output (MWH)		U.A.
Manufacturer (Turbine/Generator)		U.A.
PUMPING:		
Gross Static Head (ft)		220
Capacity (MW)		400
Output (cfs)		U.A.
Annual Pumping Energy (MWH)		U.A.
Manufacturer		U.A.
PUMP MODE STARTING METHOD		U.A.
DATE OF INITIAL OPERATION (pumped storage only)		U.A.
NUMBER OF FUTURE UNITS		None
ULTIMATE GENERATING CAPACITY (MW)		400

ADDITIONAL DESCRIPTION: The International Generation and Transmission Company, Inc., on November 9, 1977, applied to the FERC for a preliminary permit for its proposed Mud Pond pumped storage project that would be located on the Upper Ammonoosuc River and its North Branch in Coos County, New Hampshire. The FERC issued the applicant a three-year preliminary permit on April 13, 1979. Kilkenny Dam and Reservoir on the Upper Ammonoosuc River, with a surface area of 2,300 acres and a storage capacity of 168,000 acre-feet, would serve as the upper reservoir. West Milan Dam and Reservoir on the North Branch, with a surface area of 800 acres and a storage capacity of 26,670 acre-feet, would serve as the lower reservoir and would also be used as the cooling pond for a planned nuclear generating plant. The four-unit 400-MW pumped storage plant would operate under an average head of 220 feet.

FACILITY NAME: Muddy Run

FERC Project Number: 2355

OWNER: Philadelphia Electric Co.

LOCATION: State: Pennsylvania

County: Lancaster
River: Susquehanna

Status: Operating

TYPE OF RESERVOIR SYSTEM	Pure
CAPITAL COST ($/KW)	102
STORAGE (Hours)	13.5
NUMBER AND TYPE OF UNITS	8-Revs.
GENERATING:	
Effective Head (ft)	401-346
Speed (RPM)	180
Total Capacity (MW)	800
Unit Capacity (MW)	100
Annual Output (MWH)	1,118,361
Manufacturer (Turbine/Generator)	BLH/W.
PUMPING:	
Gross Static Head (ft)	411-361
Capacity (MW)	800
Output (cfs)	19,600
Annual Pumping Energy (MWH)	1,615,129

PUMP MODE STARTING METHOD: Across the line-reduced voltage

DATE OF INITIAL OPERATION (pumped storage only)	1967
NUMBER OF FUTURE UNITS	None
ULTIMATE GENERATING CAPACITY (MW)	800

ADDITIONAL DESCRIPTION: The upper reservoir of the Muddy Run Plant can impound 60,500 acre-feet of water, of which 35,500 acre-feet are in the upper 50 feet and usable for power. The usable storage is equivalent to about four feet in the lower reservoir and is adequate to provide about 14 hours of operation at full load. The gross static head is 411 feet. Operation of the Muddy Run plant causes frequent and rapid changes in the level of the upper reservoir, making it unsatisfactory for recreational use. However, a dam has been constructed across one of the remote fingers of the reservoir, providing a 98-acre, constant-level recreational lake suitable for boating. A recreation park at the lake, equipped with camping and other facilities, receives extensive use.

FACILITY NAME: Northfield Mountain FERC Project Number: 2485

OWNER: Connecticut Light and Power Co.,
Hartford Electric & Light Co.,
Western Massachusetts Electric Co.

LOCATION: State: Massachusetts Status: Operating
County: Franklin
River: Connecticut

TYPE OF RESERVOIR SYSTEM	Pure
CAPITAL COST ($/KW)	144
STORAGE (Hours)	8.5
NUMBER AND TYPE OF UNITS	4-Revs.
GENERATING:	
Effective Head (ft)	815-700
Speed (RPM)	257
Total Capacity (MW)	1000
Unit Capacity (MW)	250
Annual Output (MWH)	321,346
Manufacturer (Turbine/Generator)	BLH/G.E.
PUMPING:	
Gross Static Head (ft)	825-720
Capacity (MW)	1000
Output (cfs)	12,000
Annual Pumping Energy (MWH)	450,367

PUMP MODE STARTING METHOD: Auxiliary starting motors

DATE OF INITIAL OPERATION (pumped storage only)	1972
NUMBER OF FUTURE UNITS	None
ULTIMATE GENERATING CAPACITY (MW)	1,000

ADDITIONAL
DESCRIPTION: See Section 2.3.2.

FACILITY NAME: Oak Creek | FERC Project Number: 2773

OWNER: Oak Creek Power Company

LOCATION: State: Colorado | Status: Preliminary permit application pending

County: Routt
River: Green Creek & Yamp River

TYPE OF RESERVOIR SYSTEM	Pure
CAPITAL COST ($/KW)	U.A.
STORAGE (Hours)	U.A.
NUMBER AND TYPE OF UNITS	9-Revs.
GENERATING:	
Effective Head (ft)	2150
Speed (RPM)	U.A.
Total Capacity (MW)	3600
Unit Capacity (MW)	400
Annual Output (MWH)	U.A.
Manufacturer (Turbine/Generator)	U.A.
PUMPING:	
Gross Static Head (ft)	U.A.
Capacity (MW)	3600
Output (cfs)	U.A.
Annual Pumping Energy (MWH)	U.A.
PUMP MODE STARTING METHOD	U.A.
DATE OF INITIAL OPERATION (pumped storage only)	U.A.
NUMBER OF FUTURE UNITS	None
ULTIMATE GENERATING CAPACITY (MW)	3600

ADDITIONAL
DESCRIPTION: The Oak Creek Power Company, on June 1, 1976, filed an application for a preliminary permit with the FERC for its proposed nine-unit 3,600-MW Oak Creek pumped storage project that would be located in Routt County, Colorado. The upper reservoir would be the Lower Green River Reservoir on Green Creek. The Blacktail Reservoir on the Yamp River would be the lower reservoir. The generating units would be in an underground powerhouse at the lower reservoir and would operate under a maximum gross static head of 2,150 feet. The preliminary permit application is still pending.

FACILITY NAME: O'Neill — FERC Project Number: N.A.

OWNER: Water and Power Resources Service

LOCATION: State: California — Status: Operating
County: Butte
River: San Luis Creek

TYPE OF RESERVOIR SYSTEM	Pure
CAPITAL COST ($/KW)	U.A.
STORAGE (Hours)	U.A.
NUMBER AND TYPE OF UNITS	6-Revs.
GENERATING:	
Effective Head (ft)	U.A.
Speed (RPM)	200
Total Capacity (MW)	25.2
Unit Capacity (MW)	4.2
Annual Output (MWH)	U.A.
Manufacturer (Turbine/Generator)	F.M./G.E.
PUMPING:	
Gross Static Head (ft)	56-44
Capacity (MW)	U.A.
Output (cfs)	700
Annual Pumping Energy (MWH)	U.A.
PUMP MODE STARTING METHOD:	Across the line
DATE OF INITIAL OPERATION (pumped storage only)	1967
NUMBER OF FUTURE UNITS	U.A.
ULTIMATE GENERATING CAPACITY (MW)	U.A.

ADDITIONAL DESCRIPTION: The O'Neill Project of the Water and Resources Service is on San Luis Creek near Los Banos, California. It is a part of the San Luis Unit of the Central Valley Project. The six-unit pumping-generating plant has a total capacity of 25.2 MW and operates with heads ranging from 44 to 56 feet. O'Neill Forebay, formed by the construction of O'Neill Dam, serves both as the upper reservoir of the O'Neill Plant and the lower reservoir of the San Luis pumped storage plant. O'Neill Forebay also serves as a link in the canal system between the North San Joaquin Division of the California Aqueduct and the San Luis Canal.

FACILITY NAME: Prattsville | FERC Project Number: 2729

OWNER: Power Authority of the State of New York

LOCATION: State: New York | Status: License application pending

Counties: Greene, Delaware, Schoharie

River: Schoharie Creek

TYPE OF RESERVOIR SYSTEM	Pure
CAPITAL COST ($/KW)	U.A.
STORAGE (Hours)	U.A.
NUMBER AND TYPE OF UNITS	4-Revs.
GENERATING:	
Effective Head (ft)	U.A.
Speed (RPM)	U.A.
Total Capacity (MW)	1000
Unit Capacity (MW)	250
Annual Output (MWH)	U.A.
Manufacturer (Turbine/Generator)	U.A.
PUMPING:	
Gross Static Head (ft)	U.A.
Capacity (MW)	U.A.
Output (cfs)	U.A.
Annual Pumping Energy (MWH)	U.A.
PUMP MODE STARTING METHOD	U.A.
DATE OF INITIAL OPERATION (pumped storage only)	U.A.
NUMBER OF FUTURE UNITS	None
ULTIMATE GENERATING CAPACITY (MW)	400

ADDITIONAL DESCRIPTION: See Section 2.3.6.

FACILITY NAME: Raccoon Mountain FERC Project Number: N.A.

OWNER: Tennessee Valley Authority

LOCATION: State: Tennessee Status: Operating
County: Marion
River: Tennessee

TYPE OF RESERVOIR SYSTEM	Pure
CAPITAL COST ($/KW)	178
STORAGE (Hours)	20
NUMBER AND TYPE OF UNITS	4-Revs.
GENERATING:	
Effective Head (ft)	1017-870
Speed (RPM)	300
Total Capacity (MW)	1530
Unit Capacity (MW)	382.5
Annual Output (MWH)	27,714
Manufacturer (Turbine/Generator)	A.C./A.C.
PUMPING:	
Gross Static Head (ft)	1040-890
Capacity (MW)	1530
Output (cfs)	12,700
Annual Pumping Energy (MWH)	51,142

PUMP MODE STARTING METHOD: Converter-inverter

DATE OF INITIAL OPERATION (pumped storage only)	1979
NUMBER OF FUTURE UNITS	None
ULTIMATE GENERATING CAPACITY (MW)	1530

ADDITIONAL DESCRIPTION: Tennessee Valley Authority's four-unit 1530-MW Raccoon Mountain Project contains the largest reversible units in operation in the United States. The 528-acre upper reservoir is on the top of a mountain. It was created by constructing a rockfill dam along two sides of the curving mountain top with confinement on the other two sides provided by natural ridges. It has a usable storage capacity of 35,900 acre-feet. The lower reservoir is provided by the Nickajack Reservoir on the Tennessee River, about 6.5 miles west of Chattanooga, Tennessee. A circular concrete-lined intake tunnel 35 feet in diameter connects the upper reservoir and the underground powerplant. The tunnel drops vertically 900 feet from the floor of the upper reservoir, continues on a three percent grade down to a point 400 feet upstream from the powerplant chamber where it divides into two concrete-lined tunnels 24.5 feet in diameter, and then divides into four tunnels 17.5 feet in diameter. The powerhouse chamber is 72 feet wide by 165 feet high by 490 feet long.

FACILITY NAME: Rocky Mountain

FERC Project Number: 2725

OWNER: Georgia Power Co.

LOCATION: State: Georgia
County: Floyd
River: Heath Creek

Status: Under Construction

TYPE OF RESERVOIR SYSTEM	Pure
CAPITAL COST ($/KW)	U.A.
STORAGE (Hours)	8
NUMBER AND TYPE OF UNITS	3-Revs.
GENERATING:	
Effective Head (ft)	U.A
Speed (RPM)	225
Total Capacity (MW)	675
Unit Capacity (MW)	225
Annual Output (MWH)	N.D.
Manufacturer (Turbine/Generator)	U.A.
PUMPING:	
Gross Static Head (ft)	652
Capacity (MW)	U.A.
Output (cfs)	12,200
Annual Pumping Energy (MWH)	N.D.
PUMP MODE STARTING METHOD	U.A.
DATE OF INITIAL OPERATION (pumped storage only)	1986
NUMBER OF FUTURE UNITS	None
ULTIMATE GENERATING CAPACITY (MW)	675

ADDITIONAL
DESCRIPTION: The three-unit 675-MW Rocky Mountain Project is being constructed by Georgia Power Company in Floyd County approximately 10 miles northwest of Rome, Georgia. The lower reservoir will be on Heath Creek, a headwater tributary of the Coosa River. The upper reservoir is being constructed in a natural depression atop Rocky Mountain by a continuous earth and rockfill dike approximately 13,500 feet long, with an average height of 50 feet. The reservoir will have a surface area of 221 acres and a usable storage capacity of about 9,300 acre-feet in a drawdown of 45.5 feet. The project is scheduled for initial operation in 1983. Following issuance of the license; the company requested permission to locate the lower dam approximately one mile downstream to take advantage of better geologic conditions. This change would not alter the elevation of the lower reservoir nor the location of the powerplant.

FACILITY NAME: Rocky River | FERC Project Number: 2632

OWNER: Connecticut Light and Power Co.

LOCATION: State: Connecticut | Status: Operating

County: Litchfield
River: Lake Candlewood & Housatonic River

TYPE OF RESERVOIR SYSTEM Combined

CAPITAL COST ($/KW) 216

STORAGE (Hours) 830

NUMBER AND TYPE OF UNITS	2-Revs.	1-Conv.
GENERATING:		
Effective Head (ft)	219-190	219-190
Speed (RPM)	327	200
Total Capacity (MW)	7	24
Unit Capacity (MW)	3.5	21
Annual Output (MWH)	19,964	N.A.
Manufacturer (Turbine/Generator)	Worthington/G.E.	S.M. Smith/G.E.
PUMPING:		
Gross Static Head (ft)	230-200	
Capacity (MW)	327	
Output (cfs)	U.A.	
Annual Pumping Energy (MWH)	5,311	

PUMP MODE STARTING METHOD Manually at reduced voltage

DATE OF INITIAL OPERATION (pumped storage only) 1929*

NUMBER OF FUTURE UNITS None

ULTIMATE GENERATING CAPACITY (MW) 31

---

*2 pumping units were rewired in 1952 so that they can also be used as generating units.

FACILITY NAME: Salina	FERC Project Number: 2524
OWNER: Grand River Dam Authority	
LOCATION: State: Oklahoma County: Moyes River: Grand	Status: Operating

---

TYPE OF RESERVOIR SYSTEM	Pure
CAPITAL COST ($/KW)	115
STORAGE (Hours)	19
NUMBER AND TYPE OF UNITS	6-Revs.
GENERATING:	
Effective Head (ft)	243-223
Speed (RPM)	171.5
Total Capacity (MW)	260
Unit Capacity (MW)	43.2
Annual Output (MWH)	232,650
Manufacturer (Turbine/Generator)	A.C./W.
PUMPING:	
Gross Static Head (ft)	246-228
Capacity (MW)	286
Output (cfs)	10,000
Annual Pumping Energy (MWH)	386,703

PUMP MODE STARTING METHOD: Across the line

DATE OF INITIAL OPERATION (pumped storage only)	1968
NUMBER OF FUTURE UNITS	6
ULTIMATE GENERATING CAPACITY (MW)	520

ADDITIONAL DESCRIPTION: Grand River Dam Authority's Salina Project is located on Chimney Rock Hollow and Little Salina Creek, tributaries of the Grand River in Oklahoma. The ultimate development was planned for 12 generating units, to be built in four stages of 130 MW each. It was to have two interconnected upper reservoirs, Chimney Rock and Upper Salina, with the latter to be built as a part of the third stage. The reservoir of the conventional Markham Ferry Project serves as the lower reservoir of the pumped storage development. Stages one and two were constructed and placed in operation in 1968. Construction has not begun on stages three and four.

FACILITY NAME: San Luis | FERC Project Number: N.A.

OWNER: Water & Power Resources Service

LOCATION: State: California | Status: Operating
County: Merced
River: San Luis Creek

TYPE OF RESERVOIR SYSTEM	Pure
CAPITAL COST ($/KW)	U.A.
STORAGE (Hours)	N.A.
NUMBER AND TYPE OF UNITS	8-Revs.
GENERATING:	
Effective Head (ft)	316-114*
Speed (RPM)	120/150**
Total Capacity (MW)	424
Unit Capacity (MW)	53
Annual Output (MWH)	U.A.
Manufacturer (Turbine/Generator)	Hitachi/G.E.
PUMPING:	
Gross Static Head (ft)	327-101
Capacity (MW)	424
Output (cfs)	14,900
Annual Pumping Energy (MWH)	U.A.

PUMP MODE STARTING METHOD: Across the line-reduced voltage

DATE OF INITIAL OPERATION (pumped storage only)	1968
NUMBER OF FUTURE UNITS	None
ULTIMATE GENERATING CAPACITY (MW)	424

---

*Generating capability ceases when the net head is below 177 and 114 feet for the 150 and 120 apm units, respectively.

**Two generators on same shaft.

ADDITIONAL DESCRIPTION: The San Luis Dam is an earthfill dam 3½ miles long and is on San Luis Creek near Los Banos California. It creates an offstream reservoir with a storage capacity of more than 2,000,000 acre-feet. The principal purpose of the reservoir is to store water for irrigation and urban and industrial uses. Water from the Sacramento-San Joaquin Delta, some 100 miles to the north, is transported to the San Luis project by the California Aqueduct and the Delta-Mendota Canal. Water from the canal is diverted into a channel from which the O'Neill pumping plant pumps the water through a head of about 50 feet into the O'Neill Forebay. O'Neill Forebay has an active storage capacity of 20,800 acre-feet and serves as the lower reservoir of the San Luis pumped storage plant.

FACILITY NAME: Seboyeta FERC Project Number: EL 79-18

OWNER: Public Service Co. of New Mexico

LOCATION: State: New Mexico Status: Awaiting construction
County: Valencia
River: Water pumped from mine

TYPE OF RESERVOIR SYSTEM	Pure
CAPITAL COST ($/KW)	U.A.
STORAGE (Hours)	U.A.
NUMBER AND TYPE OF UNITS	4-Revs.
GENERATING:	
Effective Head (ft)	U.A.
Speed (RPM)	U.A.
Total Capacity (MW)	600
Unit Capacity (MW)	150
Annual Output (MWH)	U.A.
Manufacturer (Turbine/Generator)	U.A.
PUMPING:	
Gross Static Head (ft)	U.A.
Capacity (MW)	U.A.
Output (cfs)	U.A.
Annual Pumping Energy (MWH)	U.A.
PUMP MODE STARTING METHOD	U.A.
DATE OF INITIAL OPERATION (pumped storage only)	1991*
NUMBER OF FUTURE UNITS	U.A.
ULTIMATE GENERATING CAPACITY (MW)	U.A.

*Estimated

ADDITIONAL DESCRIPTION: On May 15, 1979, the Public Service Company of New Mexico filed a petition for a declaratory order requesting that the Federal Energy Regulatory Commission determine that a license under Part I of the Federal Power Act is not required for its proposed Seboyeta pumped storage project. The project would be located in Valencia County, New Mexico, about 45 miles west of Albuquerque. It would contain upper and lower reservoirs formed by rockfill dams and a powerhouse with four 150-MW reversible units. The project's lower reservoir would be located on what has been characterized variously as an arroyo, a dry wash, or an unnamed intermittent stream. The water supply for the lower reservoir would be obtained chiefly by pumping groundwater from the Bokum Resources Marquez Mine through a 10-mile-long conduit. On March 21, 1980, the Commission, in Docket No. EL 79-18, issued a declaratory order finding that the project, as proposed, is not required to be licensed under Part I of the Federal Power Act. Although the company is now permitted to proceed with the project, actual construction may not begin for several years, consistent with the company's long-range projection of capacity needs.

FACILITY NAME: Senator Wash FERC Project Number: N.A.

OWNER: Water and Power Resources Service

LOCATION: State: California Status: Operating
County: Yuma
River: Colorado

TYPE OF RESERVOIR SYSTEM	Pure
CAPITAL COST ($/KW)	U.A.
STORAGE (Hours)	U.A.
NUMBER AND TYPE OF UNITS	6-Revs.
GENERATING:	
Effective Head (ft)	U.A.
Speed (RPM)	U.A.
Total Capacity (MW)	7
Unit Capacity (MW)	1.2
Annual Output (MWH)	U.A.
Manufacturer (Turbine/Generator)	U.A.
PUMPING:	
Gross Static Head (ft)	74
Capacity (MW)	U.A.
Output (cfs)	160
Annual Pumping Energy (MWH)	U.A.
PUMP MODE STARTING METHOD	U.A.
DATE OF INITIAL OPERATION (pumped storage only)	1966
NUMBER OF FUTURE UNITS	U.A.
ULTIMATE GENERATING CAPACITY (MW)	U.A.

FACILITY NAME: Smith Mountain FERC Project Number: 2210

OWNER: Appalachian Power Co.

LOCATION: State: Virginia
County: Franklin
River: Roanoke

Status: Operating

TYPE OF RESERVOIR SYSTEM	Combined	
CAPITAL COST ($/KW)	119	
STORAGE (Hours)	5	
NUMBER AND TYPE OF UNITS	3-Revs.	2-Conv.
GENERATING:		
Effective Head (ft)	U.A.	U.A.
Speed (RPM)	105.9	100
Total Capacity (MW)	236	300
Unit Capacity (MW)	104/66*	150
Annual Output (MWH)	634,696	N.A.
Manufacturer (Turbine/Generator)	A.C./A.C.	BLH/G.E.
PUMPING:		
Gross Static Head (ft)	195-174	
Capacity (MW)	150	
Output (cfs)	8,200	
Annual Pumping Energy (MWH)	677,936	

PUMP MODE STARTING METHOD: Across the line-reduced voltage

DATE OF INITIAL OPERATION (pumped storage only)	1965
NUMBER OF FUTURE UNITS	None
ULTIMATE GENERATING CAPACITY (MW)	536

---

*2 units at 66 and one unit at 104.

ADDITIONAL
DESCRIPTION: Appalachian Power Company's Smith Mountain Project is a combined development on the Roanoke River in Virginia. The installation consists of three reversible units, two of 66 MW each and one of 104 MW, and two conventional units of 150 MW each. The upper reservoir, with a capacity of about 1.1 million acre-feet, was created by the construction of an arch dam, about 235 feet high and approximately 815 feet long at the crest. The lower reservoir, with a capacity of about 112,500 acre-feet, was impounded by the Leesville concrete gravity dam 17 miles downstream from the Smith Mountain Dam. Leesville Dam is about 94 feet high and 980 feet long at the crest. A powerplant at the Leesville Dam contains two conventional units, each rated 20 MW. At one time the Smith Mountain site was considered for development with only a 35-MW installation.

FACILITY NAME: Taum Sauk　　　　FERC Project Number: 2277

OWNER: Union Electric Co.

LOCATION: State: Missouri　　　　Status: Operating
County: Reynolds
River: Black

TYPE OF RESERVOIR SYSTEM	Pure
CAPITAL COST ($/KW)	112
STORAGE (Hours)	7.7
NUMBER AND TYPE OF UNITS	2-Revs
GENERATING:	
Effective Head (ft)	829-714
Speed (RPM)	200
Total Capacity (MW)	408
Unit Capacity (MW)	204
Annual Output (MWH)	20,890
Manufacturer (Turbine/Generator)	A.C./G.E.
PUMPING:	
Gross Static Head (ft)	863-755
Capacity (MW)	358
Output (cfs)	4,400
Annual Pumping Energy (MWH)	52,962.9

PUMP MODE STARTING METHOD: Auxiliary starting motors

DATE OF INITIAL OPERATION (pumped storage only)	1963
NUMBER OF FUTURE UNITS	None
ULTIMATE GENERATING CAPACITY (MW)	408

ADDITIONAL
DESCRIPTION: See Section 2.3.1.

FACILITY NAME: Thermalito | FERC Project Number: 2100

OWNER: California Department of Water Resources

LOCATION: State: California
County: Butte
River: Feather

Status: Operating

TYPE OF RESERVOIR SYSTEM	Combined	
CAPITAL COST ($/KW)	U.A.	
STORAGE (Hours)	N.A.	
NUMBER AND TYPE OF UNITS	3-Revs.	1-Conv.
GENERATING:		
Effective Head (ft)	101-85	103-81
Speed (RPM)	112.5	138.5
Total Capacity (MW)	82.5	32.5
Unit Capacity (MW)	27.5	32.5
Annual Output (MWH)	U.A.	N.A.
Manufacturer (Turbine/Generator)	A.C./W.	A.C./W.
PUMPING:		
Gross Static Head (ft)	102-86	
Capacity (MW)	90	
Output (cfs)	9,000	
Annual Pumping Energy (MWH)	U.A.	
PUMP MODE STARTING METHOD:	Across the line	
DATE OF INITIAL OPERATION (pumped storage only)	1968	
NUMBER OF FUTURE UNITS	None	
ULTIMATE GENERATING CAPACITY (MW)	82.5	

ADDITIONAL
DESCRIPTION: The Edward G. Hyatt and Thermalito Powerplants are parts of the California Water Project constructed and operated by the California Department of Water Resources. The primary purpose of the project is to convey surplus water from northern California to areas of need in central and southern California. The key construction feature is 770-foot-high Oroville Dam on the Feather River which creates a reservoir with a storage capacity of 3,484,000 acre-feet. Downstream from the Oroville Dam is the Thermalito Diversion Dam that serves the dual function of creating the lower reservoir for the Edward G. Hyatt reversible units and diverting the Feather River into the Thermalito Canal. Water from the canal discharges into Thermalito Forebay which is the upper reservoir for the Thermalito pumping-generating plant. The Thermalito Plant houses three 27.5-MW reversible units and one 32.5-MW conventional unit. This power complex is unique because it includes two stages of both pumping and generation. Water discharged from Oroville Reservoir is used for power generation in both the Edward G. Hyatt and Thermalito powerplants and is returned from the Thermalito Afterbay to Oroville Reservoir by pumping, using the reversible turbines in the two plants.

FACILITY NAME: Village Bend FERC Project Number: 2733

OWNER: Brazos Electric

LOCATION: State: Texas
County: U.A.
River: Brazos

Status: Submitted license applicatio

TYPE OF RESERVOIR SYSTEM	Pure
CAPITAL COST ($/KW)	U.A.
STORAGE (Hours)	U.A.
NUMBER AND TYPE OF UNITS	4-Revs.
GENERATING:	
Effective Head (ft)	U.A.
Speed (RPM)	U.A.
Total Capacity (MW)	730
Unit Capacity (MW)	U.A.
Annual Output (MWH)	U.A.
Manufacturer (Turbine/Generator)	U.A.
PUMPING:	
Gross Static Head (ft)	400
Capacity (MW)	730
Output (cfs)	U.A.
Annual Pumping Energy (MWH)	U.A.
PUMP MODE STARTING METHOD	U.A.
DATE OF INITIAL OPERATION (pumped storage only)	N.D.
NUMBER OF FUTURE UNITS	U.A.
ULTIMATE GENERATING CAPACITY (MW)	U.A.

ADDITIONAL
DESCRIPTION: The Village Bend pumped storage project would be built on the Brazos River about 57 miles downstream from the Brazos River Authority's Morris Sheppard Dam. It would consist of an upper reservoir impounded by a 300-foot-high dam on a tributary stream, a powerhouse having a capacity of 730 MW, and a 41-mile-long lower reservoir impounded by a concrete dam on the Brazos River. An application for preliminary permit was filed July 2, 1973, and the Federal Power Commission issued a permit on February 10, 1975. The permit expired in 1978 without the filing of an application for license. The Brazos Cooperative does, however, plan to proceed with the project, because on August 5, 1980, it submitted to the Federal Energy Regulatory Commission for preliminary review, copies of a draft application for license.

FACILITY NAME: Wallace — FERC Project Number: 2413

OWNER: Georgia Power Co.

LOCATION: State: Georgia
County: Hancock & Putnam
River: Oconee

Status: Operating

TYPE OF RESERVOIR SYSTEM	Combined	
CAPITAL COST ($/KW)	2,714	
STORAGE (Hours)	42.9	
NUMBER AND TYPE OF UNITS	4-Revs.	2-Conv.
GENERATING:		
Effective Head (ft)	U.A.	U.A.
Speed (RPM)	86	86
Total Capacity (MW)	216	108
Unit Capacity (MW)	54	54
Annual Output (MWH)	N.D.	N.D.
Manufacturer (Turbine/Generator)	A.C./G.E.	
PUMPING:		
Gross Static Head (ft)	97-94	
Capacity (MW)	248	
Output (cfs)	24,000	
Annual Pumping Energy (MWH)	N.D.	

PUMP MODE STARTING METHOD: Across the line

DATE OF INITIAL OPERATION (pumped storage only)	1980
NUMBER OF FUTURE UNITS	None
ULTIMATE GENERATING CAPACITY (MW)	324

ADDITIONAL
DESCRIPTION: Georgia Power Company's 324-MW Wallace Project is a combined development that contains six 54-MW units, two are conventional and four reversible. It is located at about river mile 173 on the Oconee River in Georgia. The Wallace Reservoir has a surface area of about 21,000 acres and a gross storage capacity of 470,000 acre-feet. Lake Sinclair of the company's conventional Furman Schools hydroelectric development serves as the lower reservoir. The gross static head at the project is about 95 feet.

FACILITY NAME: Yards Creek FERC Project Number: 2309

OWNER: Public Service Electric & Gas Co.
Jersey Central Power & Light Co.

LOCATION: State: New Jersey
County: Warren
River: Yards Creek

Status: Operating

TYPE OF RESERVOIR SYSTEM	Pure
CAPITAL COST ($/KW)	82
STORAGE (Hours)	8.77
NUMBER AND TYPE OF UNITS	3-Revs.
GENERATING:	
Effective Head (ft)	735-651
Speed (RPM)	240
Total Capacity (MW)	387
Unit Capacity (MW)	137/112.9*
Annual Output (MWH)	261,833
Manufacturer (Turbine/Generator)	BLH/G.E.
PUMPING:	
Gross Static Head (ft)	760-688
Capacity (MW)	338
Output (cfs)	5,440
Annual Pumping Energy (MWH)	403,513

PUMP MODE STARTING METHOD: Across the line-reduced voltage

DATE OF INITIAL OPERATION (pumped storage only)	1965
NUMBER OF FUTURE UNITS	None
ULTIMATE GENERATING CAPACITY (MW)	387

*Two units at 137 and one unit at 112.9.

ADDITIONAL
DESCRIPTION: In 1965 the Yards Creek pumped storage project in New Jersey, jointly owned by Jersey Central Power & Light Company and Public Service Electric and Gas Company, went on-line with three units of 112.5 MW each. The upper reservoir is located in a natural depression on the easterly slope of Kittatinny Mountain, adjacent to the Delaware River near the Delaware Water Gap. The lower reservoir is on Yards Creek and is connected to a small auxiliary reservoir which is used to provide make-up water and seasonal storage for low flow augmentation in Yards Creek. Gross static head is 760 feet. The upper reservoir can store 4,650 acre-feet of water, which is enough to operate the plant at full load for about nine hours.

A.2 OTHER PUMPED STORAGE PROJECTS

Table A-3 lists projects having a prelicense status and one project being considered for Federal authorization (statistical data and further descriptive material by plant can be found in the preceding inventory). Six of the seven are involved in various stages of licensing. Part I of the Federal Power Act authorizes the Federal Energy Regulatory Commission (FERC) to issue preliminary permits for a period of 3 years. A preliminary permit is for the sole purpose of maintaining priority of application for license. It does not authorize the construction of any project facilities. The priority ceases when the preliminary permit expires unless an application for license has been filed. A license authorizes construction and operation, under conditions specified in the license, and may be issued for a term of not more than 50 years.

Over the last 20 years a large number of potential pumped storage projects have been studied by a wide range of public and private entities and Federal agencies. Of these the projects that have had licensing status with FERC but were never constructed are listed in Table A-4 and described below. It is informative to note the wide variety of circumstances that led to the discontinuation of the projects.

On June 25, 1964, the Monongahela Power Company applied for a preliminary permit from the Federal Power Commission to study the proposed Rowlesburg pumped storage development. The FPC issued a preliminary permit on August 17, 1965. The project was to be located at the authorized Federal Rowlesburg Reservoir on the Cheat River in Preston County, West Virginia. The Federal authorizing legislation provided that the power features at Rowlesburg were not to be undertaken by the Corps of Engineers until such time as the FPC had completed its actions on any pumped storage applications for private development. The proposed Federal Rowlesburg Reservoir would serve as the lower reservoir. The upper reservoir, with a capacity of 6,000 acre-feet, was to be constructed on high land west of the Rowlesburg Reservoir. Preliminary studies by the company pointed to an underground powerhouse with a two- or three-unit installation having a total capacity up to 525 MW. The pumping head would be approximately 750 feet and, by discharging into the river below Rowlesburg Dam, the head for generating would be about 900 feet. The company decided not to apply for a license, advising the FPC on July 23, 1968, that the "water flows required for the proposed project

TABLE A-3

Pumped Storage Projects Having Federal
or Licensing Status as of November 1, 1980
(not licensed or in operation)

Project or Plant name	State	Owner or Developer	Year of Initial Study	Reversible Capacity-MW
Village Bend	Texas	Brazos Electric	1973	730
Azure	Colorado	Colo. R. Water Cons. Dist.	1976	240
Oak Creek	Colorado	Oak Creek Power Co.	1976	3,600
Prattsville	New York	Power Auth. of the State of N.Y.	1976	1,000
Brumley Gap	Virginia	Appalachian Power Co.	1977	3,000
Gregory County	South Dakota	Corps of Engineers	1977	1,180
Mud Pond	New Hampshire	International Gen. and Trans. Co.	1977	400
		Total		10,150

TABLE A-4

Other Pumped Storage Projects that have had Federal or Licensing Status

Project or Plant name	State	Owner or Developer	Period Studied	Reversible Capacity-MW
Rowlesburg	West Virginia	Monongahela Power Co.	1964-68	525
Dirty Face Mtn.	Washington	P.U.D. No. 1 of Chelan County	1965-71	45
Longwood Valley	New Jersey	Jersey Central P. & L Co.	1966-70	122
Blair Mountain	Colorado	Colo. River Water Cons. Dist	1967-75	525
Blue Ridge	Virginia	Appalachian Power Co.	1967-76	1,600
Merrill Lake	Washington	P.U.D. No. 1 of Cowlitz County	1967-71	500
Havasu	Arizona	Arizona Power Authority	1969-74	1,000
Canaan Mtn.	Conn.	Conn. Lt. & Pwr. Co.[1]	1970-74	1,500
Shenob Brook	Mass.-Conn.	Conn. Lt. & Pwr. Co.[1]	1970-71	1,500
Green River	North Carolina	EPIC, Inc.	1970-74	2,000
Marble Valley	Virginia	Virginia Electric and Pwr. Co.	1970-71	1,500
Antilon Lake	Washington	P.U.D. No.1 of Chelan County	1971-75	2,000
Poor Mtn.	Virginia	Virginia Electric and Power Co.	1971-75	1,500

[1] Joint project of Connecticut Light and Power Company, Western Massachusetts Electric Company, and Hartford Electric Light Company.

TABLE A-4 (cont'd)

Other Pumped Storage Projects that have had Federal or Licensing Status

Project or Plant name	State	Owner or developer	Period Studied	Reversible Capacity-MW
Stony Creek	Pennsylvania	Pennsylvania Power and Lt. Co.[2]	1971-75	1,500
Brown's Canyon	Washington	P.U.D. No. 1 of Douglas County	1972-76	2,000
Black Star	California	Southern California Edison Co.	1973-76	1,235
Breakabeen	New York	Power Authority of the State of N.Y.	1973-76	1,000
Jackson County	North Carolina	Carolina Pwr. and Lt. Co.	1973-75	1,000
Madison County	North Carolina	Carolina Pwr. and Lt. Co.	1973-76	2,000
Randolph	Virginia	Southside Electric Cooperative	1974-78	4,090
Boyd County	Nebraska	Nebraska Public Power Dist.	1974-80	1,336
Mt. Hope	New Jersey	Jersey Central Pwr. and Lt. Co.	1975-77	1,000
Powell Mtn.	Virginia	Appalachian Power Co.	1977-79	3,000
			Total	32,478

[2]Joint project of Pennsylvania Power and Light Company and Metropolitan Edison Company.

could not be made compatible with governmental requirements for recreation development in the area."

The Public Utility District of Chelan County, Washington, applied on May 10, 1965, for a license to construct the Chiwawa hydroelectric development in Chelan County, Washington. It was to include the Dirty Face Mountain powerhouse with one 180-MW conventional unit and pumped storage units of 20 and 45 MW. A dam on the Chiwawa River was to create a reservoir with a storage capacity of 400,000 acre-feet. A 30,000-foot tunnel from the reservoir to the powerhouse would permit the development of a gross head of 672 feet. The application was held in abeyance for a number of years, but a license was never issued.

The Jersey Central Power and Light Company, on December 30, 1966, applied for a license for the proposed three-unit 121.5-MW Longwood Valley pumped storage project that would be adjacent to the Rockaway River in Morris County, New Jersey. The upper and lower reservoirs were to be built by Jersey City as additions to the city's water supply system. The company, in 1970, concluded that it was not economically feasible to proceed with the project, and the FPC on January 7, 1974, dismissed the application for license.

On May 29, 1967, the Colorado River Water Conservation District applied for a preliminary permit for two conventional hydroelectric projects and the Blair Mountain pumped storage development to be located on the South Fork of the White River in Garfield and Rio Blanco counties. It was proposed to enlarge the natural Crater Lake to create a forebay with about 2,000 acre-feet. The lower reservoir was to be created by a dam on the South Fork of the White River where a powerplant would be constructed to utilize a gross head of 2,200 feet. The plant was planned to have an initial capacity of 175 MW and an ultimate capacity of 525 MW. A preliminary permit issued on December 11, 1972, was allowed to expire, probably because the project would be in the Flat Top Wilderness Area.

When the Appalachian Power Company applied for a license in 1967 to construct its proposed Blue Ridge Project on the New River in Virginia, the development was to have six 150-MW reversible units at a main dam and two 40-MW conventional units at a downstream reregulating dam. During a hearing proceeding on the application the company amended its application to provide an eight-unit 1,600-MW pumped storage development and a two-unit 200-MW conventional plant at the reregulating dam. The FPC, on June 14, 1974, issued a license effective January 2, 1975, to the company authorizing construction of the project. The period from June 14 to January 2 was provided to cover the possibility that the Congress might enact legislation during that period "that would delay or foreclose the Blue Ridge Project." The Congress did not enact such legislation during that period but, about one year later, enacted legislation that made a headwater stream of the New River in North Carolina a component of the national wild and scenic rivers system. That action precluded the development of the Blue Ridge Project and the license became void.

Public Utility District No. 1 of Cowlitz County, Washington, on August 17, 1967, applied for a preliminary permit for the Merrill Lake pumped storage project in Washington. As proposed, the upper reservoir would be created by constructing a dam at the outlet of Merrill Lake, a natural lake, to raise the lake's elevation about 60 feet. The existing Yale Lake created by Yale Dam on the Cowlitz River would serve as the lower reservoir. An underground powerhouse with a total capacity of 500 MW was proposed. A preliminary permit issued by the FPC on June 18, 1968, expired without an application for license having been filed.

On August 14, 1969, the Arizona Power Authority applied for a preliminary permit for the four-unit 1,000-MW pumped storage project that would be on the Bill Williams Arm of Lake Havasu in Arizona. Lake Havasu was created by the Federal Parker Dam. The FPC issued a preliminary permit on November 18, 1970, but modified it on December 6, 1972, for a term of 36 months to be effective January 1, 1973. On January 10, 1974, the Authority applied to surrender its permit because of the indefinite status of the development plans of the U.S. Bureau of Reclamation's Central Arizona Project as they affect the possible construction, economics, and financing of the proposed pumped storage project. By order issued May 22, 1974, the FPC accepted surrender of the permit without prejudice.

On February 25, 1970, the Connecticut Light and Power Company, Western Massachusetts Electric Company, and Hartford Electric Company jointly filed two applications for preliminary permits. One was for the Canaan Mountain pumped storage project that would be located on Wangum Lake Brook in Litchfield County, Connecticut. It would consist of an upper reservoir with storage capacity of about 41,000 acre-feet on Canaan Mountain, an underground powerhouse with capacity of 1,000 to 2,000 MW, and a lower reservoir on Wangum Lake Brook. A head of about 900 feet would be developed. The second project, Shenob Brook, was to be on

Shenob Brook about 27 miles southwest of Pittsfield, Massachusetts, in Berkshire County, Massachusetts, and Litchfield County, Connecticut. The upper reservoir would occupy the area at which Plantain Pond is now located, with the lower reservoir being about one mile to the east. This project would also have a capacity in the range of 1,000 to 2,000 MW. The company's plans were to study both projects to determine which would best satisfy the standards for comprehensive development, including comprehensive environmental considerations involving close cooperation with public agencies at the local, state, and Federal levels and with various citizen groups. On June 18, 1971, the applicants applied to withdraw their application for Shenob Brook, stating that a pumped storage project at that site was not feasible at that time. On July 26, 1971, the FPC issued an order granting permission to withdraw that application. On the same date it issued a preliminary permit for the Canaan Valley project. The companies also encountered considerable opposition to construction of that project, and the preliminary permit expired on July 1, 1974, without the filing of an application for license.

EPIC, Inc., a nonprofit corporation which provides power to some municipalities and cooperatives, applied for a preliminary permit on November 19, 1970, for the Green River pumped storage project that would be located on the Green River in Polk County, North Carolina. The project was planned for development in stages, with the initial stage to include two 250-MW units, with eight units in the ultimate development. The upper and lower reservoirs were each to have a storage capacity of 25,000 acre-feet. On January 31, 1972, a preliminary permit was issued to study a two-unit development. On December 27, 1974, EPIC, Inc., sought to withdraw and abandon its preliminary permit and to apply for a new one for the same project because it had not been able to complete studies required by the permit. By order issued June 18, 1975, the FPC denied the request and found that the permit had expired on January 1, 1975.

In 1971, Virginia Electric and Power Company (VEPCO) applied to the FPC for a license to construct the 1,500-MW Marble Valley pumped storage project on a tributary of the James River, a few miles west of Staunton, Virginia. In 1971, VEPCO petitioned to withdraw its application, stating that geological explorations had established that active sink holes and permeable sand zones were present in the planned upper reservoir floor, and zones of badly weathered rock along tunnel lines were far more extensive than originally believed.

On August 23, 1971, the Public Utility District No. 1 of Chelan County, Washington, applied for a preliminary permit to study the Antilon Lake pumped storage project. The applicant's existing Lake Chelan would provide the lower reservoir, while two earth and rock dams would raise the level of the existing Antilon Lake about 120 feet to form an upper reservoir with a surface area of some 320 acres. A four-unit 1,000-MW installation was planned to operate with a normal head of approximately 1,350 feet. A preliminary permit, issued on December 12, 1972, expired without an application for license having been filed.

On April 21, 1971, VEPCO applied for a preliminary permit for the Poor Mountain pumped storage project that would be located on Goose Creek and Bottom Creek, tributaries of the South Fork of the Roanoke River in Virginia. An underground powerhouse would house reversible units having a total capacity of 1,500 MW. They would operate under a maximum head of about 890 feet. On the same date, VEPCO had also applied for a preliminary permit for the Bath County project which is now under construction. A preliminary permit for Poor Mountain was issued on February 1, 1972. It expired on January 31, 1975, without an application for license having been filed.

Pennsylvania Power and Light Company and Metropolitan Edison Company jointly applied for a preliminary permit on September 2, 1971, for the Stony Creek pumped storage development in Dauphin County, Pennsylvania, a few miles northeast of Harrisburg. The lower reservoir was to be on Stony Creek, a tributary of the Susquehanna River, and the upper reservoir was to be at the summit of Third Mountain. The project would operate with a head of about 1,000 feet and have a capacity of approximately 1,500 MW. A preliminary permit, issued December 6, 1972, was allowed to expire on December 1, 1975, without an application for license being filed. The proposed project encountered strong opposition on environmental grounds while it was being studied under the preliminary permit.

On June 29, 1972, the Public Utility District of Douglas County, Washington, applied for a preliminary permit for a four-unit 1,000-MW pumped storage development to be known as Brown's Canyon. Lake Entiat, created by Rocky Reach Dam on the Columbia River, would serve as the lower reservoir. The upper reservoir would be created by diking on a plateau 2,388 feet above the Columbia River. Following receipt of a preliminary permit issued by the FPC on December 27, 1973, the permittee studied a project that would include an underground powerhouse that would house six units having a total capacity of 2,000 MW. The preliminary permit expired December 1, 1976, without an application for license having been filed.

On April 27, 1973, the Southern California Edison Company applied for a preliminary permit to study the four-unit 1,235-MW Black Star pumped storage project. The project would be in Orange County, California, with the upper reservoir being formed by an earthfill dam 246 feet high in Black Star Canyon. The lower reservoir would be created by a similar dam in Fremont Canyon. The capacity of each reservoir would be about 20,000 acre-feet, and the gross static head would be 996 feet. A preliminary permit was issued on June 15, 1976. The FPC, however, by order issued September 9, 1976, vacated its June 15, 1976 order at the request of the permittee. That request was made because of a dramatic change in the estimated cost of construction and operation of the project, with the result that the project was no longer being included in the Company's future generation resource program.

Carolina Power and Light Company, on June 19, 1973, filed an application for preliminary permit for the four-unit 1,000-MW Jackson County pumped storage development. The project would be in Jackson County, North Carolina, on Caney Fork, a tributary of the Tuckasegee River, and on Frady Creek, a branch of Chastine Creek which is a tributary of Caney Fork. The upper reservoir would be formed by a rockfill dam 420 feet high on Frady Creek, and the lower reservoir would be formed by a rockfill dam 255 feet high on Caney Fork. The generating units would operate under heads ranging from 1,275 feet to 1,398 feet. On May 15, 1975, the company applied for surrender of the preliminary permit that had been issued on June 18, 1974, stating that its planned Madison County project was better adapted to development as a pumped storage facility. The company stated, also, that changes in its generation plan and deferral of several base-load generating units made it unnecessary to pursue more than one pumped storage site. By order issued December 1,1975, the FPC accepted surrender of the preliminary permit.

On August 16, 1973, Carolina Power and Light Company applied for a preliminary permit to study the Madison County pumped storage project that would be located on tributaries of the French Broad River in Madison County, North Carolina. The project was proposed to operate with an average head of about 1,175 feet and to have an initial capacity of at least 1,000 MW with an ultimate capacity of 2,000 MW. A preliminary permit was issued on December 12, 1974, but, on September 3, 1976, the company applied to surrender the permit, stating that it is no longer feasible to add this pumped storage generation facility to its system in the foreseeable future. The FPC, by order issued February 22, 1977, accepted surrender of the preliminary permit.

The Southside Electric Cooperative of Crewe, Virginia, on December 12, 1974, applied for a preliminary permit to study a complex of hydroelectric developments on the Roanoke River and tributaries upstream from the Corps of Engineers' John H. Kerr Dam and Reservoir. This so-called Randolph Project would include five developments, namely, Randolph-Hunting (1,260 MW), Turnip-Falling (830 MW), Roanoke-Wallace (780 MW), Cub Creek (800 MW), and Mollys-Seneca Creek (420 MW), a total of 4,090 MW. All units would be reversible although natural streamflow would provide a significant amount of the projected generation. The FPC issued a preliminary permit on April 8, 1976, but the FERC, on December 28, 1978, cancelled the permit for failure of the permittee to conduct diligently the investigations, examinations, and surveys required by the permit.

The Nebraska Public Power District conducted studies of its proposed Boyd County pumped storage project under a preliminary permit issued March 10, 1975. The permit was for study of a 1,000-MW project, but the application for license filed on February 28, 1978, was for a project having a capacity of 1,336 MW. The project would be located in Boyd County, Nebraska, adjacent to the Missouri River. The lower reservoir would be formed by dikes 40 to 50 feet high located along the Missouri River and adjacent bluffs of the river. An upper reservoir would be formed by an earthfill dam across a natural drainage ravine, providing a head of approximately 440 feet. The FERC, by order issued March 21, 1980, dismissed the application for license without prejudice after the applicant, on October 22, 1979, requested that the application be held in abeyance for a period up to three years. That request was made because of a reduction in the district's future load estimates and the loss of its planned source of pumping power for the project.

On May 2, 1975, the Jersey Central Power and Light Company filed an application for license for the proposed Mount Hope pumped storage project that would be located in northern New Jersey three miles north of the city of Dover on a tributary of the Rockaway River. The project was unique because the lower reservoir was to be underground. The upper reservoir was to be formed by enlarging and raising the level of the existing Mount Hope Lake. The lower reservoir was to be created by excavating a cavern consisting of a grid of tunnels about 2,500 feet beneath the upper reservoir. An existing shaft of an abandoned iron mine was to be used for construction access and another shaft was to be excavated to facilitate construction. The powerhouse was to be in a cavern adjacent to the lower reservoir and was to contain four 250-MW units. It was planned to use single-stage verticle-shaft Francis-type adjustable gate pump/turbines. On June 28, 1977, the company submitted an application to withdraw its application, stating that it had ceased to be the owner of the Mount Hope site. The FERC, by order issued December 28, 1977, approved the withdrawal of the license application.

The Appalachian Power Company, on August 30, 1977, applied for a preliminary permit to study the Powell Mountain pumped storage project. The project would be located on the South Fork of the Powell River and Stony Creek in Scott and Wise Counties, Virginia, in the vicinity of Norton and Big Stone Gap, Virginia. The upper reservoir was to be on the South Fork of the Powell River and was to have a surface area of 790 acres at full pool elevation of 3,200 feet. A dam on Stony Creek was to be constructed to create a lower reservoir with a surface area of 485 acres at full pool elevation of 1,790 feet. An underground powerhouse was to have a capacity up to 3,000 MW. The company withdrew its application on March 12, 1979, by notice to the FERC. The withdrawal notice noted that studies by the U.S. Forest Service showed that part of the area needed for the pumped storage project might ultimately be designated as wilderness and that such designation would effectively preclude development of the project.

APPENDIX B

ADDITIONAL INFORMATION--PUMPED STORAGE ALTERNATIVES

CONTENTS

LIST OF TABLES

LIST OF FIGURES

APPENDIX B

ADDITIONAL INFORMATION--PUMPED STORAGE ALTERNATIVES

B.1 UTILITY THERMAL ENERGY STORAGE (TES)

There are two basic ways to integrate thermal energy storage (TES) into a central baseloading powerplant. One method involves adding a separate peaking turbine to an existing powerplant, and the other method uses the stored heat to heat the feedwater and requires a modified turbine design to allow for large variations in the extraction steam flow. (These two systems are shown schematically in Figures B-1 and B-2.) Thermal energy can be started in many different materials, including aquifers, oil, water/steam, and molten salt. All systems used with power generation must operate near or above 250°C, and the average lifetime for such systems must be between 25 and 30 years.

In a series of Electric Power Research Institute (EPRI) reports (1, 2), 12 systems were found to be the most promising TES concepts in terms of near-term availability and potential for economic feasibility. These systems are outlined in Table B-1. Table B-1 summarizes the energy-related and power-related costs of each system reviewed. Since all cases were for 6 hours discharge, the energy-related costs in dollars per kilowatt-hour ($/kWh) can be found by dividing the energy-related costs by six. TES systems are also ranked in near-term availability*. A scale of 1 to 10 is used, with 1 representing the best possibility of availability and 10 representing the poorest. The systems by storage medium are discussed in more detail below.

- Water. Of the concepts considered, the report found that the TES powerplant with the lowest capital cost and highest overall efficiency used underground cavern storage of high temperature water. The underground cavity systems examined used three means of stress transfer: either concrete (noted in Table B-1 as UG-C-VARP), compressed air (UG-A-FWS), or evaporators (UG-A-EVAP). A disadvantage associated with the underground cavern storage is the geological limitations in site selection.

*The definition of near-term availability used in the ranking judgment is that the technical uncertainties have either been or could be resolved by demonstration in the near future, so that an electric utility customer could order a TES system with reasonable confidence by 1985 for delivery and operation during the period 1985 to 2000.

Figure B-1 Thermal Storage Unit With Separate Peaking Turbine

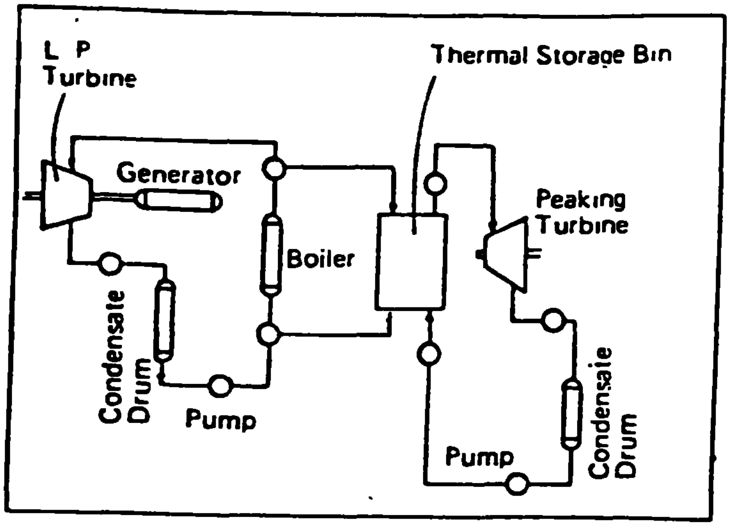
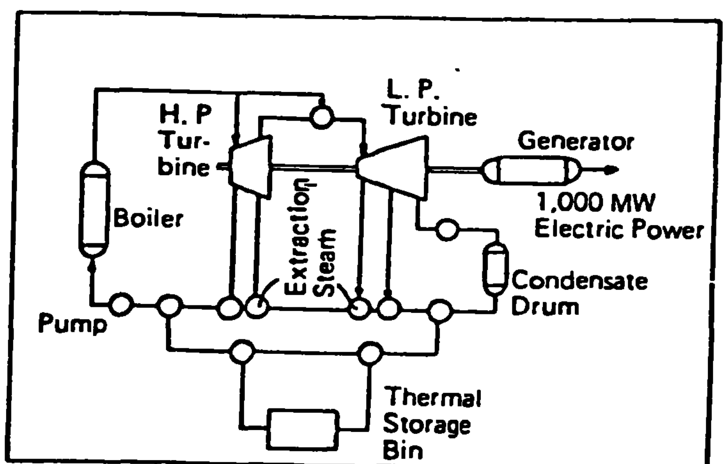


Figure B-2 Thermal Storage Unit in Feedwater Storage Mode



Source: "Exotic Power and Energy Storage," Power Engineering, Vol. 81 (December 1977).

TABLE B-1

Economic and Near-Term Availability Ranking for
Thermal Energy Storage Systems

Selection Number	System	Energy ($/kW)	Power ($/kW)	TOTAL ($/kW)	Economic Rank	Near-Term Availability Rank
1	Prestressed cast iron vessels-feedwater (PCIV-FWS)	461	462	923	6	4
2	Prestressed concrete pressure vessels-feedwater (PCPV-FWS)	524	495	1,019	9	4
3	Steel vessel-feedwater (STEEL-FWS)	1,129	495	1,624	12	1
4	Underground-concrete-variable pressure (UG-C-VARP)	172	477	649	1	3
5	Underground-compressed air-feedwater (UG-A-FWS)	108	667	775	5	6
6	Underground-evaporators (UG-A-EVAP)	180	487	667	2	4
7	AQUIFER	75	855	930	8	6
8	Oil-feedwater (OIL-FWS)	132	538	670	3	5
9	Oil and packed bed/thermocline (OIL/ROCK)	188	541	729	4	3
10	OIL/SALT	---	---	1,400	10	2
11	SALT/ROCK	426	501	927	7	4
12	Phase change material (PCM)	1,000	---	1,500	11	8

Note: Based on 6-hour discharge. Costs are in 1976 dollars.

Source: General Electric Company. Conceptual Design of Thermal Energy Storage Systems for Near-Term Electric Utility Applications, Vols. 1 and 2, EPRI EM-1037, Project 1082-1 (Electric Power Research Institute (EPRI), April 1979).

An advantage of high temperature water is the ability to use it directly in the boiler/turbo generator cycle without such interface equipment as heat exchangers. The major difficulty with water is its relatively high vapor pressure at the storage temperatures of interest, which leads to rather expensive storage vessels. In Table B-1, the cost of systems utilizing prestressed cast iron vessels (PCIV-FWS), prestressed concrete pressure vessels (PCPV-FWS), or steel vessels (Steel-FWS) explain their lower feasibility and availability ranking. While no serious technological obstacles exist, no appropriately-sized demonstration models have been built or tested to date.

- Oil. The EPRI studies examined three types of systems in the oil storage category: oil in feedwater heat (Oil-FWS), oil and packed bed/thermorline (Oil/Rock), and oil and salt (Oil/Salt). All of these systems require heat exchangers that can transfer heat from condensing steam to the oil directly, or an intermediate heat exchanger that can produce high temperature water to be used in a heat exchanger to heat the oil. The latter course provides some added security against oil entering the feedwater loop but imposes added capital costs. The major advantage to this approach is that atmospheric pressure containment is estimated at $35/m^3 (in 1976 dollars) compared to the range (from $250 to $4,000/m^3) for pressure containment. In addition to the concern regarding the flammability of oil is the fact that oil is more expensive than water. It takes about twice as many cubic meters of oil as water to store the same energy over the same temperature range (1).

  Problems still exist in the area of heat exchanger operation, but pilot-size demonstrations of the oil/rock system have been giving some confidence in the near-term availability of this concept for peak-load use (2).

- Molten Salt. Molten salt, particularly HITEC (a Dupont trademark), can be used as a storage medium when three storage tanks are used with salt temperatures at 238°C, 294°C, and 482°C. The lower temperature tanks are larger and use a small temperature drop for effective heat exchange between a sensible heat medium and a condenser or boiler. A fraction of the salt from the middle tank is further heated in the desuperheater, and is later used to provide superheat (2).

Molten salts are available in the near term, but they do have certain disadvantages, not least of which is their high price (considerably more per unit of energy stored than oil). The compatibility of rock and molten salts has not yet been adequately demonstrated. In addition, molten salts have a high melting point, making it necessary to design a method for re-establishing a flow path in case of a shutdown (2).

A molten salt storage concept, advocated by the Martin Marietta Corporation (3), is currently planned for use in solar thermal power system technology.

- Aquifer Storage. Storage of high-temperature water in aquifers (porous layers of water-saturated gravel, sand, or sandstone confined between impermeable layers of the earth) has the potential for an extremely low energy-related cost. Aquifers are available over a wide range of sedimentary geologic areas without excavation or modification. However, the power-related costs for this method of storage are significant since they include the cost of drilling and casing the wells, the cost of pumps and pumping energy, and the cost of heat exchangers. A doublet well concept permits the recycling of hot and cold (or warm) water to and from the same aquifer to minimize resource usage. The temperature rate over which aquifer storage can be effective is unknown; experiments or demonstrations have not been made except at nearly ambient temperatures (2). Aquifers have only a small capacity for daily cycles, and this limits their ability as fast-peaking options. Thus, they are basically suited to longer term storage and limited load-following rather than to peak-load use.

Aquifer storage technology currently is not available. Another disadvantage is that useability will be site specific as some areas are not geologically suitable. Also, there will be constraints against using or endangering aquifers containing potable water. Geochemistry effects versus temperature are not understood nor have they been fully explored; therefore, no near-term tests or demonstrations of significant size and of useful temperatures have been made (2).

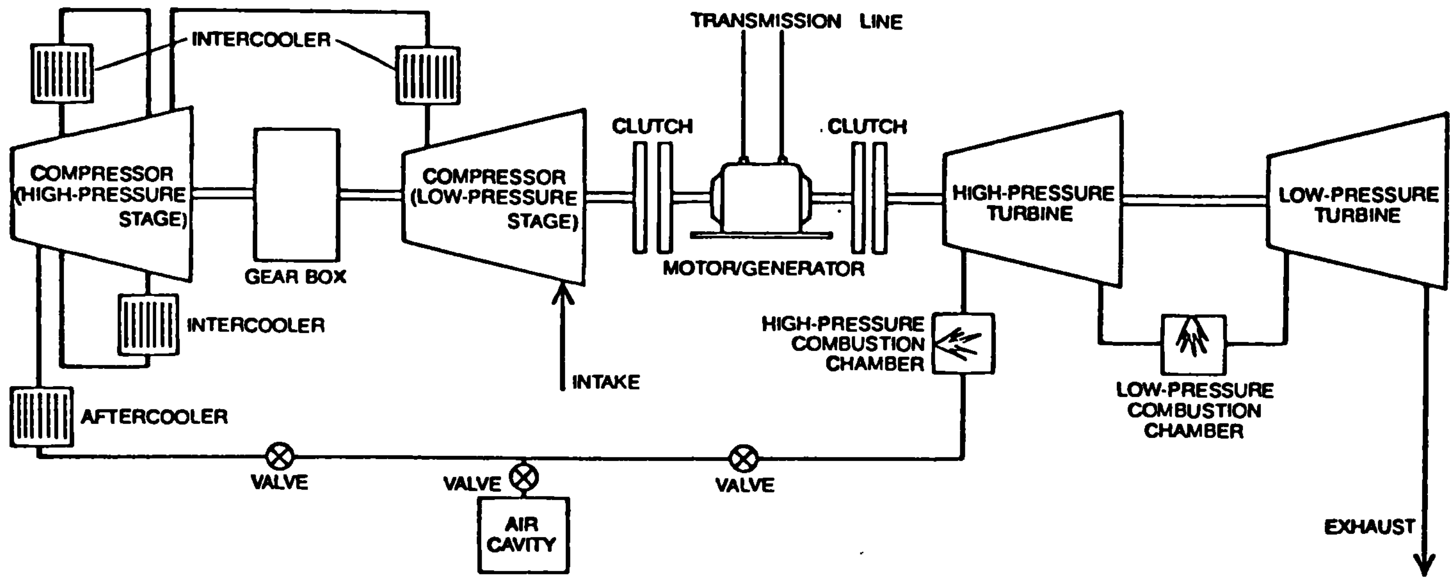
B.2 COMPRESSED AIR STORAGE

Some uncertainties with CAS technology currently are being resolved in Huntorf, West Germany, where the first commercial CAS plant--a 290-MW unit--is in operation. A schematic of the facility is provided in Figure B-3 (4). The facility began operation in December 1978 and uses the combined storage capacity of two salt caverns (about 300,000 cubic meters) for peak-load purposes. During periods of peak demand the air is expanded, heated by the burning of natural gas, and fed through high- and low-pressure turbines that can generate 290,000 kW for up to 4 hours. The cost of the Huntorf facility is given at about 125 million D.M. or $70 million. Table B-2 summarizes the Huntorf and several other current CAS schemes, including costs.

According to a recent article (4), each kilowatt-hour of output at the Huntorf plant requires an electric-energy input of .8 kilowatt-hours for air compression, and a fuel-energy input of 5,300 British thermal units (Btu) for air reheating. Since the start of commercial operations the system has been charged and discharged several hundred times, generating power somewhat in excess of its design rating. All the major technical objectives of this first-of-a-kind installation have been met. Although the economic performance of the Huntorf installation can be established only in actual service over a period of years, a storage facility of this size and construction time (less than 5 years) offers the potential advantage of a smaller investment burden risk to a utility than even the smallest, economically feasible pumped-hydroelectric facility.

An EPRI-sponsored study by General Electric in 1977 (5) developed a conceptual design for a CAS plant sited on the McIntosh salt dome in southwestern Alabama. The plant design has a peak turbine inlet pressure of 40 atmospheres (atm), with the peak air storage pressure ranging from 44 atm (constant pressure storage) to 86 atm (variable pressure storage). A weekly storage cycle was used, and power was 800 MW for 2,000 hours per year. The capital cost of these plants ranged from $196 to $200/kW (mid-1976). The fuel heat rate ranged from lower heating valves (LHV) of 4,140 to 4,330 Btu/kWh. Depending on the storage reservoir design, the system delivered between 1.15 and 1.39 kWh for each 1.00 kWh of charging energy. A modification of these designs was developed for 500 hours annual duty (peaking application). It required a capital investment of about $140/kW, with the same heat rates and charging energy ratios as the 2,000-hour designs. The study concluded that for a substantial range of costs of charging

Figure B-3 Schematic of CAS Facility, Huntorf, West Germany



COMPRESSED-AIR ENERGY-STORAGE PLANT, the first of its kind, is now operating at Huntorf, near Bremen in West Germany. In periods of low demand (typically over an eight-hour night period) air is compressed and stored at a pressure of about 70 atmospheres in two caverns leached out of a salt dome that have a combined capacity of about 300,000 cubic meters. At times of peak power demand the air is expanded through turbines that can generate 290,000 kilowatts of power for two hours. Coolers remove the heat generated during the compression cycle to keep cavern walls from overheating. Heat so removed is replaced by burning some fuel when air is expanded.

Source: Reference (4).

TABLE B-2

Summary of Current Conventional CAS Schemes

	First Generation	Second Generation CAS[9]		
	Huntorf	Brown Boveri	G.E. "McIntosh"	UTRC
Rating (MW/unit)	290	290/220[1]	200 (x 4)	252
Generation (hours)	2	8	8	6
CEF[7]	1.2	1.2	1.156	1.272
FHR (kJ/kWh HHV)[8]	5,700	4,300	4,850	4,617
Cost	DM 100 x 10^6	-	\$158 x 10^6(4)	\$71.6 x 10^6(6)
March 1978 Cost	x 1.5 ≃[2] £129/kW \$225/kW	£129/kW[3] \$225/kW	£129/kW[5] \$225/kW	£182/kW[5] \$317/kW

Note:

(1) 290 MW for 50 Hz operation, 220 MW for 60 Hz operation.

(2) 1.5 factor quoted by BBC to give a 1977/78 price (Currency conversions taken as DM 4 = \$1.74 = £1.0)

(3) Estimate based on a verbal quotation for the surface plant installed in the US and GE costs on the balance--see text.

(4) Cost refers to four units in 1976 dollars.

(5) Unit costs escalated to March 1978 at 6%.

(6) Cost for a single unit in 1976 dollars. A 20% reduction for a three unit installation is quoted by Giramonti (5).

(7) Charge Energy Factor (CEF) = $\frac{\text{Electrical energy returned to the grid}}{\text{Electrical energy consumed during charging}}$

(8) Fuel Heat Rate (FHR) = $\frac{\text{Combustion energy (HHW)}}{\text{Electrical energy delivered}}$ kJ.kWh

Higher Heating Valve (HHV)

(9) United Technologies Research Centre

Source: Reference (8).

power and premium fuel, CAS systems appeared to be economically favored over gas turbines and other utility storage systems.

In another instance, a preliminary assessment by the Potomac Electric Power Company (PEPCO) (6) indicated that the PEPCO system could support 1,000 MW of compressed air energy storage through the year 2005. The projected installation would consist of two 500-MW modules, the first installed soon after 1985 and the second after 1995. By way of example, some 1978 PEPCO estimates of break-even capital costs for CAS on their system (10 hours generation, 1.2 CEF, 4300 FHR are as follows: 1985 commissioning--$335/kW; 1995 commissioning--$578/kW; and 2005 commissioning--$712/kW. The total operating cost of the system was compared with the total cost (capital and operating) of a conventional simple cycle combustion turbine to determine the "break-even" installed cost for the target in-service years.

B.3 BATTERIES

Detailed assessments of the technical and economic prospects of the more promising advanced battery prototypes are to be made at the Battery Energy Storage Test (BEST) facility, jointly funded by DOE and EPRI. The facility, cosponsored and constructed by the Public Service Electric and Gas Company of New Jersey, is to be a national test center for advanced batteries. According to a recent EPRI Journal article, the center "will evaluate battery prototypes with a storage capacity of 5-10 MWh in a utility environment. The first prototype to be tested will probably be the 5-MWh zinc-chlorine battery now being built by Energy Development Associates, a subsidiary of Gulf and Western Industries, Inc. This battery will consist of up to 100 modules, each capable of discharging for five hours at 10 kW. Another prototype, a 5-MWh sodium-sulfur battery, could be ready for testing by 1985" (7).

Despite progress in research, however, these systems will not find significant utility application in this century unless their cost can be reduced to a level competitive with other bulk energy storage and peak-generating methods. Interim cost estimates were calculated by Arthur D. Little (ADL) for EPRI in 1978 for the sodium-sulfur, sodium-antimony trichloride, lithium-iron sulfide, and zinc-chlorine battery systems, using an ADL-developed standard costing methodology (8). Table B-3 lists the estimated costs (all falling within a $34 to $40/kWh range), including principal cost elements for individual battery systems. These costs carry the

Table B-3 Interim Cost Estimates for Advanced Battery Systems
(Based on annual output of 25 approximately 100-MWH batteries)

System: Contractor:	Sodium-Sulfur GE	Sodium-Antimony Chloride ESB	Lithium-Iron Sulfide[1] AI	Zinc-Chlorine[2] EDA
Price ($/kWh)[3]	35.98	39.60	34.27	34.87
Labor[4]	4.54	12.99	2.93	2.98
Materials & Components[4]	25.79	21.07	26.66	26.41
Other[5]	5.65	5.54	4.86	5.48
Factory Cost ($/kWh)	31.23	34.74	30.29	30.29
Investment ($MM)	41.9	40.5	33.2	39.9
Working Capital	24.7	26.1	22.7	23.7
Equipment[6]	17.2	14.4	10.5	16.2
Direct Labor (man yrs/yr)[7]	333	902	203	216
Man hours/kWh	0.242	0.693	0.156	0.159
Floor space (ft^2)	169,000	75,000	184,000	198,000
Battery size (MWh)	105.6	101.2	97.5	104.4
Price/Battery ($MM)	3.80	4.05	3.34	3.64
Annual Sales ($MM)	95.0	101.3	83.5	91.0

Notes
1. Cost estimates for the lithium-iron sulfide system are for cells only, not batteries.
2. Cost estimates for the zinc-chlorine system include some labor for on-site assembly.
3. MWh- and kWh-ratings are based on the capacity of the smallest component unit and do not allow for internal battery power losses.
4. Includes contributions to overhead.
5. Rent, depreciation, return on investment, and taxes.
6. Includes 25% installation charge.
7. Based on an assumed 1920 working hours per year.

Source: Reference (8).

assumption that rated performance capabilities, including adequate service lifetimes, will be achieved. If these developer cost projections can be met, ". . .a five-hour battery system with power-conditioning equipment ($80/kW) will cost just under $300/kW—EPRI's goal for the battery selling price" (8).

In technological terms, the lead-acid battery system could be listed as a near-term candidate; because of its costs, however, significant commercial application by electric utilities is not expected. A design and cost study performed by ESB, Inc., for EPRI (9) analyzed state-of-the-art tubular positive lead-acid battery technology to estimate the selling prices for one 2,500-cycle, 10-MW, 100-mWh load-leveling battery and two 2,000-cycle, 20-MW peaking batteries delivering 60 and 100 mWh. Accessories for the batteries that were necessary to meet the EPRI performance and life requirements, including transportation (500 miles) and installation, were priced respectively at $62 (10-hr. rated), $65 (5-hr. rated), and $73 (3-hr. rated) per kilowatt-hour for the first battery purchased. The report also estimates much lower second battery costs assuming various salvage-reuse credits. Amortized in the price was a battery manufacturing plant investment of $14.4 million for a three-shift operation producing, 1,000 mWh/yr.

Of several advanced battery systems proposed, the two that appear to be the most promising for utility application before the year 2000 are the high-temperature sodium-sulfur battery and the low-temperature Redox battery. The sodium-sulfur battery has molten sodium at the negative electrode and a molten mixture of sulfur and polysulfide at the positive electrode. The electrolyte (electric conductor) is a solid ceramic made of a special form of aluminum oxide known as "beta alumina." Beta alumina conducts sodium ions at high temperatures, and this type of battery would operate at temperatures of 260-315°C (500-600°F). General Electric hopes to have a prototype battery of 5,000 kWh ready for testing at the BEST facility by 1985.

Essentially, the Redox system is a combination or stack of flow cells where chemical energy is converted into electrical energy when two reactant fluids, chromium chloride and iron chloride, are discharged through the stack. In each flow cell a separating membrane keeps the fluids apart but allows for charge transfer. As the fluids circulate through the stack, electrical energy is withdrawn, but the larger ions of iron and chromium are kept separate by the membrane surface (a special cross-linked polymer with a distributed charge, similar to membranes used in dialysis). The process is reversed on recharge. The repulsion caused by the distributed membrane charge is the key to the membrane's ability to avoid clogging and extend its useful life, estimated at about 20 years. Because the reactants can be used indefinitely, only 1 percent of the system's energy is consumed by the circulation pumps, and the process is about 75 percent efficient overall, which is comparable to conventional batteries. Table B-4 (5) provides additional data on the Redox system, including estimated power-related and storage-related costs ($163/kW and $20/kWh, respectively).

Recent EPRI work reported in Energy Technology VII (10) gives costs for 5-hour advanced batteries (72 percent efficient) for a 1992 first commercial service date as: total capital = $630/kW; fixed O&M = $0.3/kW-yr.; and variable O&M = 2.0 mills/kWh (1978 dollars). By way of comparison, the figures given for underground pumped storage (1991 commercial service, 10-hour, 72 percent efficient) were, respectively, $575/kW, $1.5/kW-yr., and zero for variable O&M. Generally, it can be concluded that advanced batteries have the potential to be commercially available for utility storage and peaking purposes in the early 1990's, provided development programs can keep to schedule and costs can be substantially reduced. The facility, cosponsored and constructed by the Public Service Electric and Gas Company of New Jersey, is to be a national test center for advanced batteries. According to a recent EPRI Journal article, the center "will evaluate battery prototypes with a storage capacity of 5-10 MWh in a utility environment. The first prototype to be tested will probably be the 5-MWh zinc-chlorine battery now being built by Energy Development Associates, a subsidiary of Gulf and Western Industries, Inc. This battery will consist of up to 100 modules, each capable of discharging for five hours at 10 Kw. Another prototype, a 5-MWh sodium-sulfur battery, could be ready for testing by 1985" (7).

B.4 DIESELS AND COMBUSTION TURBINES

Beyond 1990 it is possible that synthetic liquids and gases may be used in diesels and combustion turbines for peak loading. The basic technology for gasification and liquefaction is almost two centuries old, but so far plans are not being made for using synthetic fuels for peak loads in diesels and turbines, in part because of the high capital investment required. Figures B-4, B-5, and B-6 show estimates prepared by EPRI comparing conventional oil costs to the projected costs of several synthetic fuel products under different financing assumptions (11).

TABLE B-4

Redox Battery System Data

REDOX FLOW CELL ENERGY STORAGE SYSTEM DATA (R&D DATA, AUG. 1979)

FOOTPRINT: 1MW-10 Hrs. = 10 MEGAWATT-HOURS OF STORAGE

SOLUTION TANKS (ONE MOLAR SOLUTION CONCENTRATION):

2 TANKS REQD., HEIGHT = 20 ft., TOTAL FOOTPRINT = 2340 sq. ft.

POWER CONVERSION UNIT:

4 ft. high x 10 ft. x 9 ft.

PUMPING UNITS:

2 PUMPS REQD., EACH 3 ft. high x 2 ft. x 4 ft.

POWER CONDITIONING AND CONTROLS (INVERTER, TRANSFORMER, ETC.):

6 ft. high x 10 ft. x 8 ft.

TOTAL AREA IN PLAN VIEW:

Area = 2526 sq. ft., Footprint = 4.0 kWh/sq. ft.

Note: It is expected that eventually it will be possible to use two molar solution concentrations. The resulting footprint would then be 7.4 kWh/sq. ft. Using square tanks and two molar solutions, it is believed that the EPRI footprint goal of 8.5 kWh/sq. ft. can be met.

ESTIMATED COSTS:

Power-related cost = $163 per kilowatt
Storage-related costs = $20 per kilowatt-hour

LIFE EXPECTANCY:

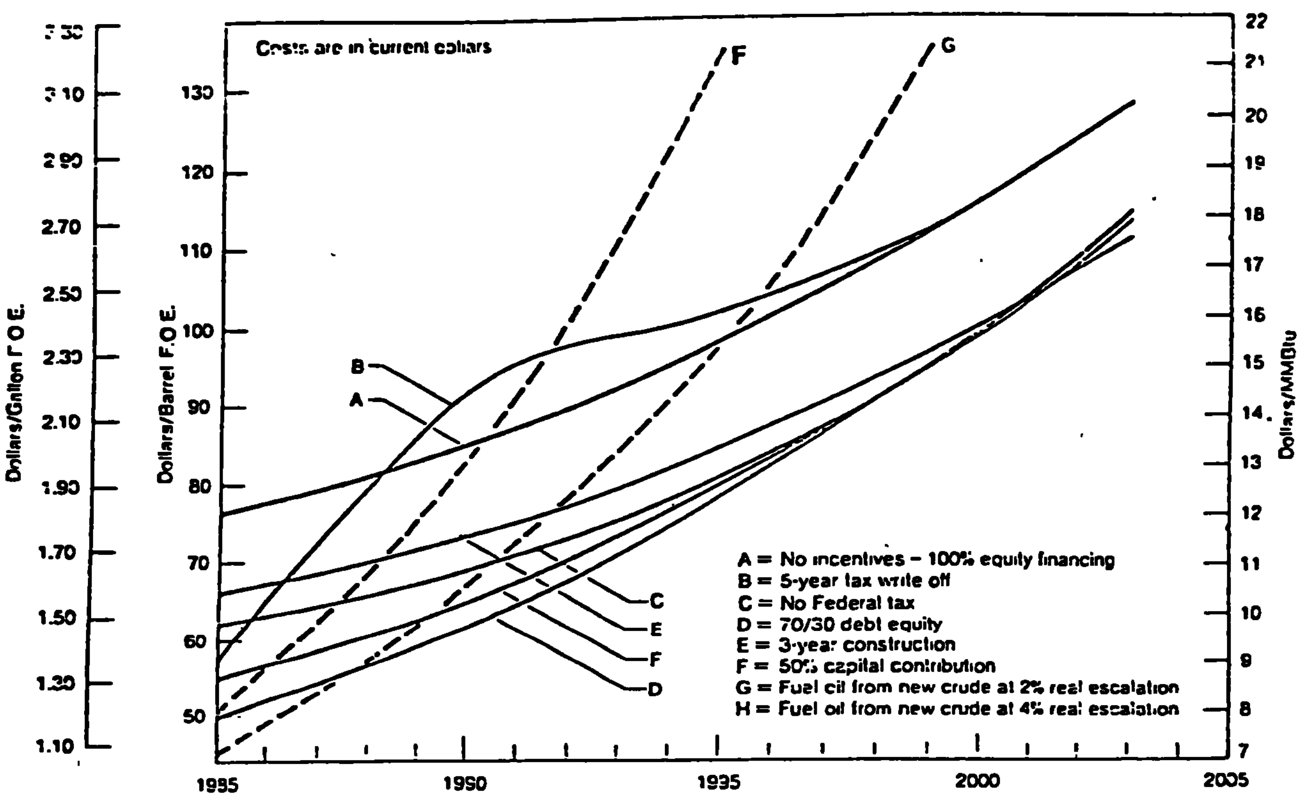
The R&D group responsible for this project anticipates a life of 20 years for the Redox system

ACKNOWLEDGEMENT:

The above data were supplied by Dr. J. Stuart Fordyce, Chief, Electrochemistry Branch, Solar and Electrochemistry Division, NASA Research Center, Cleveland, Ohio 44135--by letter dated August 14, 1979. The author expresses his appreciation.

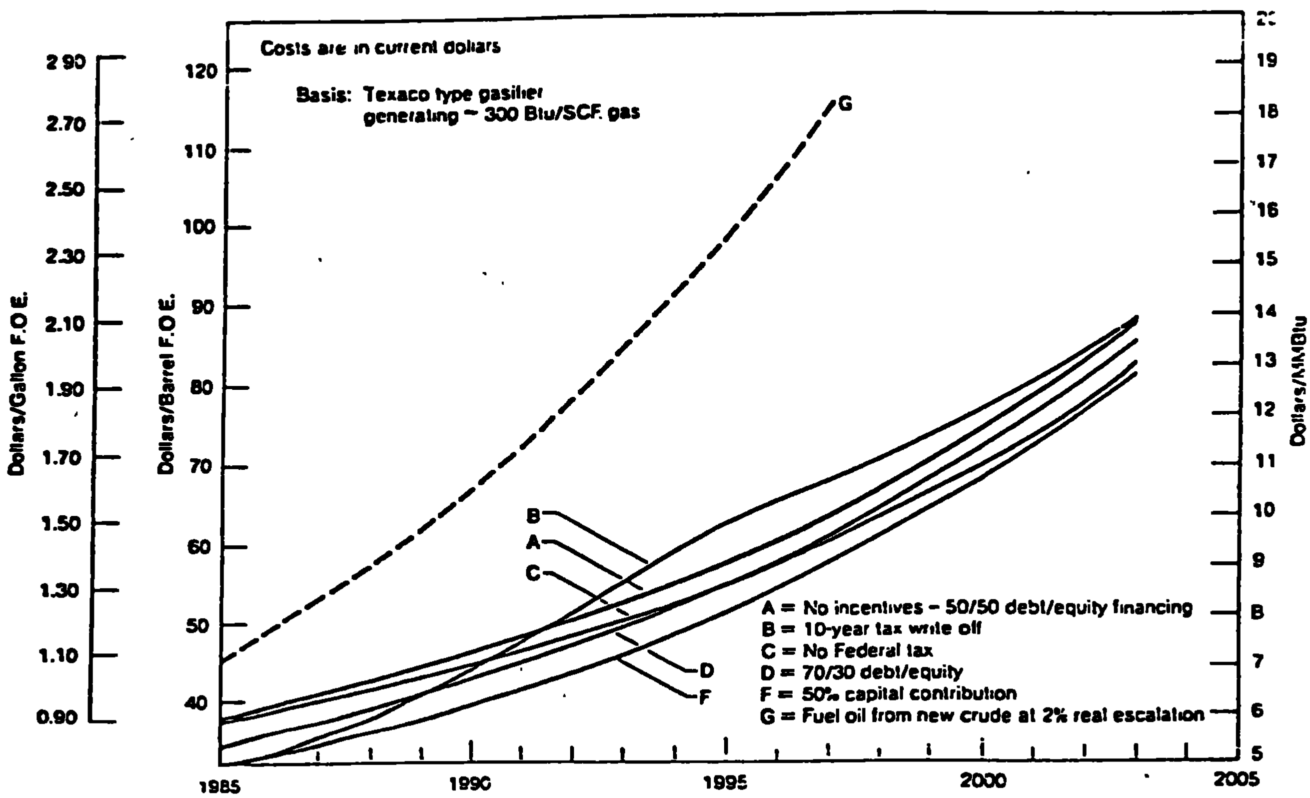
Source: Reference (5).

Figure B-4 Effect of Various Incentives on Coal-Derived Liquids



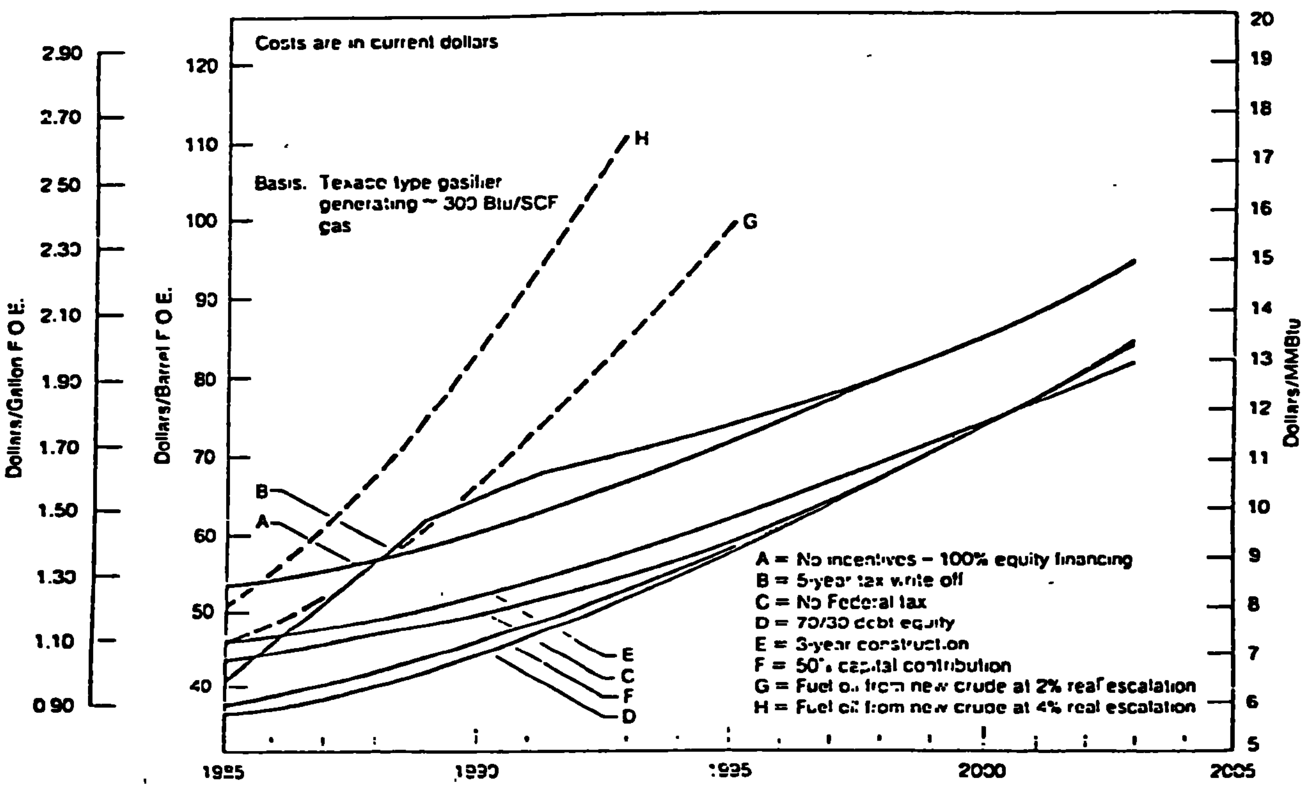
Source: Reference (11).

Figure B-5 Effects of Various Incentives on Intermediate-Btu gas (Utility Financing)



Source: Reference (11).

Figure B-6 Effect of Various Incentives on Intermediate-Btu Gas (Non-Regulated Producers)



Source: Reference (11).

Coal gasification consists of making coal react chemically with oxygen and hydrogen; the coal basically provides carbon fuel in these reactions. In the simplest processes, the oxygen is provided by air, and the hydrogen by steam; in more sophisticated processes, pure oxygen and hydrogen gases may be used. Depending on the type of gasification process used, the gases produced are carbon monoxide (CO), hydrogen (H_2), and/or methane (CH_4), the main component of natural gas. (Carbon monoxide and hydrogen have only about one-third the heat value or energy content of methane.) By-product gases such as hydrogen sulfide are also produced and must be removed to eliminate the release of sulfur to the atmosphere when the coal gas is burned. The use of air for oxygen introduces nitrogen into the gas, lowering the energy content; the use of pure oxygen gas keeps the energy content higher. Generally speaking, the use of steam for hydrogen produces carbon monoxide and hydrogen, while the use of pure hydrogen gas produces methane. However, carbon monoxide can be upgraded to methane using steam.

Coal gasification processes are classified as low-Btu, intermediate-Btu, or high-Btu, according to the energy content of the gas produced. High-Btu gas is compatible with natural gas in that it can be mixed with or substituted for natural gas in existing pipeline systems. It has a heat value of approximately 920 to 1000 Btu/cubic foot and is more expensive to produce than intermediate-Btu gas. Intermediate-Btu gas is suitable for transportation by pipeline but because of its reduced heat value (between 300 and 700 Btu/cubic foot) it is not economical for transport over distances of more than 100 miles. Low-Btu gas is a low-quality (less than 300 Btu/cubic foot) utility fuel intended to be used on site rather than transported (12).

Coal gasification processes face similar environmental problems to those confronting other coal combustion and conversion technologies. These include hydrogen sulfide production, cooling tower blowdown, and runoff from coal storage and solid wastes. In general, these problems can be dealt with by the existing commercial pollution control technologies.

The Lurgi gasifier is the oldest system for coal gasification; the first Lurgi gasifier was built in Germany in 1936 and since then 18 plants have been built. The Koppers-Totzek process is another that has been operating commercially outside of the United States since 1952. Several other processes for converting coal to gas are in various stages of development; among these are the Texaco process, the

Shell-Koppers process, the British Gas Corporation Lurgi Slagging Gasifier, and the HYGAS process. It is not expected, however, that plants will be available on a commercial scale in the United States before 1990 (13).

One factor slowing down application proceedings is that these plants require large capital investments. For instance, the Great Plains Gasification Project in Beulah, North Dakota, is estimated to a $2 billion effort using the Lurgi method and scheduled to begin production in 1984. It will consume 4.7 million tons a year of strip-mined coal, transforming it into 125 million cubic feet of gas per day (the equivalent of 20,000 barrels of oil a day). American Natural Gas, the company building the plant, puts the price of the first gas that is produced there at $6.75 per 1,000 cubic feet--roughly triple today's price for conventional domestic natural gas (14).

B.5 PHOSPHORIC ACID FUEL CELLS

A single fuel cell consists of two electrodes separated by an electrolyte. Fuel is supplied to one electrode and air (oxygen) to the other. An electric potential is established and a current can be drawn as long as fuel and air are supplied. The fuels--either hydrogen or hydrocarbon or coal-derived--react with oxygen only when the external circuit is complete. Single fuel cells connected in series can be used to generate any desired voltage. Connecting them in parallel allows large currents and power outputs.

The first-generation fuel cells being developed for electric utility use rely on phosphoric acid electrolyte and are low-temperature systems, operating at about $350^{o}F$. Small fuel cells in the 10-kilowatt (kW) to 1-megawatt (MW) range have been built and tested in commercial settings.

First-generation (phosphoric acid electrolyte) fuel cells require clean, low-sulfur fuels. The fuel processor for the FCG-1 system being adopted for utility use requires a hydrodesulfurization technique to remove excess sulfur. (The prototype for the FCG-1 system is the 4.8-MW powerplant currently being installed on the Consolidated Edison grid in Lower Manhattan, a $49-million effort (15, 16)). This fuel processor uses an expensive platinum catalyst for the chemical transformation to hydrogen, a process that must substitute a nickel catalyst in the future to become economically feasible (17).

First-generation fuel cell plants have an efficiency of between 37 and 40 percent (heat rate range: from 9,300 to 8,500 (Btu's per kilowatt-hour (kWh)) and the efficiency remains approximately constant over the full load range. Fuel cell development performance goals are: annual replacement of filters and other absorbent materials, overhauls with major parts replacement every 5 years, and a powerplant life of 20 years (18). The initial units are expected to have shorter lifetimes.

Fuel cell powerplants are clean, quiet, and vibration free. The principal environmental consideration is emission-related, but because it is virtually a closed-loop system, the system's operational requirements result in emissions that contain less than one-tenth the pollutants per unit of energy delivered than the Federal standards under the Clean Air Act of 1970 (18).

Commercial feasibility units resulting from the first prototypes are expected to be produced by the mid-1980's at a cost ranging from $400 to $700/kW (1978 dollars). While costs of components have been declining as a result of research and development efforts, the cost of initial units will be dependent on the size of the production facility, the number of units ordered, and the amount of government assistance.

According to data derived from the 1975 Brookhaven National Lab Study (19) and the Public Service Electric and Gas Company study (20), estimated break-even capital cost in the peaking market ranges from $400/kW to over $500/kW as fuel cost increases. EPRI estimates a capital cost of $445/kW (in late-1978 dollars) for a first-generation fuel cell plant that could be in commercial operation as early as 1986, and $475/kW for a more advanced design of higher efficiency (around 45 percent) that could be in commercial operation by 1992 (10).

B.6 HYDROELECTRIC POWER

Subsequent work in the U.S. Army Corps of Engineers' National Hydropower Study has refined the estimated potential first presented in the Corps' initial work (21). Table B-5 and Figures B-7 and B-8 summarize the results of the Preliminary Inventory of Hydropower Resources (22). While the overall estimates of incremental potential have increased, the most striking result is the estimate of the large undeveloped potential (not included in the prior report). Although this study involved a considerably more detailed and comprehensive analysis, the estimates it provides are still essentially upper limits on potential, inasmuch as "Detailed consideration of the social, economic, institutional and environmental constraints associated with hydropower development were not specifically included in the

Table B-5 Preliminary Inventory of Hydroelectric Power Resources

REGION	EXISTING,[1] POTENTIAL INCREMENTAL[2] AND UNDEVELOPED[3] CAPACITY RANGES												TOTAL			
	Small-Scale (.05-15 MW)				Intermediate (15-25 MW)				Large-Scale (Greater Than 25 MW)				(All Sizes)			
	Exist	Incre	Undev	Total	Exist	Incre	Undev	Total	Exist	Incre	Undev	Total	Exist	Incre	Undev	Total
Vol. 1 Pacific N. West																
No. of Sites	93	282	745	1,120	13	36	208	257	73	83	896	1,052	179	401	1,849	2,429
Cap. (MW)	430	642	3,702	4,774	234	700	4,069	5,003	26,141	31,919	259,709	317,769	26,804	33,262	267,480	327,546
Ener (GWH)	2,441	2,234	16,390	21,065	1,216	1,943	14,738	17,897	130,365	33,999	673,918	838,282	134,022	38,175	705,045	877,242
Vol. 2 Pacific S. West																
No. of Sites	111	354	272	737	9	17	26	52	69	43	110	222	189	414	408	1,011
Cap. (MW)	410	574	632	1,616	171	345	509	1,025	9,347	5,109	16,043	30,499	9,928	6,028	17,184	33,140
Ener (GWH)	2,176	1,569	1,640	5,385	837	550	1,059	2,446	37,311	8,729	31,877	77,917	40,325	10,849	34,577	85,751
Vol. 3 Mid-Continent																
No. of Sites	54	779	666	1,499	11	15	63	89	44	59	234	337	109	853	963	1,925
Cap. (MW)	184	850	1,182	2,216	218	317	1,311	1,846	6,087	6,589	27,376	40,052	6,488	7,758	29,868	44,114
Ener (GWH)	1,372	2,138	3,074	6,584	1,006	524	3,142	4,672	22,403	12,481	64,274	99,158	24,781	15,144	70,491	110,416
Vol. 4 Lake Central																
No. of Sites	204	601	551	1,356	10	43	16	69	17	88	59	164	231	732	626	1,589
Cap. (MW)	734	914	926	2,574	180	875	319	1,374	1,689	14,038	6,552	22,279	2,602	15,830	7,799	26,231
Ener (GWH)	3,439	3,128	2,859	9,426	940	2,124	763	3,827	5,475	39,514	17,380	62,369	9,854	44,766	21,004	75,624
Vol. 5 Southeast																
No. of Sites	110	566	265	941	19	29	54	102	98	87	146	331	227	682	465	1,374
Cap. MW)	285	704	1,077	2,066	360	559	1,114	2,033	11,182	11,758	20,969	43,909	11,827	13,021	23,160	48,008
Ener (GWH)	1,000	2,189	3,349	6,538	1,105	1,185	2,863	5,153	36,409	21,466	67,460	125,335	38,514	24,840	71,672	137,026
Vol. 6* Northeast																
No. of Sites	270	2,231	143	2,644	19	26	20	65	27	85	58	170	316	2,342	221	2,879
Cap. (MW)	914	1,771	491	3,176	354	524	400	1,278	4,784	16,446	7,568	28,798	6,053	18,737	8,457	33,247
Ener (GWH)	4,620	6,009	1,531	12,160	1,613	1,533	938	4,084	26,276	81,898	28,610	136,784	32,508	89,440	31,078	153,026
NATIONAL TOTAL																
No. of Sites	842	4,813	2,642	8,297	81	166	387	634	328	445	1,503	2,276	1,251	5,424	4,532	11,207
Cap. (MW)	2,957	5,455	8,010	16,422	1,517	3,320	7,722	12,559	59,230	85,859	338,217	483,306	63,702	94,636	353,948	512,286
Ener (GWH)	15,048	17,267	28,843	61,158	6,717	7,859	23,503	38,079	258,239	198,087	883,519	1,339,845	280,004	223,214	935,867	1,439,085

[1] Existing hydroelectric power facilities currently generating power.

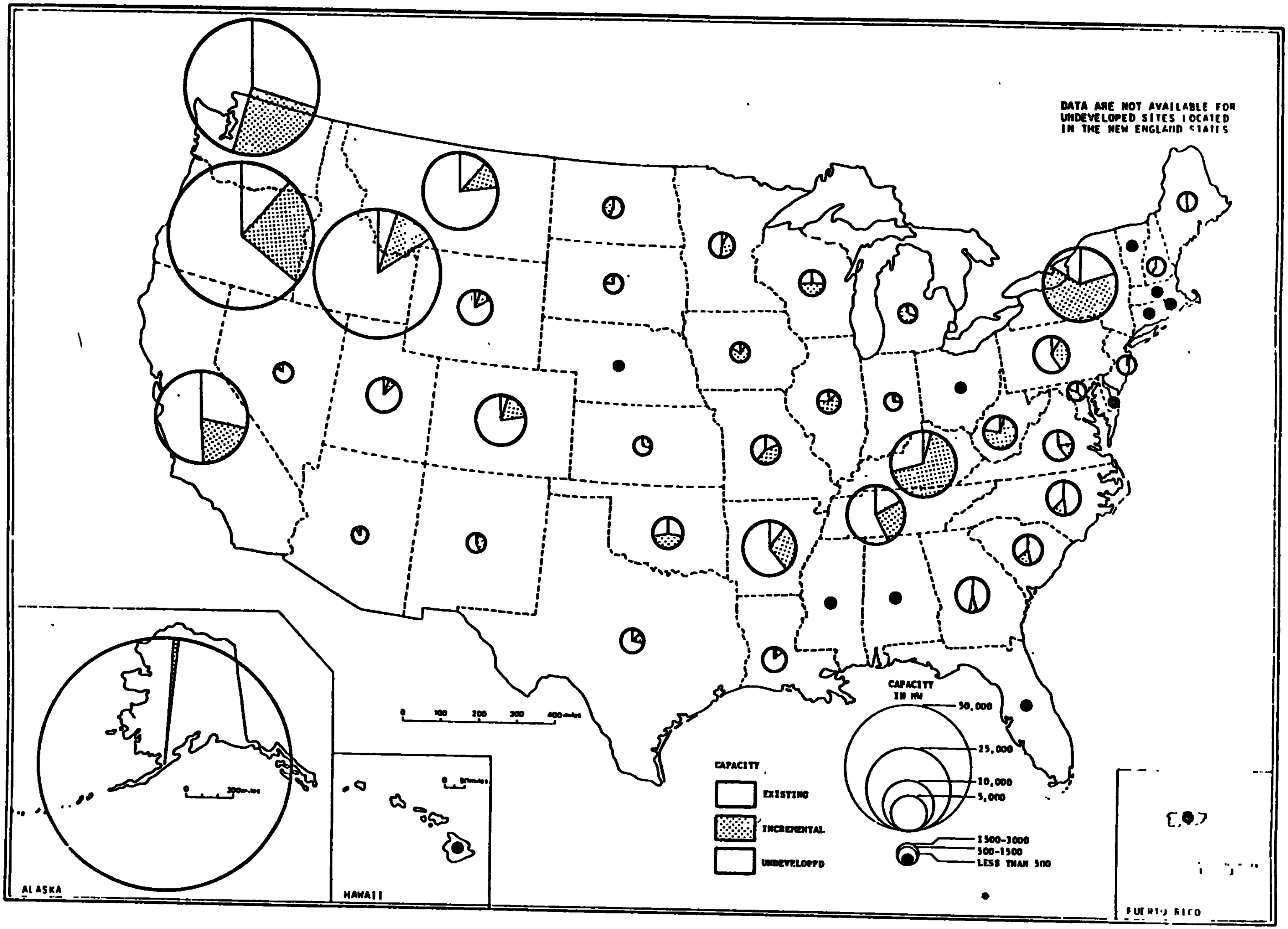
[2] Existing dams and/or other water resource projects with the potential for new and/or additional hydroelectric capacity.

[3] Undeveloped sites where no dam or other engineering structure presently exists.

*Data on undeveloped sites in the New England states are not available (NA).

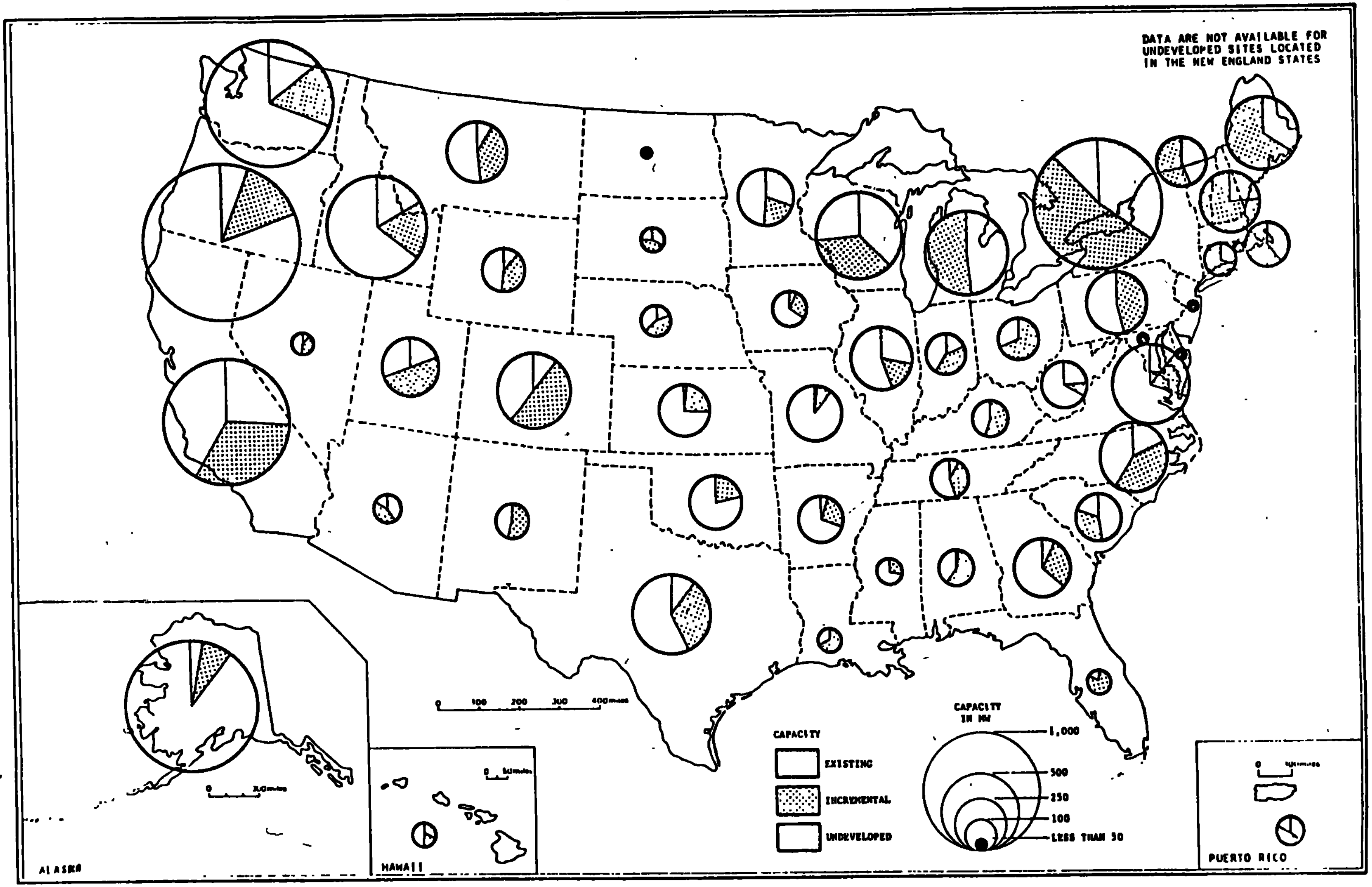
Source: Reference (22).

Figure B-7 National Hydroelectric Power Resources (all sites)



Source: Reference (22).

Figure B-8 National Hydroelectric Power Resources (Small-Scale Sites)



Source: Reference (22).

analysis" (22). These issues have been addressed in subsequent stages of the National Hydropower Study.

These estimates of capacity and energy potential, summarized by region in Table B-5, are listed, site by site, in the Preliminary Inventory. This provides a data base from which the operational mode and/or capacity factor of potential new hydro capacity additions can be assessed. In addition, the Federal Energy Regulatory Commission (FERC) maintains a list of hydropower potential based on license applications, feasibility reports, and other data (23). Obviously not all developable sites will be suitable for peak-load power generation. Some will be constrained by seasonal flow variations or impoundment limitations; others will be better suited to intermediate- or base-load development.

Environmental impacts produced by installing hydroelectric generating facilities are highly site specific. For instance, development of a store-and-release hydroelectric capacity at an existing dam could produce water fluctuations possibly resulting in additional impacts such as:

> ...decreased spawning and food production and degradation of wetland habitats above the dam; with bank erosion, bottom scouring, loss of cover and food, and flow regulation with periodic flow shortages dominating the potential downstream fisheries impacts....Impacts typically associated with newly-constructed hydroelectric dams include those mentioned above, plus creation of a reservoir habitat with changes in water quality and species composition of aquatic organisms, and loss of stream and terrestrial habitats and spawning sites above the dam; upstream and downstream migration blockage and (occasionally) embolism in fish below the dam. More detailed treatments of hydropower impacts on fish and wildlife resources are given in the (U.S. Fish and Wildlife) Service's Hydroelectric Power Project Review Manual and other reference sources cited therein (23).

With regard to the impact on hydropower development as a result of public laws designed to preserve and protect scenic and free-flowing conditions on selected U.S. rivers, a recent Government Accounting Office (GAO) report stated: "As of February 1979, 28 rivers had been designated as wild and scenic (for example, under the Wild and Scenic Rivers Act). FERC estimates these designations preclude the development of 12,750 MW of hydroelectric capacity and 41.5 billion kWh of energy. Fifty-nine river segments are currently under study by the Departments of the Interior and Agriculture. FERC estimates these rivers preclude the hydroelectric development of 9,500 MW of capacity and 29.4 billion kWh in energy (24)."

Streamflow characteristics in general, and the wide range of potential capacity factors in particular, combine with capital investment to yield an even larger range of potential power costs. To illustrate this range, several examples are considered. Table B-6 summarizes cost estimates for new large (greater than 25 MW) projects in New England--estimates made as part of a regional hydropower assessment (25). The table lists only those potential developments that were estimated by the work group to have a benefit/cost ratio greater than 0.8. Note the wide range in dollars-per-kilowatt capital costs (which are in late-1975 dollars).

As to capital costs for small- and intermediate-scale developments at existing unpowered dams, Acres American, Inc., estimates the cost of new hydro currently to be in the general range of $700 to $1,500 per kilowatt (1976 dollars) and notes: "For the addition of power facilities alone at existing sites, estimated costs would currently range from about $400 per kW for 10,000 kW units at 120 feet head to $1,800 per kW for 500 kW units at 20 feet head." Tibbets-Abbett-McCarthy-Stratton estimates a similar though somewhat lower cost range (e.g., $400/kW for a 10-MW unit at 43 feet head, $1,800/kW for a 500-kW unit at 12-1/2 feet head) for projects requiring "minimal civil works" (26).

B.7 SOLAR PHOTOVOLTAIC ENERGY

Solar photovoltaic cells are discs of transistor-like materials that generate DC electricity at low voltage when exposed to sunlight. The output of such cells, which are grouped and wired into flat plate or concentrator collector panels, arrays, and modules, must be converted to AC and the available voltage stepped up before it can be transmitted and/or used for utility applications. Manufacturing methods under investigation include ribbon or single-crystal growth, spray, and thin-film or vapor deposit. New manufacturing methods, such as the continuous ribbon process, have great potential to simplify production and reduce crystal loss during manufacturing. Theoretical efficiencies for the various kinds of cells range from 8 percent for some of the cadmium sulfide/copper sulfide devices to 28 percent for the gallium arsenide thin-film cells. However, to date, laboratory tests have only achieved efficiencies from 5 percent to 22 percent for cells for use in concentrated sunlight. Commercial versions of silicon and thin-film cells currently perform with efficiencies up to about 10 percent.

The solar radiation resource is greatest in the Southwest and least in the Pacific Northwest. Table B-7 shows annual average total and direct radiation at

TABLE B-6

Estimated Capital Costs for New Hydroelectric Developments in New England (1975 Dollars)

River	Project	Installed Cap. kW	Capacity Factor	Average Annual Output (1,000 kWh)	Initial Cost ($1,000)	Initial Cost ($/kW)
St. John	Dickey	760,000(8)	.11	849,000	$463,000	558
St. John	Lincoln School	70,000(2)	.37	305,000		
W. Branch	Arches	50,000	.21	94,250	$ 34,207	684
Penobscot	Basin Mills	50,000	.21	93,150	$ 46,993	940
Kennebec	Madison (High Dam)	80,000	.21	146,800	$ 48,871	611
Magalloway	Aziscokos	25,000	.22	49,080	$ 11,875	475
Androscoggin	Pontook	50,000	.20	88,410	$ 40,560	811
Androscoggin	Pulsifer Rips	25,000	.19	42,460	$ 24,799	992
Merrimack	Moores Falls	50,000	.20	101,000	$ 56,239	1,125
Connecticut	Enfield	60,000	.50	261,900	$ 94,367	1,573
West Branch	Sourdnahunk	50,000	.23	109,450	$ 54,588	1,092
Penobscot	Winn	50,000	.20	89,170	$ 54,749	1,095
Kennebec	Cold Steam	120,000	.25	259,350	$125,597	1,047
Pierce Pond Str	Pierce Pond	220,000	.23	459,000	$217,154	987
Saco	Steep Falls	30,000	.18	47,690	$ 32,652	1,088
Pemigewasset	Livermore Falls	35,000	.23	69,800	$ 44,295	1,266
Winnipesaukee	Tilton	20,000	.17	29,600	$ 15,969	798
Contoocook	River Hill	30,000	.24	63,700	$ 39,501	1,317
Deerfield	Meadows	30,000	.16	41,800	$ 29,310	977

Source: New England Federal Regional Council. A Report on New England Hydroelectric Development Potential (June 1976).

TABLE B-7

Average Annual Total and Direct Solar Radiation for Various Collector Geometries, kW/m^2

Geometry	Phoenix, AZ		Albuquerque, NM		Fort Worth, TX		Omaha, NB		Nashville, TN		Blue Hill, MA	
	Total	Direct	Total	Direct	Total	Direct	Total	Direct	Total	Direct	Total	Direct
Fixed horizontal	0.245	0.177	0.240	0.175	0.194	0.118	0.172	0.103	0.167	0.092	0.146	0.076
Fixed, $L-5^{o}$ tilt	0.268	0.204	0.266	0.204	0.208	0.136	0.191	0.124	0.180	0.107	0.159	0.094
Tracking, E-W axis	0.285	0.221	0.288	0.233	0.211	0.149	0.203	0.136	0.187	0.117	0.169	0.104
Tracking, polar axis	0.339	0.275	0.343	0.283	0.258	0.188	0.241	0.178	0.213	0.145	0.193	0.136
Tracking, two axes	0.349	0.287	0.352	0.295	0.264	0.196	0.248	0.186	0.218	0.150	0.199	0.136

Source: Reference (27).

six locations for various collector geometrics (27). Since the peak rating of a photovoltaic array is generally given in terms of its output in insolation of 1 kilowatt per square meter (kW/m^2), these data can also be interpreted as array capacity factors. Thus, a two-axes tracking concentrator system in Blue Hills, Massachusetts, would have a capacity factor of 0.136, while a fixed (latitude minus 5 degrees) flat array system in Phoenix, Arizona, would have a capacity factor of 0.268. In practice, output would be further reduced by DC/AC inversion (typically, about 90 percent efficient), and by the use of storage (e.g., batteries), if any.

A study by General Electric Company for EPRI (28) estimated the capacity displacement potential of several types of photovoltaic systems in three electric utility areas: New England Electric system, Florida Power & Light Company, and a combination of the Arizona Public Service Company and the Salt River Project. At a 5-percent penetration level of photovoltaics into the system, the estimated effective capability ranged from below 20 percent of rated capacity for a residential flat array in Florida to nearly 60 percent of rated capacity for a parabolic trough concentrator system in Arizona. (The average estimated effective capability is about 35 percent.) However, as noted above, the capacity displacement includes not only peak-load but intermediate- and even base-load capacity as well.

The integration of photovoltaic systems into a utility grid is being addressed in several (50 to 200 kW) experiments. For example, Pacific Gas and Electric Company has announced plans for a 50-kW experimental photovoltaic peaking facility in San Ramon, California. The capital cost of the plant, scheduled for completion in the early 1980's, was reported to be about $20,000 per kilowatt, although it is expected that this will be revised upward. Arizona Public Service Company is installing a 200-kW AC (225-kW DC) photovoltaic system at Sky Harbor International Airport in Phoenix. The estimated cost of the unit, due to be completed shortly, is $5.8 million or about $29,000 per kilowatt. Future photovoltaic plant costs should be substantially lower.

Current DOE planning envisions four central station system application tests during the 1983-1986 period, each expected to be 2-MW in size. The objectives of these experiments will include technical verification as well as obtaining operating experience in a utility environment (29).

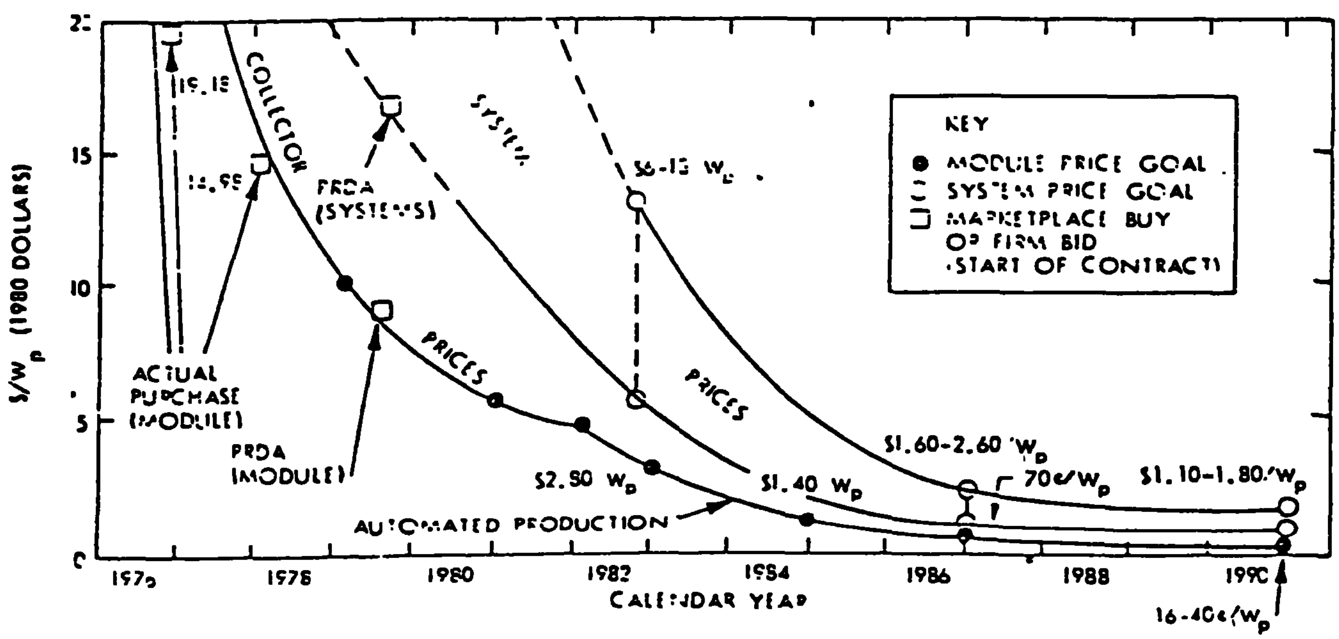
Figure B-9 shows the DOE price targets for photovoltaic collectors and systems (in 1980 constant dollars), as well as the flat plate collector purchase price history (29). As these goals apply to both flat plate and concentrator technologies, direct comparisons require some normalization; flat plate collector price goals do not include supporting structures, an integral part of concentrator collectors. The DOE commercial readiness price goals for complete systems (in 1980 dollars per peak kilowatt of system output) are:

- $1,600-$2,200/kW for residential applications by 1986
- $1,600-$2,600/kW for intermediate-load centers by 1986
- $1,100-$1,800/kW for central stations by 1990.

This large difference between the photovoltaic array cost and the total system cost results from: supporting and installing the arrays, power conditioning, such as DC/AC inversion; and energy storage. As a rough example, let us assume that a photovoltaic array price of $600 per peak kilowatt (1979 dollars) is achieved by the mid- to late-1980's. The cost of mounting and installation is reported as being $45 to $60/m^2 currently (in 1977 dollars), and is estimated at $30/m^2 to $50/m^2 in the future. This would add about $400 to $700/kW to the cost. If used, limited storage would cost $100 to $200/kW (e.g., 2.5 to 4.0 kilowatt-hours of storage batteries per peak kilowatt at $40 to $50/kWh). The DC/AC invertor and other electrical equipment would cost about $200 to $300/kW. Accounting for invertor losses, such a system would have a total base capital cost of about $1,200 to $1,800 per peak kilowatt. (At $1,200/kW for the photovoltaic arrays and higher range costs for other items, the system base capital cost would be about $2,400 per peak kilowatt.) This does not include the cost of backup capacity for cloudy days.

In 1975, module prices ranged from $25,000 to $90,000 per peak kilowatt. Today, an array with similar performance, and far better reliability, sells for about $10,000 per kilowatt. Because array costs are dropping, the worldwide market for photovoltaics is beginning to expand. By 1982, DOE anticipates the market will become large enough to justify significant automated mass production of photovoltaic systems. This will, DOE believes, open up new markets, accelerate sales, and, with experience and production scale-up, realize their price goals and large-scale commercial deployment of systems (29). However, in a study funded in part by DOE, an 11-man study group of the American Physical Society (whose members are responsible for much of the research work in this field) estimated that photovoltaic systems would produce 1 percent or less of the U.S. electric energy

Figure B-9 Photovoltaics Module and System Program Goals



Source: Reference (29).

needs by the year 2000 (30). A report by General Electricfor EPRI (28) estimated a similar level of about 0.4 percent in 2000 and about 1.4 in 2010.

B.8 OIL PLANT CONVERSION

Conversion to coal can significantly reduce operating costs; however, the cost of conversion to coal is sensitive to a number of factors, including: transportation and coal storage systems, plant layout considerations, the size and age of the plant, whether or not it has operable coal-handling equipment and boilers, and the additional emissions control equipment needed. For example, plants that were originally designed to use coal will have to conform to air quality standards and may require the addition of scrubbers and other pollution control systems. Plants designed only for oil would require major redesign of the boiler and fuel facilities. An Engineering Societies Commission on Energy report describes an investigation of powerplant coal conversion and the opportunities and constraints of various types of utility coal conversion in New England (31).

Coal/oil mixture (COM) combustion in a utility boiler involves the preparation of a slurry containing oil and pulverized coal, which can be pumped and burned in much the same way as heavy residual oil. One technical problem related to COM involves the proportion of coal to oil in the mixture. A limit of 50-percent coal is necessary; a higher coal percentage results in high-viscosity problems and creates the potential for increased erosion effects. Florida Power Corporation is currently burning COM in its 380-MW Crystal River Unit 1, using coal comprising 45 percent of the coal/oil mixture by weight (32).

Another problem involves the type of boiler being used. Boilers originally designed for coal are the best candidates for COM fueling, especially if the boiler and its auxiliary equipment have been maintained since conversion from coal to oil. Testing for DOE being done by Davy McKee Corporation's Coal Combustion Department indicates that heat release rates and the temperatures of heat transfer surfaces might lead to oil unit derating of from 5 to 20 percent. In 1979, Davy McKee Corporation estimated that the cost of converting a 100-MW unit designed for coal would vary from $350,000 to $1.1 million (32).

So far, the majority of COM work has been combining coal and No. 6 fuel oil, although No. 4 fuel oil has also been used. These heavy oils are suited primarily to intermediate- to base-load generation and not to peak loading. COM work also involves the use of up to 0.1 percent of an additive to enhance the stability of the coal in the oil.

Another alternative for reducing the usage of coal and gas in utility boilers is the supplementing of conventional fuels with refuse-derived fuel (RDF). In a refuse-derived solid fuel manufacturing plant, the raw waste is processed into a solid fuel that can be burned. Raw solid wastes are dried and shredded or milled to reduce the size of particles. The waste is then air classified into two fractions; the light portion, made up primarily of dry combustive organics, is known as RDF. RDF can replace between 10 to 50 percent by weight of coal or oil fuel, but it may also reduce the efficiency of some boiler types (17). While several utilities are experimenting with RDF, substantial cost savings over the use of conventional fuels are not expected in the study time-frame (33).

Producing liquid fuels from coal can be accomplished in a process where coal is liquefied by dissolving it in a solvent under heat and pressure; hydrogen is then added, and ash and sulfur are separated from the resulting hot liquid. The SRC-I process involves cooling the liquid to turn it into a relatively ashless, low-sulfur solid that can then be used to fire powerplants as either an SRC/oil slurry or as a 100-percent SRC fuel.

Bechtel, in a study prepared for EPRI in 1979 (34), estimated the capital costs associated with retrofitting a 500-MW, oil-fired plant to fire solid SRC to be \$175/kW and \$73/kW for SRC/oil slurry firing. As SRC-I is more expensive than conventional coal as a fuel, its use will probably be limited to base-load or intermediate-load operation.

Another product of the SRC process is SRC-II, a liquid produced by adding more hydrogen to the initial SRC liquid. Recently updated estimates by DOE place the cost of the Gulf Oil's planned Morgantown, West Virginia, SRC-II plant at \$1.6 billion, double the previous 1977 estimate (35). According to DOE, the doubled cost estimates result because the 1977 estimates referenced a generic plant. Those estimates were subsequently revised for a specific plant. While it is conceivable that such plants will be in commercial operation before 2000, SRC-II is a heavy fuel oil that would most likely be used essentially for intermediate- to base-load generation and not for peak loading.

Figure B-4 shows estimates of costs for coal-derived liquids under various incentive scenarios (11). The EPRI chart indicates that these liquids could become economically competitive after 1990. Overall, their price in the 1990's is unlikely to be substantially below that of conventional oil.

Synthetic liquids can also be derived from shale and tar sands. After processing, both substances can be upgraded and refined into useable fuels. Shale oil development will be complicated (for technological and environmental reasons) and expensive, and tar sand recovery will be more difficult. Figure B-10 shows the effects of various incentive scenarios on oil shale prices as forecast by EPRI (11).

B.9 COAL GASIFICATION/COMBINED-CYCLE (CGCC) PLANTS

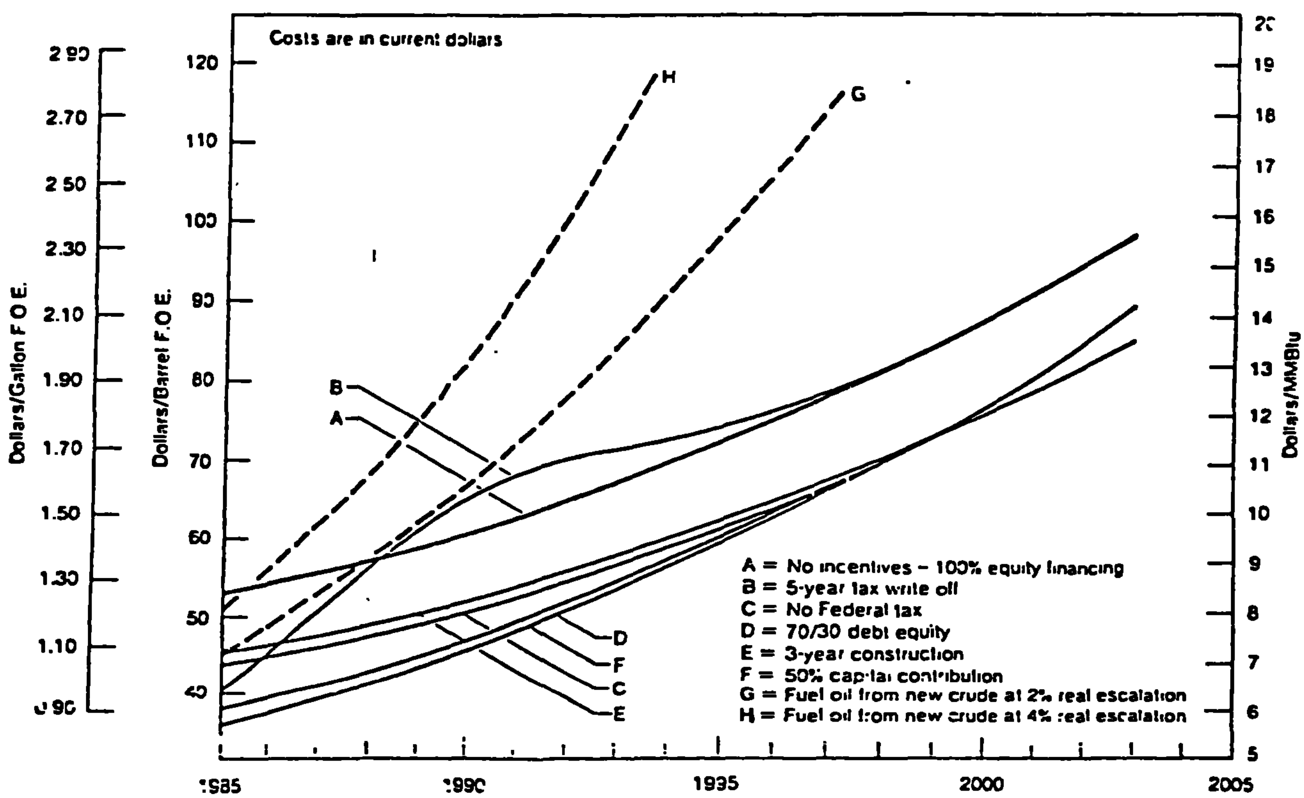
Currently, General Electric, Bechtel, Texaco, Southern California Edison, and EPRI have committed themselves to the Cool Water Project, a $300-million, 100-MW venture to be built on the Southern California Edison system with a startup targeted for late 1983. The unit will employ a 1,000-ton-per-day Texaco gasifier and will be the only extant demonstration of integrated CGCC power generation in the United States (36, 37). It will be fueled by low-Btu gas and is expected to operate in a load-following mode. Generally, it is thought that CGCC systems will operate most efficiently in either a base- or intermediate-load situation (38). In addition, a number of utilities are conducting studies related to ordering CGCC units or retrofitting gasifiers to existing units.

EPRI estimates that a plant similar to the proposed Cool Water Project could have a thermal efficiency ranging from 37 percent for early commercial units to 42 percent for advanced designs, as compared to the 34 to 36 percent achievable with a conventional coal-fired plant with stackgas scrubbers (39). A combustion-engineering study provided similar estimates (see Table B-8). Capital costs of early demonstration plants, however, will be significantly higher than those for conventional coal-fired plants. Commercial CGCC units using a Texaco (or similar) gasifier system are expected to have a capital cost around 10 percent higher than a conventional coal unit with scrubbers (Table B-8) (10), although such units may see first commercial service as early as 1990. It might be possible to reduce capital costs by around 20 percent in advanced designs using improved gasifier technology, but such units are not expected to be commercially available before 2000 (10).

B.10 FLUIDIZED BED COMBUSTION

The largest atmospheric fluidized bed combustion (AFBC) unit built to date is DOE's 30-MW Rivesville plant in West Virginia. Operation so far has been limited,

Figure B-10 Effects of Various Incentives on Oil Shale



Source: Reference (11).

TABLE B-8

Operating Cost Data for Nominal 600 MW Plants

Plant	Coal/Scrubbers	Gasifier/Steam	Gasifier/Combined 2200 $^{\circ}$F Gas Turbines
Heat rate, Btu/kWh	9,456	9,666	8,223
Efficiency, %	36.1	35.3	41.5
Net MW	554.6	561.7	578.1
Plant cost, $/kW	793	833	881
Annual Costs, Mills/kWh			
Fixed charges at 18%	20.4	21.4	22.7
Labor and materials[a]	8.1	4.4	4.0
Coal @ "average" $\$3.00/10^6$ Btu[b]	28.3	29.0	24.7
Levelized cost of electricity, mills/kWh	56.8	54.8	51.4

[a] Constant 1979 dollars.

[b] Coal, labor, and material costs escalated and levelized for 30-year plant life with declining load factor after 15 years, in each case.

Source: "Coal Gasification Process for Clean Fuel Gas," Energy Technology VII, Proceedings of the 7th Energy Technology Conference, Washington, D.C. (June 1980).

due to problems experienced with startup, coal feeding, support plate thermal stress cracking, and an air preheater fire. Recently, a 100,000-pound-per-hour (the equivalent of about 10 MW). AFBC unit went into operation at Georgetown University. This demonstration project, funded largely by DOE's fluidized bed combustion program, is used to produce steam to heat university buildings (41).

In addition, a 20-MW pilot AFBC powerplant ordered by the Tennessee Valley Authority (TVA) is scheduled to go into operation in 1983, and conceptual design work has been completed for a 200-MW demonstration plant planned by TVA for the mid- to late-1980's. Additional research, development, and demonstration work on AFBC systems also is continuing at a number of facilities both here and abroad.

For a large (about 800 MW) atmospheric fluidized bed powerplant, detailed estimates of the base capital cost are equivalent to between \$445 and \$490/kW in 1979 dollars (42, 43). EPRI estimates a complete capital cost of about \$700/kW for a 500-MW AFBC plant, or about 87.5 percent of that for a conventional 500-MW coal plant (44). Overall, conceptual design studies generally estimate a mature capital cost between 80 and 93 percent of that for a conventional coal plant with scrubbers. The cost of early demonstration units will be significantly higher. The heat rate of AFBC plants is estimated at between, 9,500 and 9,900 Btu/kWh.

B.11 COGENERATION

The term cogeneration applies to the production of both electricity and useful steam or heat from the same fuel. By far the most common method is so-called "topping-cycle" cogeneration in which high-temperature steam or gas is expanded through a turbine to generate electricity and useful thermal energy is recovered from the exhaust steam or gas. Currently, cogeneration systems use steam turbines, combustion turbines, or diesels for power generation; oil and gas are the most common fuels, though some facilities use coal. Basic parameters are summarized in Table B-9 (40).

When industries began to use electricity about 80 years ago, many cogenerated their own heat and electricity. As recently as 1950, industrial self-generation provided 15 percent of the nation's electricity. By 1977 this rate had fallen to 4 percent because utility generation grew rapidly while industrial generation stagnated, in large part due to decreasing utility costs (45).

TABLE B-9

Cogeneration Cycle Configurations

Cycle	Size MWe	Fuel	Elect Steam (kW/10⁶ Btu)	FCP (Btu/kWh)	Process steam press (psig)	Total plant installed cost * ($/kW)	Pollution	Controls	General system notes
Gas turbine & waste heat boiler	0.5 → 75	Gas #2 oil Treated residual SNG (low Btu)	200	5500	150-600	$350-400	NO_x	Water or steam injection	1000 F exhaust can be used as clean hot gas
Diesel engine & waste heat boiler	0.5 → 25	Gas #2 oil Treated residual	400	6500	15-150	$350-500	NO_x Partic-ulates	Tuning Steam injection Baghouse	Efficient at part load and in small sizes High power/steam ratio
Steam boiler & turbine	> 1	Nuclear Any oil Coal Wastes	45 → 75	5000	15-600	$500-600	SO_2 Partic-ulates NO_x	Low S fuel, scrubber Precipitator	Efficient at part load
Combined cycle & waste heat boiler	1 → 150	Gas #2 oil SNG	150	5000	15-900	$350-450	NO_x	Water or steam injection	Variable power/steam ratio Back-pressure steam turbine
Steam bottoming	0.5 → 10	Waste heat	N.A	0	N.A	$400-600	N.A	N.A	Efficient at part load
Organic bottoming	0.6 → 1	Waste heat	N.A	0	N.A	$400-700	N.A	N.A	Efficient at part load Uses exhaust Prototypes available Requires cooling water

*late 1976 dollars

Source: Reference (40).

One operating arrangement for cogeneration facilities is electric utility-owned plants selling process steam or heat to adjacent or nearby industry. However, it is often difficult to find sites that are both environmentally acceptable (usually rural) and that have an adequately large industrial steam market. (An example of such an arrangement is Consumers Power Company's Midland nuclear plants, under construction in Michigan, where steam is to be sold to Dow Chemical.) The primary potential, however, is believed to lie in the development of cogeneration facilities at industrial plants with utilities buying excess electricity or steam for power generation. In this sense, the impact of cogeneration (and other user self-generation) on utilities will be largely in terms of its potential for reducing demand and providing some additional electricity.

A number of factors limit the feasibility of developing the potential for cogeneration (siting restrictions and regulatory requirements, size of the facility, type of fuel to be used, whether the facility will yield an attractive return on investment, etc.). An analysis of the impact of these factors and of possible government actions (higher investment tax credits, faster depreciation, regulatory and fuel tax exemptions, eased environmental standards, etc.) has been performed by Resource Planning Associates (RPA) (46). Of a technically suitable cogeneration potential of 50,000 to 100,000 MW in the United States, RPA estimated that 6,000 MW of cogeneration capacity (beyond that already installed) would be economically feasible to develop by 1985 without government action. Government action was estimated to be capable of increasing this figure by 2,000 to 6,000 MW. These figures assume a capacity factor of approximately 80 percent.

Removal of institutional barriers (47) is a principal focus of the Public Utilities Regulatory Policies Act (PURPA) of 1978. Pursuant to PURPA, the Federal Energy Regulatory Commission (FERC) has issued rules (48) exempting cogenerators and small producers from state and Federal regulations that apply to utilities. The rules also require utilities to buy their excess power at rates equal to what it would cost to generate the electricity themselves or to buy it elsewhere, and to provide backup power on a nondiscriminatory basis. A significant factor will be whether cogeneration facilities will be planned and operated so as to displace capacity needs of utilities, i.e., whether rates paid by utilities can or will include capacity value as well as energy value.

B.12 SOLAR THERMAL POWER

A solar thermal electric powerplant is similar to a conventional powerplant, but the steam driving the turbine is generated by heat focused by the sun's rays rather than by burning fuel. For utility applications, development efforts are concentrated on the central receiver system (power tower) rather than the distributed collector system (e.g., parabolic troughs) because of the potential for higher efficiency and lower costs. The central receiver system uses a field of tracking mirrors (two-axis) to focus sunlight at a central point atop a receiver tower. Working fluid contained in the receiver boiler is heated to a temperature of around 1,000°F and then pumped into a turbogenerator unit in a plant beside the tower. Incorporating a thermal storage unit would permit fairly constant power output from a few hours after sunrise until shortly after sunset.

Construction has begun on a 10-MW (electric) central receiver pilot plant in Barstow, California, funded primarily by DOE and projected to cost about $123 million, or about $12,300/kW (this would correspond to a power cost of around 50¢/kW). Arizona Public Service Company, in conjunction with DOE, is planning a 60-MW central receiver solar thermal power system on Unit 1 (115 MW) of its oil-fired Saguaro Powerplant, 75 miles southeast of Phoenix. Completion is currently targeted for 1985.

The available solar radiation resource in the United States was discussed above. Because they involve the use of a field of tracking mirrors to concentrate solar radiation on a boiler, solar thermal electric plants utilize only direct solar radiation. Table B-7 shows typical capacity factors for tracking systems using direct radiation that would apply to systems with no storage; higher capacity factors can be obtained by lowering the rated capacity and incorporating thermal storage (i.e., storing some excess energy in the middle of the day to use later to generate power). Because of the much higher levels of direct solar radiation available there, deployment of solar thermal energy plants will be limited at least initially to the Southwest.

Table B-10 shows estimates of potential future (mature) costs for a 100-MW, commercial-size, central receiver solar thermal electric plant located in the southwestern United States (49). The average of the base capital cost estimates is about $1,525/kW in 1976 dollars. (Estimated costs for a 100-MW distributed collector plant are about 50 to 70 percent higher.) Figure B-11 shows estimates by

TABLE B-10

Potential Future Capital Costs for a 100 MW Central Receiver Plant [a]

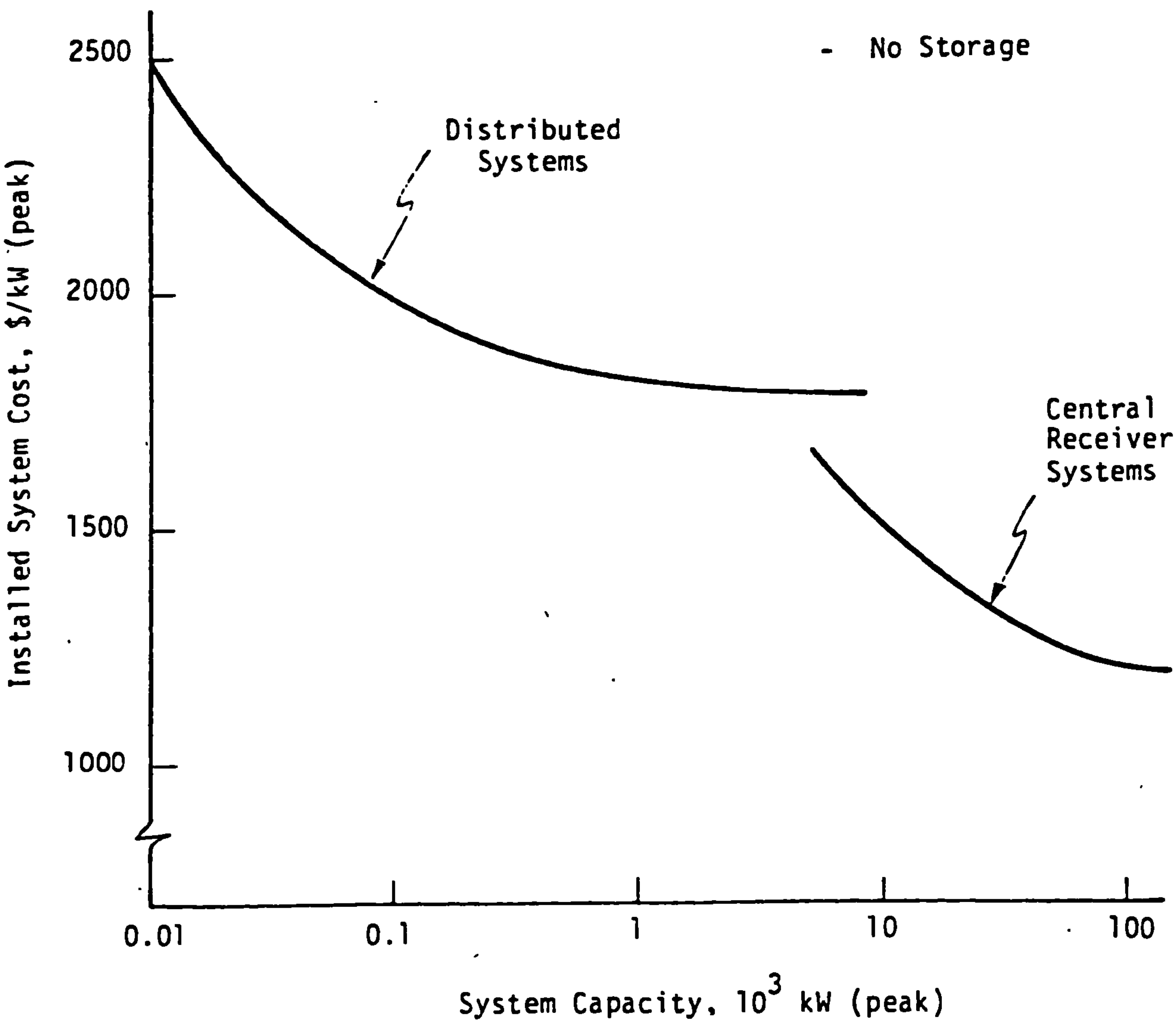
<table>
<tr><th>Contractor</th><th>Martin</th><th>McDonnell</th><th>Honeywell[b]</th><th>JPL</th><th>Metrik</th></tr>
<tr><td>Type Plant</td><td>Cycling</td><td>Cycling</td><td>Cycling</td><td>Cycling</td><td>Cycling</td></tr>
<tr><td>Region</td><td>Southwest</td><td>Southwest</td><td>Southwest</td><td>Southwest</td><td>Southwest</td></tr>
<tr><td>Modules:</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Collector</td><td>759</td><td>585</td><td>582</td><td>935</td><td>675</td></tr>
<tr><td>Receiver</td><td>182</td><td>53</td><td rowspan="2">93</td><td rowspan="2">230</td><td>62</td></tr>
<tr><td>Tower</td><td>180</td><td>71</td><td>136</td></tr>
<tr><td>Storage (420 mWh)</td><td>305</td><td>100</td><td>416</td><td>122</td><td>239</td></tr>
<tr><td>Cooling Water</td><td>61</td><td>46</td><td>60</td><td rowspan="3">250</td><td>60</td></tr>
<tr><td>Turbogenerator</td><td>83</td><td>87</td><td>128</td><td>130</td></tr>
<tr><td>Control</td><td></td><td>5</td><td></td><td>5</td></tr>
<tr><td>Electric Plant</td><td>115</td><td>21</td><td>305</td><td rowspan="2">386</td><td rowspan="2">125</td></tr>
<tr><td>Balance of Plant</td><td></td><td>91</td><td></td></tr>
<tr><td>Backup</td><td>--</td><td>--</td><td>--</td><td>--</td><td>--</td></tr>
<tr><td>TOTAL</td><td>1,685</td><td>1,059</td><td>1,584</td><td>1,923</td><td>1,432</td></tr>
<tr><td>Indicated Capacity Factor</td><td>0.570</td><td>0.443</td><td>0.459</td><td>0.540</td><td>0.500</td></tr>
<tr><td>Indicated Availability (%)</td><td>90</td><td>90</td><td>90</td><td>90</td><td>90</td></tr>
<tr><td>Land Use (mi^2)</td><td>2.4</td><td>1.2</td><td>1.4</td><td>1.3</td><td>1.2</td></tr>
<tr><td>Collector Area (mi^2)</td><td>0.334</td><td>0.348</td><td>0.364</td><td>0.39</td><td>0.267</td></tr>
<tr><td>Date of Estimate</td><td>1/76</td><td>12/75</td><td>1/76</td><td>3/76</td><td>8/76</td></tr>
</table>

[a] All Costs in 1976 $/kW (Rated)

[b] Normalized for dry cooling tower

Source: Reference (49).

Figure B-11 Cost of Solar Thermal Power Generating System (1978 Base Cost Dollars)



Source: Reference (50).

Arthur D. Little, Inc. (50), of potential base capital costs for solar thermal plants with no storage. EPRI estimates a complete capital cost of about $2,400 to $2,900/kW (in late-1977 dollars) for a 100-MW, central receiver plant with 6-hour thermal storage and a capacity factor of 46 percent in the Southwest (51). A 50-MW hybrid solar thermal plant incorporating a conventional combustion turbine but no storage (2,500 hours/year operation on solar energy, the rest from oil or gas) is estimated by EPRI to have a complete capital cost of $1,400 to $1,700/kW. First commercial service for both systems is estimated to be 1997. These costs have not yet been demonstrated and are still high compared to other sources of intermediate-load power generation.

B.13 WIND ENERGY

The DOE/NASA wind program centers on development and demonstration of a wide range of wind turbine designs (52); current field demonstrations include:

- Mod O, a 100-kW prototype in operation at NASA's Plum Brook Station in Sandusky, Ohio.

  Mod OA, a slightly redesigned version of the Mod O, with a blade diameter of 125 feet and rated output of 200 kW. Four of these are currently in operation.

  Mod 1, a 210-foot diameter turbine with a rated output of 2,000 kW in winds of around 33 mph; the first was constructed at Boone, North Carolina.

  Mod 2, a 300-foot diameter turbine with a rated output of 2,500 kW in winds of about 28 mph (at hub height). Three of these machines are to be in operation at a site in the Goodnoe Hills in Washington by mid-1981.

In addition, a number of manufacturers have constructed wind units for utility demonstration:

- WTG Energy Systems has constructed a prototype of its 80-foot diameter, 200-kW machine (28 to 30 mph winds) on Cuttyhunk Island, Maine, and recently sold a second machine to Nova Scotia.
- Dominion Aluminum Fabricating built a prototype, 80-by-120-foot vertical-axis Darrieus machine rated at 200 kW (30 mph winds) for the National Research Council of Canada's program. Alcoa is offering

substantially the same design with a 500-kW rating (40 mph winds), the first of which is to be operated shortly by Southern California Edison.

- Wind Power Products/Bendix has sold a prototype of its 165-foot diameter, 3,000-kW (40 to 45 mph winds) turbine to Southern California Edison; it will be operational in the near future.

- Hamilton Standard is manufacturing a 255-foot diameter machine rated at 3,000 or 4,000 kW (the latter in 35 mph winds). One of these will be installed for a Department of the Interior/Water and Power Resources Service project at Medicine Bow, Wyoming.

The output potential of a wind turbine is proportional to the cube of the wind speed. A wind turbine is designed to start generating power at a "cut-in" wind speed--generally about 8 to 14 mph. Power output increases with wind speed up to a maximum or rated wind speed that is typically between 20 and 40 mph. A turbine with a rated wind speed of 30 mph would have a rated power output about twice as high as a turbine having the same blade diameter but a rated wind speed of 24 mph. The capacity factor depends upon the average wind speed at a given site and the variation about the average, and upon the rated wind speed (17, 53, 54).

In general terms, utility wind turbines will probably be planned to operate at capacity factors in the range of 20 to 45 percent, depending on the wind characteristics of specific sites and design choices as to rated wind speeds. Because of the sensitivity of turbine output to available wind speeds, it is likely that commercial deployment will be limited (at least initially) to sites with average annual wind speeds of 15 mph and over (55).

Justus (56) has estimated that a large array of 1,500-kW turbines (29.3 mph rated wind speed at hub height) spread across the central United States (Nebraska, Kansas, Missouri, Oklahoma, and Texas) could provide at least a 100-kW output per unit on the average about 81 percent of the time. This corresponds to an effective capacity displacement of roughly 100/1500, or 6.7 percent. The effective capacity displacement was higher for units with lower rated wind speed (e.g., same blade diameter but smaller generator rating), but lower for a smaller New England array and near zero for single units.

A study by General Electric Company for EPRI (69) estimated the capacity displacement of essentially the same turbine design (but with a rated wind speed of 23 to 26 mph) in three utility areas: Niagara Mohawk Power Corporation (northern

New York); Kansas Gas & Electric Company (KG&E); and the West Group of the Northwest Power Pool (NWPP). The projected capacity factors for all the sites were fairly similar--in the neighborhood of 40 percent. However, at a 5-percent penetration level of wind turbines into the system (representing between approximately 110 turbines for KG&E to approximately 2,310 for the NWPP), the estimated effective capability ranged from 5 to 45 percent of rated capacity.

The wind energy resources of the United States have been characterized quite well in terms of their general geographic distribution. Figures B-12 and B-13 show two estimates of the distribution of available wind energy across the country (54). Also, a more detailed wind energy resource atlas has recently been published (57).

For wind turbines with a rated wind speed of about 30 mph, the installed costs of machines currently ordered or under construction is around $2,000/kW or greater. For example:

- The installed cost of the first three DOE/NASA Mod 2 machines is estimated at about $1,840/kW (58)
- The National Research Council of Canada's first 200-kW vertical-axis machine cost about $293,000 or $1,465/kW, FOB factory, plus about the same again for installation and testing (a similar additional sum was recently required to replace the rotor after it collapsed) (59).

Lower specific dollars-per-kilowatt costs have been quoted for machines with higher rated wind speeds, but they are nevertheless roughly equivalent in terms of actual energy costs (since they would operate at lower capacity factors in equal wind conditions). For example, the Hamilton Standard unit to be installed at Medicine Bow is estimated to cost $1,500/kW, but its rated wind speed is about 35 mph (60).

Capital costs are expected to be lower in the future if current designs are brought into mass production. For example:

- General Electric estimates an installed base capital cost of $590/kW in 1976 dollars for the 100th unit of its 1,500-kW design (61)
- Boeing estimates an installed cost of about $800/kW for the Mod 2 machine in mass production (58)

Figure B-12 Mean Annual Wind Power Density (W/m^2)

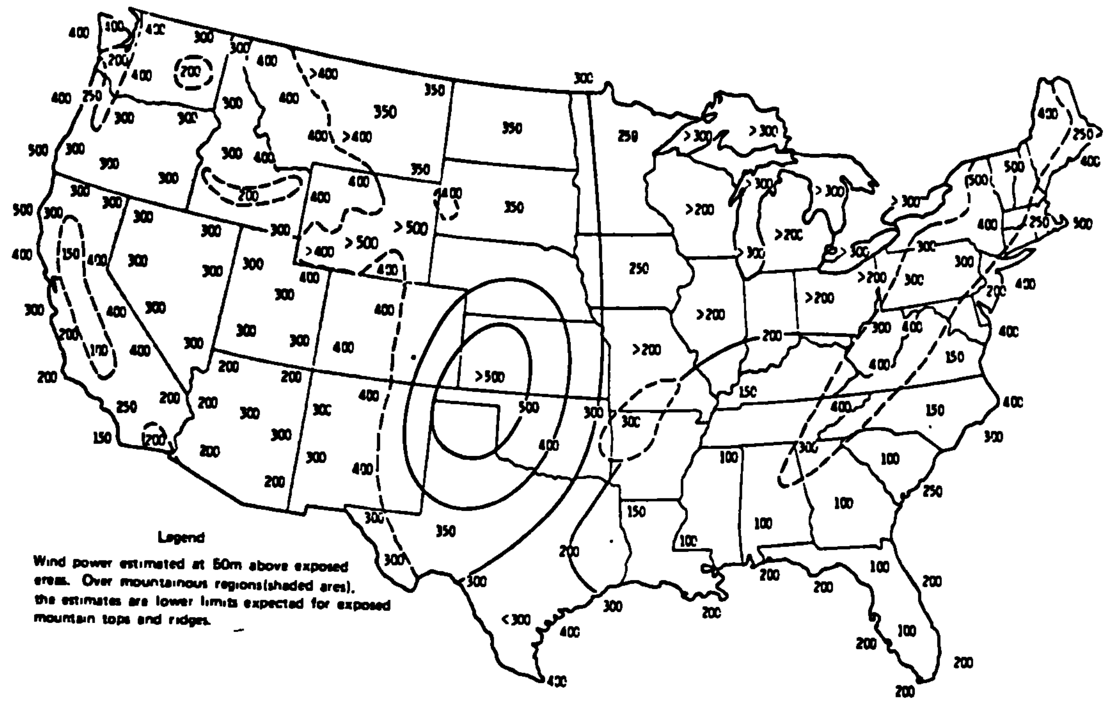
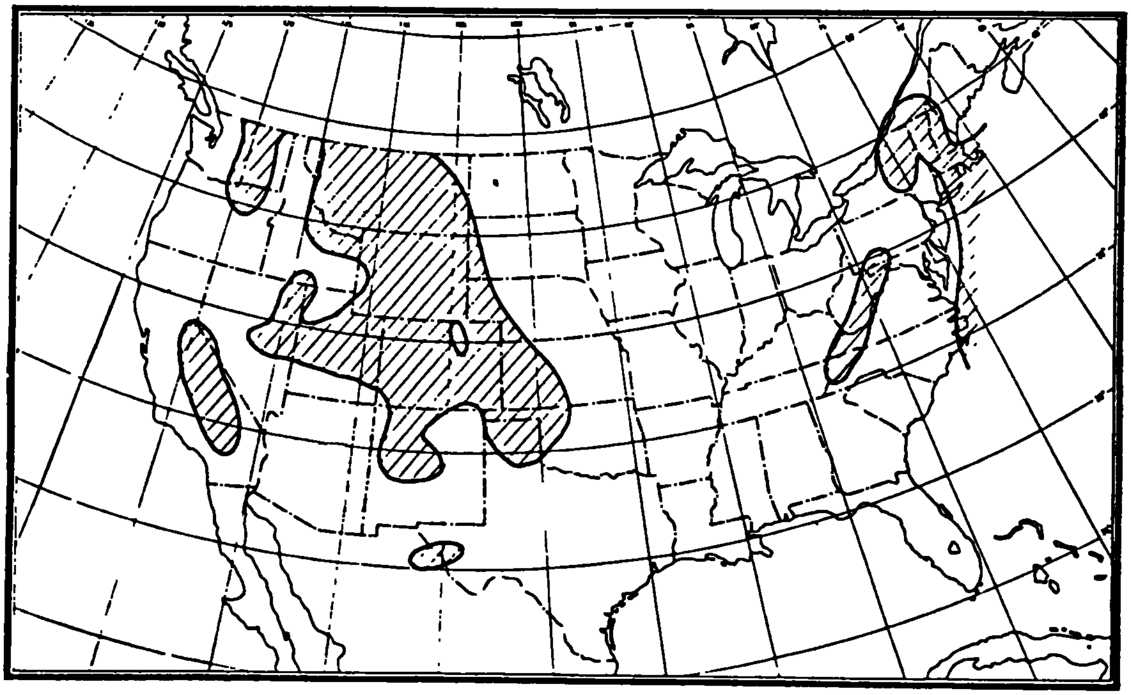


Figure B-13 Areas in the U.S. Where Annual Average Wind Speeds Exceed 18 mph at 150 ft. Above Groundlevel



Source: Reference (54).

- Mass production estimates for the 200-kW Canadian NRC/DAL vertical-axis and WTG Energy Systems, Inc., horizontal-axis machines fall in a similar range of about $800 to $1,200/kW installed (17).

Lower costs eventually may be possible with advanced designs and/or larger production runs.

B.14 TIDAL POWER

The only large tidal plant constructed to date is the 240-MW Rance Station located in the Rance estuary upstream of St. Malo, France. It is a single-pool, double-effect development that includes direct and reverse pumping to maximize the energy output. The mean tide range there is 28 feet, with a maximum of 44.5 and a minimum of 11.5 feet. The Rance Station can operate in four different modes, including single- and double-effect operation with or without pumping (depending on the tide) to maximize power output. Even with the flexibility obtained by the various methods of operation, the plant is still not able to provide and adequate amount of power consistently during peak-demand hours. There is also a large difference between the power output during spring tides (122.5 MW on the average) and that during the neap tides (30.8 MW). Without using the sophisticated operating modes named above, including pumping, the mean annual output at the Rance Station would be 45 MW. However, by using the various modes of operational pumping described, an average output of 65 MW is obtained. The Rance Project was begun in 1959 and completed in 1967 at a final cost of 570 million francs (about $100 million).

The only potentially developable tidal power sites in the United States are the Passamaquoddy Bay Region (including Cobscook Bay) in Maine and the Cook Inlet Region (near Anchorage) in Alaska. The mean tides are 18.2 and 25.1 feet, respectively. Potential tidal power projects in these regions were identified by Stone and Webster for the Energy Research and Development Administration (ERDA) (62), and the economic analyses for 7 of the 11 possible projects are summarized in Table B-11. The estimated construction costs in 1976 dollars for the Alaska projects range from $1.5 billion for the Knik Arm project (750 MW, 0.44 annual capacity factor) to $6 billion for the combined Turnagain Arm and Knik Arm projects (2,600 MW, 0.48 annual capacity factor). The estimated construction costs for the Maine projects range from $362 million for the Cooper Island project in Cobscook Bay (180 MW, 0.37 annual capacity factor) to $2 billion for a joint U.S.-

TABLE B-11

Estimated Capital Costs of Potential Tidal Power Projects
(1976 Dollars)

	State of Alaska		
	Knik Arm	Turnagain Arm	K. and T. Arms
Total Installed Capacity, MW	750	2,600	2,600
Total Dependable Capacity, MW	None	None	960
Annual Capacity Factor	0.44	0.40	0.48
Total Construction Period, Years	7	8	10
Construction Cost (million $)	1,572	4,657	6,070
Total Investment (million $)	1,957	5,960	8,195

	State of Maine			
	Int'l (1)	Int'l (2)	Treat Island	Cooper Island
Total Installed Capacity, MW	500	1,000	180	180
Total Dependable Capacity, MW	500	500	None	None
Annual Capacity Factor	0.44	0.24	0.43	0.37
Total Construction Period, Years	7.5	7.5	4	4
Construction Cost (million $)	1,400	2,174	407	362
Total Investment (million $)	1,790	2,888	492	441

Source: Reference (62).

Canadian Passamaquoddy Bay project (1,000 MW, 0.27 annual capacity factor). The total combined developable power in these two regions is on the order of 4,500 MW with an annual output of 18.3 billion kWh.

B.15 WOOD AND OTHER BIOMASS

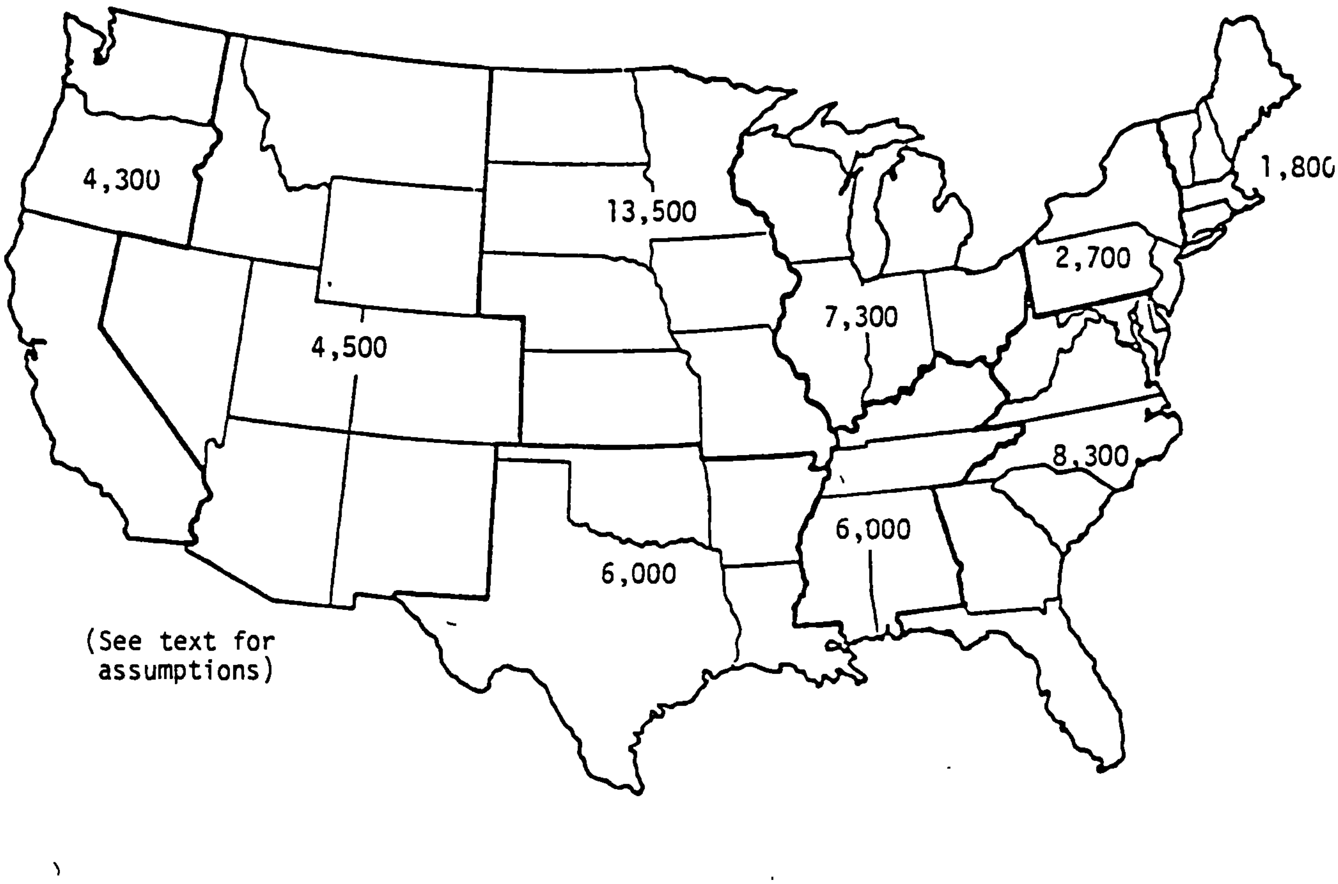
The biomass resource potential in the United States, other than from biomass farms, is equivalent to about 54,000 MW (assuming a typical heat rate of about 14,500 Btu/kWh (63) and a capacity factor of 100 percent). Figure B-14 shows the geographic distribution of this potential. The realizable biomass-fueled electrical capacity would be substantially lower--probably less than half of this. Some of the potential would be economically infeasible to collect, and some is on private and publicly-owned land that would not be available for collection. Furthermore, there will be competing demands on biomass as a fuel, such as for industrial boilers, residential stoves, and gasohol.

For the near term, the most likely technology for the production of electricity from biomass will be the direct combustion of wood chips and wood and agricultural wastes in a steam boiler. There are several types of wood-fired boilers presently in use, and there appear to be no major technical problems in using the direct combustion of wood for the production of electricity. The present outlook for biomass-fired capacity in the United States is on the order of several hundred megawatts. Although units currently planned are being considered for base-load applications, wood-fired plants could be run on an intermediate-load basis as well. Biomass or wood must be used close to where it is grown or harvested because hauling it more than around 20 or 30 miles is expensive. Most bio-energy plants will probably be in the range of 10 to 50 MW (64).

The Pacific Gas and Electric Company has recently scheduled a $100 million, 50-MW biomass-fueled powerplant to start in 1982. The proposed facility is to be fueled with dense pellets of agricultural wastes (such as grape clippings, sawdust, and cotton waste). The plant will also use its steam generator to raise steam for drying the pelletized fuel. The Burlington, Vermont, Electric Department is currently operating two 7-MW wood-fired plants and is planning the construction of a 50-MW (46-MW net) wood-burning powerplant.

For the direct combustion of green wood chips, MITRE estimates a base capital cost of $945/kW in 1975 dollars for a 45-MW plant (65). For the proposed 50-MW Burlington, Vermont, plant, a preliminary study by Henningson, Durham,

Figure B-14 Estimated Potential of Selected Biomass Fuels in Megawatts by U.S. Census Regions (Not including Biomass Farms)



and Richardson estimated a base capital cost of $41,278,000, which is $826 per gross kilowatt or $897 per net kilowatt, in 1977 dollars (63). A more recent estimate suggests this may be low by 10 to 15 percent. Rocket Research (66) estimates a base cost of $900/kW gross or $1,000/kW net for a 25-MW plant. Overall, base capital cost is about $1,000 to $1,200/kW in 1979 dollars for a 50-MW plant. Total capital investment would be roughly 30 percent higher.

Estimates of plant heat rate vary from 13,000 to 18,000 Btu/kWh; a value of 14,500 Btu/kWh net is typical. Estimates of operation and maintenance costs range from 0.48¢/kWh (Burlington, 1977 dollars) to 1.19¢/kWh (MITRE, 1976 dollars).

MITRE Corporation estimates the cost of harvesting green wood chips at $12 to $15 per ton, and trucking costs at $1.75 per ton for loads up to 20 tons and distances up to 20 miles (1976 dollars). Henningson, Durham, and Richardson (63) estimate the cost of wood chips delivered to Burlington at $12 per ton (1977 dollars), although this is low compared to the average 1979 cost of about $15 per ton at the Burlington Electric Department's 7-MW Moran units. Overall, the cost of green wood chips delivered up to 20 miles is about $14 to $18 per ton in 1979 dollars. The average heating value of green wood chips is about 9 million Btu per ton.

Table B-12 gives the component costs and total bus-bar power costs for a 50-MW, base-loaded, wood-burning powerplant in New England, assuming a fixed charge rate of 12 percent and a capacity factor of 70 percent (67). The estimated power cost is high compared to that for conventional base-load central generating stations.

B.16 ASSESSMENT OF CATEGORY C SUPPLY ALTERNATIVES

Geothermal energy resources in the United States are large, though limited primarily to the West and the Gulf Coasts. Estimates of U.S. installed capacity possible by the year 2000 range from 2,000 MW to 60,000 MW and higher (68, 69). These resources include: dry steam (currently in use); hydrothermal; geopressured; dry hot rock; and magma. Generation of electricity from geothermal energy is presently limited to the Geysers region of California where installed capacity is about 665 MW and a further 583 MW is under construction or currently planned. Geothermal powerplants are best suited to base-load operation, though limited load-following (within 15 percent) appears practical (70). At Pacific Gas &

TABLE B-12

Estimated Costs for a Wood-Burning Powerplant in New England
(1979 Dollars)

Plant Capacity, MW	50
Base Capital Cost, \$/kW	1000 - 1200
Heat Rate, Btu/kWh	14500
Capacity Factor, %	70
Wood Cost Delivered, \$/ton	14.00 - 18.00
Wood Heat Content, MBtu/ton	9.5
Power Cost, ¢/kWh	
Capital	1.96 - 2.35
Fuel	2.14 - 2.75
O&M	0.50 - 1.25
TOTAL	4.60 - 6.35

Source: Reference (48).

Electric Company's Geysers units, steam is vented to prevent blockage of wells and loss of steam flow when generating units are off-line.

Solid waste-fired power generation using waterwall incinerators or similar mass-fired boiler technology is currently practical (71), and several such plants are in operation, although the resource is a limited one. Given a typical generation rate for municipal solid waste (MSW) of 4 pounds/person/day and an energy production of 500 kWh per ton, the national potential is theoretically on the order of 10,000 MW at current population levels. In practice, the realizable capacity potential is substantially less for two reasons. First, the fraction that can feasibly be collected for use in plants with a typical capacity of 1,000 to 1,500 tons per day (about 20 to 30 MW) is significantly lower. Second, not all the readily collectible MSW will be used for new electric power generation; some will be used for industrial steam production only, and some will be converted to refuse-derived fuel (RDF) for co-firing in existing facilities (see Category B technologies). It is expected that MSW-fired powerplants will be developed primarily by state and local government authorities and/or private companies, and the output sold to utility companies at a price related to the utilities' marginal costs. For several reasons, including the relatively high capital investment and the desire for continuous waste throughout, MSW mass-fired powerplants will be designed predominantly for base-load operation.

Advanced nuclear converter reactors and breeder reactors, which can make much more efficient use of uranium resources, are being developed in a number of countries. Currently, the French program is the most advanced, with its first commercial-size (1,200 MW) sodium-cooled breeder under construction at Creys-Malville. To the extent that breeder reactors or advanced converter reactors are deployed in the United States before the turn of the century, they will be used for base-load power generation.

It is quite possible that solvent-refined coal in solid (SRC-I) or liquid (SRC-II) form will be used in new commercial generating plants before the year 2000. Because the capital cost is relatively high and the fuel more expensive than conventional coal, new SRC-fired powerplants are most likely to be used for base-load generation. It has been estimated (34, 44) that the capital cost of a new powerplant fired with SRC-I would be about 20 percent less than that of a conventional coal plant with flue gas desulfurization (FGD); most of this difference results from elimination of the need for the FGD unit.

Molten carbonate fuel cells operate on principles similar to phosphoric acid fuel cells (see Category A technologies). However, their higher operating temperatures offer the potential for higher conversion efficiencies. Current research is aimed toward developing molten carbonate fuel cells and advanced coal gasification technology into an integrated plant for clean base-load power generation from coal with good efficiency. However, both components--cell and advanced gasifier--require a significant amount of additional research and development, and commercial units are not expected before the mid- to late-1990's (42, 72).

Ocean thermal energy conversion (OTEC) involves the generation of power using the temperature difference of 35°F and over between warm surface waters and colder deep waters available in tropical oceans. Potential sites of principal interest are near Hawaii and Puerto Rico and parts of the Gulf of Mexico, although the south coast of California and the east coast of Florida have been discussed. An experimental 50 kW "mini-OTEC" is currently in operation off Hawaii. DOE-sponsored programs, scheduled to begin pilot facility operation in the near future and module testing around 1983, are projected to lead to first commercial operations in the 1990's (70, 73). Because of the continuous availability of the thermal gradient heat source (in practical locations) and the relatively high capital investment, OTEC plants will be designed for base-load power generation.

Fusion involves the production of energy from the fusing of light atoms at ultra-high temperatures. The primary fuels would be two isotopes of hydrogen: deuterium, which can be extracted from water, and tritium, which can be bred from lithium. Fusion power research is closing in on achieving "break-even," defined as the situation where the energy released by a fusion device just equals the energy required to run it. Once this basic feasibility stage has been achieved, significant scientific and engineering development will be required. Current DOE plans call for a demonstration fusion reactor by about 2000, though estimates of first commercial operation extend to around 2015 (70, 74).

Magnetohydrodynamics (MHD), organic bottoming cycles, and thermionic conversion are technologies designed to improve the efficiency of thermal electric powerplants. None are likely to see significant deployment for utility power generation before the year 2000. Active MHD research and development programs have been under way for some time in this country and in the USSR. However, first commercial operation of coal-fired MHD powerplants, which are designed for base-load operation, is generally estimated to be after the year 2000 (44, 42).

Several advanced solar-derived energy sources are also unlikely to be in commercial operation before 2000. These include the microwave solar satellite system and energy from ocean waves and currents. Wave energy was an important and promising technology in the U.K. research program (75) but recently suffered a serious setback when a detailed engineering study found that previous cost estimates were about 10 times too low (76).

In addition to the storage technologies discussed in detail under Category A, a number of other advanced concepts are being explored. These include capacitors, flywheels, superconducting magnets, and hydrogen and thermochemical pipelines. However, none of these are expected to see commercial deployment for electric utility use before the year 2000 (7).

REFERENCES

1. Conceptual Design of Thermal Energy Storage Systems for Near-Term Electric Utility Applications, Volumes 1 & 2, EPRI EM-103/Project 1082-1, Electric Power Research Institute prepared by General Electric Company, Schenectady, N.Y. (April 1979).

2. Conceptual Design of Thermal Energy Storage Systems for Near-Term Electric Utility Applications, EPRI EM-1218 Project 1082-1 Final Report, Electric Power Research Institute prepared by General Electric Company, Schenectady, N.Y. (November 1979).

3. Arizona Public Service Repowering Project: System Concept, Arizona Public Service Company, Phoenix, and Martin Marietta Corporation, Denver, Colorado (September 1979).

4. F.R. Kalhammer, "Energy-Storage Systems," Scientific American, Vol. 241 (December 1979).

5. Conceptual Design for a Pilot/Demonstration Compressed Air Storage Facility Employing a Solution-Mined Salt Cavern, EPRI EM-391, prepared by General Electric Company for the Electric Power Research Institute, Palo Alto, California (June 1977).

6. Technical and Economic Assessment of Advanced Compressed Air Storage (ACAS) Concepts, EM-1289, prepared by Central Electricity Generating Board, Southampton, England for the Electric Power Research Institute, Palo Alto, California (December 1979).

7. "Putting Baseload to Work on the Night Shift," EPRI Journal, 5, 3 (April 1980).

8. Interim Cost Estimates for Advanced Battery Systems, EPRI EM-742, prepared by Arthur D. Little, Inc. for the Electric Power Research Institute, Palo Alto, California (July 1978).

9. Design and Cost Study for State-of-the-Act Lead Acid Load Leveling and Peaking Batteries, EPRI-EM-375, prepared by ESB, Inc. for the Electric Power Research Institute, Palo Alto, California (February 1977).

10. "Comparative Evaluation of New Electric Generating Technologies," Energy Technology VII, Government Institutes, Inc. (April 1979).

11. The Energy Daily, 7, 151 (August 8, 1979).

12. The President's Commission on Coal, Coal Data Book, U.S. Government Printing Office, Washington, D.C. (February 1980).

13. International Coal Technology Summary Document, DOE/PE-0010, U.S. Department of Energy, Washington, D.C. (June 1979).

14. R.D. Hersey, Jr., "Gasification Plant Rising Amid Many Snags," New York Times (November 17, 1980).

15. I.M. Berman and P.S. Schmidt, "Fuel Cells and Coal-Derived Fuel," Power Engineering, Vol. 84 (October 1980).

16. "Utilities Finally Put Big Money on the Fuel Cell," Business Week, No. 2633 (April 21, 1980).

17. Assessment of Alternate Technologies for Utility Baseload Generating Capacity in New England, Energy Research Group, Inc. for New England Power Company, Westborough, Massachusetts (January 1979).

18. P. Bolan and L.M. Handley, "First Generation Fuel Cell Power Plant Characteristics," Power Systems Division, United Technologies Corporation, Hartford, Connecticut (undated).

19. The Target Capital Costs for the Implementation of Fuel Cells and Electric Storage Devices Within the National Energy System, BNL-20523, Brookhaven National Laboratory (September 1975).

20. Economic Assessment of the Utilization of Fuel Cells in Electric Systems, EPRI EM-366, Public Service Electric and Gas Company in New Jersey for the Electric Power Research Institute, Palo Alto, California (November 1976).

21. Estimates of National Hydroelectric Power Potential at Existing Dams, U.S. Army Corps of Engineers, Institute for Water Resources (July 1977).

22. Preliminary Inventory of Hydropower Resources (six volumes), National Hydroelectric Power Resources Study, U.S. Army Corps of Engineers, Institute for Water Resources and the Hydrologic Engineering Center (July 1979).

23. A.W. Eipper, "Possible Impacts of Hydroelectric Developments on Fish and Wildlife," Waterpower '79, Abstracts of International Conference on Small-Scale Hydropower, October 1-3, 1979, U.S. Government Printing Office.

24. Hydropower--An Energy Source Whose Time Has Come Again, EMD-80-30, U.S. Government Printing Office (January 11, 1980).

25. A Report on New England Hydroelectric Development Potential, New England Federal Regional Council, Boston, Massachusetts (June 1976).

26. E. O'Brien, Evaluation of Hydroelectric Potential in the Northeast, Tibbets-Abbett-McCarthy-Stratton, New York, New York (April 1978).

27. Dickinson, W.C., "Annual Available Radiation for Fixed and Tracking Collectors," Solar Energy, 21, 3 (1978).

28. Requirements Assessment of Photovoltaic Power Plants in Electric Utility Systems, EPRI ER-685, General Electric Company for the Electric Power Research Institute, Palo Alto, California (June 1978).

29. Ferber, R.P., and Forney, R.G., "The DOE Photovoltaics Program," by the Jet Propulsion Laboratory, California Institute of Technology for the U.S. Department of Energy (May 15, 1980).

30. Principal Conclusions of the American Physical Society Study Group on Solar Photovoltaic Energy Conversion, The American Physical Society, New York, N.Y. (January 1979).

31. M.L. McKinney, Regional Conversion to Coal, U.S. Department of Energy, EF-77-C-01-2468, prepared by Engineering Societies Commission on Energy, Washington, D.C. (March 1980).

32. J. Weslowski, "New Ways to Use Coal Probed," Electric Light and Power, Vol. 58 (February 1980).

33. Gordon Associates, Overcoming Institutional Barriers to Solid Waste Utilization as an Energy Source, Final Report, Division of Synthetic Fuels, U.S. Department of Energy, Washington, D.C. (November 1977).

34. Preliminary Capital Cost Estimates of SRC-Fired Power Plants, EPRI AF-1011, Electric Power Research Institute prepared by Bechtel National, Inc., San Francisco, CA (February 1979).

35. K. Maize, "Cost of SRC Project Rises to Over a Billion Dollars Each," The Energy Daily (January 23, 1980).

36. R. Myers, "EPRI Puts $50 Million Into Gasification Project," The Energy Daily (February 13, 1980).

37. "GE Will Put $25 Million Into Coal Gasification Combined Cycle Project," The Energy Daily (October 15, 1980).

38. P.J. Margaritis and R.M. Strausky, "Westinghouse to Launch Coal-Gasifier with Combined Cycle Unit," Energy International, Vol. 17 (March 1980).

39. "Advanced Gas Turbine Not Needed for Coal Gas/Combined Cycle: EPRI," Electric Light and Power, Vol. 57 (May 1979).

40. "Cogeneration," Power Engineering, 82, 3, pp. 34-42 (March 1978).

41. "Georgetown Univ. Fluidized-Bed Boiler Operates Successfully," Electric Light and Power, Vol. 58 (May 1980).

42. Lewis Research Center, Evaluation of Phase 2 Conceptual Designs and Implementation Assessment Resulting from the Energy Conversion Alternatives Study (ECAS), NASA-TM-X-73515, National Aeronautics and Space Administration, Lewis Research Center, Cleveland, Ohio (April 1977).

43. Utility Boiler Design/Cost Comparison: Fluidized-Bed Combustion Versus Flue Gas Desulfurization, PRS-23, Tennessee Valley Authority, EPA-600/7-77-126, U.S. Environmental Protection Agency (November 1977).

44. Technical Assessment Guide, EPRI PS-1201-SR, Electric Power Research Institute, Palo Alto, California (July 1979).

45. Cogeneration: Its Benefits to New England, Final Report of the Governor's Commission on Cogeneration, Massachusetts Energy Office, Boston, Massachusetts (October 1978).

46. The Potential for Cogeneration Development in Six Major Industries by 1985, Resource Planning Associates, Cambridge, Massachusetts (December 1977).

47. Commercialization Task Force Report for Cogeneration, National Association of Manufacturers, Washington, D.C. (August 1978).

48. The Energy Daily, 8, 33 (February 20, 1980).

49. Solar Program Assessment: Environmental Factors, Solar Thermal Electric, ERDA 77-4774 (March 1977).

50. The Potential for Solar Energy Utilization in Southern New England, Arthur D. Little, Inc., Cambridge, Massachusetts (1979).

51. Technical Assessment Guide, EPRI PS-866-SR, Electric Power Research Institute, Palo Alto, California (June 1978).

52. Federal Wind Energy Program, DOE/ET-0023/1, U.S. Department of Energy, Washington, D.C. (January 1978).

53. F.R. Eldridge, Wind Machines, NSF-RA-N-75-051, The MITRE Corporation for the National Science Foundation, Washington, D.C. (October 1975).

54. F.R. Eldridge, Wind Machines, Second Edition, The MITRE Energy Resources and Environment Series, Van Nostrand Reinhold Company, New York (1980).

55. Wind Energy Mission Analysis, COO/2578-1/2, General Electric Company for the U.S. Energy Research and Development Administration, Washington, D.C. (February 1977).

56. C.G. Justus, "Wind Energy Statistics for Large Arrays of Wind Turbines (New England and Central U.S. Region)," Solar Energy, 20, 5, pp. 379-386 (May 1978).

57. Wind Energy Resource Atlas, PNL-3195, Geomet Technologies, Inc., for Battelle Pacific Northwest Laboratories, Richland, Washington (1980).

58. Energy Insider, 2, 24, U.S. Department of Energy, Washington, D.C. (November 1979).

59. Personal communication with J.R. Templin, National Research Council, Ottawa (February 1980).

60. News Release, Water and Power Resources Service, U.S. Department of the Interior (February 4, 1980).

61. Requirements Assessment of Wind Power Plants in Electric Utility Systems, EPRI ER-978, General Electric Company for the Electric Power Research Institute, Palo Alto, California (January 1979).

62. Final Report on Tidal Power Study for the U.S. Energy Research and Development Administration, Report No. DGE/2293-3, Stone & Webster Engineering Corporation, Boston, Massachusetts (March 1977).

63. Burlington, Vermont, Refuse-Wood Power Plant, Aquaculture, Greenhouse: A Conceptual Study, Henningson, Durham and Richardson, Inc., Washington, D.C. (December 30, 1977).

64. P.F. Bente, Jr., "An Overview of Bio-Energy Projects in the United States," Solar Energy, Vol. 25, No. 5 (1980).

65. System Descriptions and Engineering Costs for Solar-Related Technologies, Vol. IX, Biomass Fuels Production and Conversion Systems, MTR-7485, The MITRE Corporation, METREK Division (June 1977).

66. Prefeasibility Study for 5 Megawatt, 10 Megawatt and 25 Megawatt Waste-wood Burning Electric Power Generating Facilities, Rocket Research Company, Redmond, Washington (November 1978).

67. I.A. Forbes, "Testimony on the Availability of Alternate Energy Sources for the Massachusetts Municipal Wholesale Electric Company," Energy Research Group, Inc., Waltham, Massachusetts (January 1980).

68. P. Kruger, Annual Review of Energy, 1, 159 (1976).

69. Geothermal Resources and Technology in the United States, Report of the Geothermal Resource Group, Supply and Delivery Panel, Committee on Nuclear and Alternative Energy Systems, National Research Council, National Academy of Sciences, Washington, D.C. (1979).

70. EPRI New Energy Resources Department Strategy Paper, EPRI ER-979-SY, Booz, Allen and Hamilton, Inc. for the Electric Power Research Institute, Palo Alto, California (January 1979).

71. Materials and Energy from Municipal Waste, Office of Technology Assessment, Congress of the United States (July 1979).

72. J.M. King, Energy Conversion Alternatives Study (ECAS), Integrated Coal Gasifier/Molten Carbonate Fuel Cell Power Plant Conceptual Design and Implementation Assessment, United Technologies Phase II Final Report, NASA-CR-134955, NASA Lewis Research Center, Cleveland, Ohio (October 1976).

73. Solar Energy: A Status Report, DOE/ET-0062, U.S. Department of Energy, Washington, D.C. (June 1978).

74. J.F. Clarke, "The Next Step in Fusion: What It Is and How It Is Being Taken," Science, 210, 4473, pp. 967-972 (November 28, 1980).

75. Energy from the Ocean, Science Policy Research Division, Congressional Research Service, Library of Congress, Washington, D.C. (April 1, 1978).

76. "U.K. Wavepower Research Yields Little But Disappointment," The Energy Daily, Vol. 8, No. 4 (January 8, 1980).

APPENDIX C

A REGIONAL GENERATION (STACKING) DISPATCH MODEL

CONTENTS

LIST OF TABLES

LIST OF FIGURES

APPENDIX C

A REGIONAL GENERATION (STACKING) DISPATCH MODEL

C.1 INTRODUCTION AND GENERAL METHODOLOGY

Several techniques have been used in the industry to analyze the most economical mix of generation in response to the demand for electricity. The stacking dispatch is one of the most utilized methods in long-range system simulations. The dispatch simulation determines the most appropriate operational and/or economical type of unit needed, given a forecasted change in demand on the system.

The demand on the system is represented by a load duration curve. The curve shows the total hours the demand is likely to exceed a certain level and is obtained by arranging the system's loads (hours) in a decreasing order of magnitude. The abscissae represent units of time and the ordinates are demand or capacity in units of power (megawatts). The area under the curve is the total energy demand for a unit of time (usually a year). The demand on the system is met by the supply of electric energy from the generating units.

The physical operational characteristics of the units (type of generating unit) dictate when and how long these units are turned on in the system; they are classified into the categories of base-load, intermediate, and peaking units. The economic order considers only the cost of the generation from each unit and matches the operational order (although the categorical distinction is not as well defined). Economically, a base-load unit is one whose fuel cost of generation is among the lowest of those making up the whole system. Thus, the base-load unit will be operated as much as possible (near its rated output), and its capacity factor will approach the unit's availability. Economically, the peaking units are those high-priced fuel users that are operated only when the demand load is high. However, these units could be older oil-fired boilers that are considered operationally as intermediate units. The Dames & Moore computer model is an economic dispatch model, although some physical constraints are applied to it.

The units are arranged in ascending order of generating cost in the economic dispatch. The least expensive units are turned on first. The contribution of one unit to the total system generation is represented by the area below the load duration curve (LDC) in Figure C-1, the height of the area is the effective

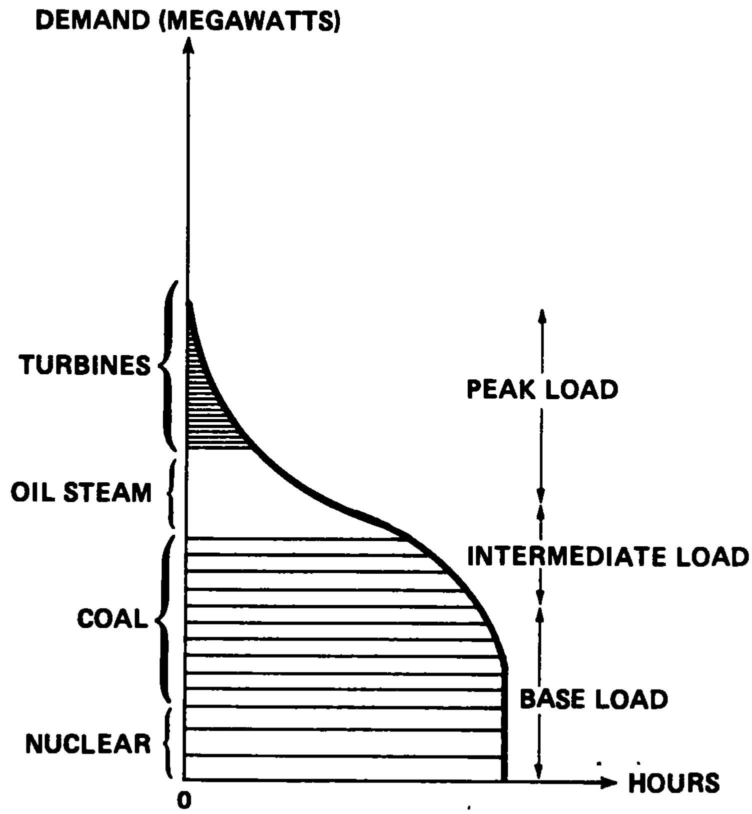


FIGURE C-1
SAMPLE LOAD CURVE

DAMES & MOORE

capacity of the unit, and the abscissa is the length of time the unit is turned on. By changing the load duration curve and the characteristics of the units (new construction, retirements, etc.), the model can simulate the evolution of the system and can be used to determine the best expansion plan to meet future demand growth.

C.2 DAMES & MOORE APPROACH

Dames & Moore's purpose in using a dispatch model is to analyze the supply of electricity for an entire region or a NERC pool. The assumptions behind the analysis are: (1) that the shape of the demand curve remains stable even when the system grows, and (2) the unit dispatching order is known.

The region under study usually is a large aggregate with strongly typed demographic, geographic, and economic characteristics. These characteristics are not likely to shift suddenly; therefore, the first assumption will hold true. The exact dispatch order of every unit is not known. In this model the units are aggregated into fuel types according to the prime mover or method of conversion, i.e., oil-steam (these categories of fuel types will be detailed later). Each category has a definite place under the LDC, and the dispatch order of these fuel types is known. The only assumption needed, then, is the ranking of fuel types rather than the cost of operating the units or the cost of the fuel. The concepts behind the dispatch model are simple, but the detailed implementation is far more complex since a number of features of a real world system must be introduced to make the simulation operable.

C.3 BASIC ELEMENTS

The basic elements of this complex model will be presented in detail, as well as the precise method in which the Dames and Moore Electrical Supply (DAMES) DISPATCH model uses those elements. The mechanisms of the model will be described also.

C.3.1 Supply

The information about the supply of generating capacity is based on an exhaustive list of generating units and their characteristics. The complete list of all existing and future units is used to compute a summary of available capacity by fuel type and by region. (The net dependable capacity is used, rather than the name-plate rating.) Retirements, re-rating, construction of new units, and fuel conversions are taken into account when the capacities are summarized. This computation is done by a separate computer program that allows for several supply scenarios, and the net input or result is a table of capacity by region and fuel type for the next 20 years.

C.3.2 Demand

The information about demand for electric power is represented by a series of load duration curves (LDC's). The LDC is approximated by 11 data points or 10 data segments. The basic or generic LDC is fixed and contained in the model. For each season, year, and region under study, the forecasted peak demand and energy demanded is entered. These data are then used to compute a load factor (the total energy demanded divided by the peak demand for power) for each region by season, which is normalized by the number of hours in the time period. The generic normalized LDC is then adjusted by the load factor. Figure C-2 shows a series of these LDCs and their respective load factors (the model does not allow a load on the system to fall below 10 percent of the peak demand). This mechanism of adjusting the LDC creates a different profile for each season, year, and region under study and therefore represents the variation in peak demand and total demand for energy. The data for demand are generated by the same program that summarizes the capacities per fuel type and region.

C.3.3 Forced Outage

The forced outage rate is the percent of time a unit is out of service for reasons other than scheduled maintenance. In this model the forced outage rates are treated as a reduction of the effective capacity of the units. This approach has been preferred to a more rigorous probabilistic treatment since we are considering a whole region with numerous units and therefore the probability of the outage tends toward the average value. (Reliability of the generation--a prime consideration at the single-system level--is only of secondary importance in the analysis of the whole region.) Stacking dispatch rather than probabilistic dispatch has been chosen because one of the objectives of the model is to evaluate the additional capacities needed in a system. The stacking dispatch method underestimates unserved energy and energy required from peaking units when other units are on forced outage and should, therefore, give a conservative estimate of the additional generating capacity needed. The approximation becomes a good representation of a system as the number of units involved increases.

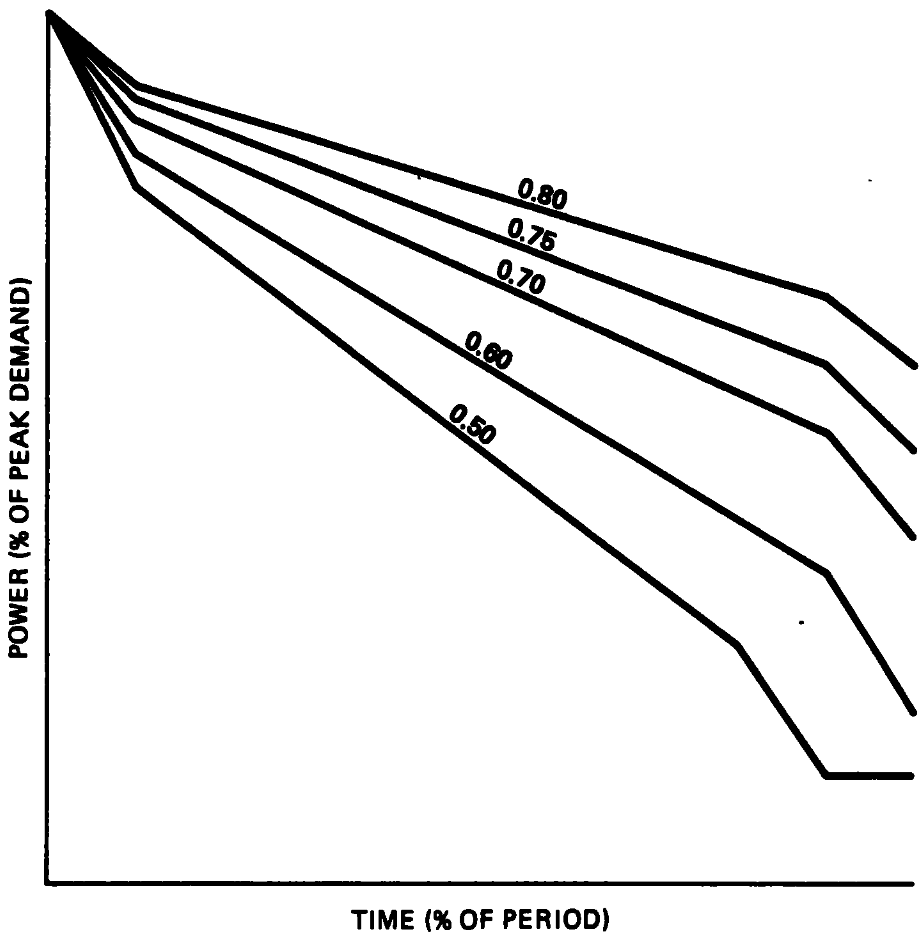


FIGURE C-2

ADJUSTED LOAD DURATION CURVES FOR VARIOUS LOAD FACTORS

C.3.4 Maintenance

Besides unexpected breakdowns, a generating unit is taken off-line for preventative maintenance, which represents between 2 percent and 15 percent of the total time period. In most models maintenance is taken into account by reducing the available generating capacity by a maintenance factor. Since one of the purposes of the DAMES DISPATCH model is to study the need for additional capacity, the method of reducing the available generating capacity would introduce an unacceptable bias toward additional capacity. In the real world, maintenance is scheduled for off-peak periods, so rather than reducing available generating capacity, the model will reduce the amount of time a unit can be run, thus scheduling maintenance for the off-peak periods. Table 5-7 summarizes the proportion of time in which a unit is unavailable because of maintenance. Since units cannot run 100 percent of the time, units which are not fully utilized must produce the energy for those that are down for maintenance. The situation is illustrated in Figure C-3. In that figure the lower hatched area represents energy required when unit types 1 and 2 are in maintenance. The upper hatched area represents energy from unit types 2, 3, and 4 to meet this requirement. The hatched areas represent energy quantities calculated by the programs; their location on the figure does not represent the actual time when the energy is produced. The right edge of the upper hatched area has an abscissa equal to the time when the unit is not scheduled for maintenance.

C.3.5 Minimum Running Time

In the simulation of a system, the most economical units are dispatched first. If the generating capacity of those units when running is sufficient to meet the peak demand, the other units are never turned on. In the real world, however, unless a unit is deactivated or mothballed, it must be turned on from time to time if only to be maintained in operational condition. The deactivated units are known, and the supply algorithms take their status into account. A minimum running time is set by the model to force all units to be used. This minimum running time is a percentage input specified by the user of the model (usually 5 to 10 percent), which forces all units to be used.

C.3.6 Dispatch Order

One of the most critical assumptions of the model is the order in which generating units are placed in service. The fuel types and dispatch order are

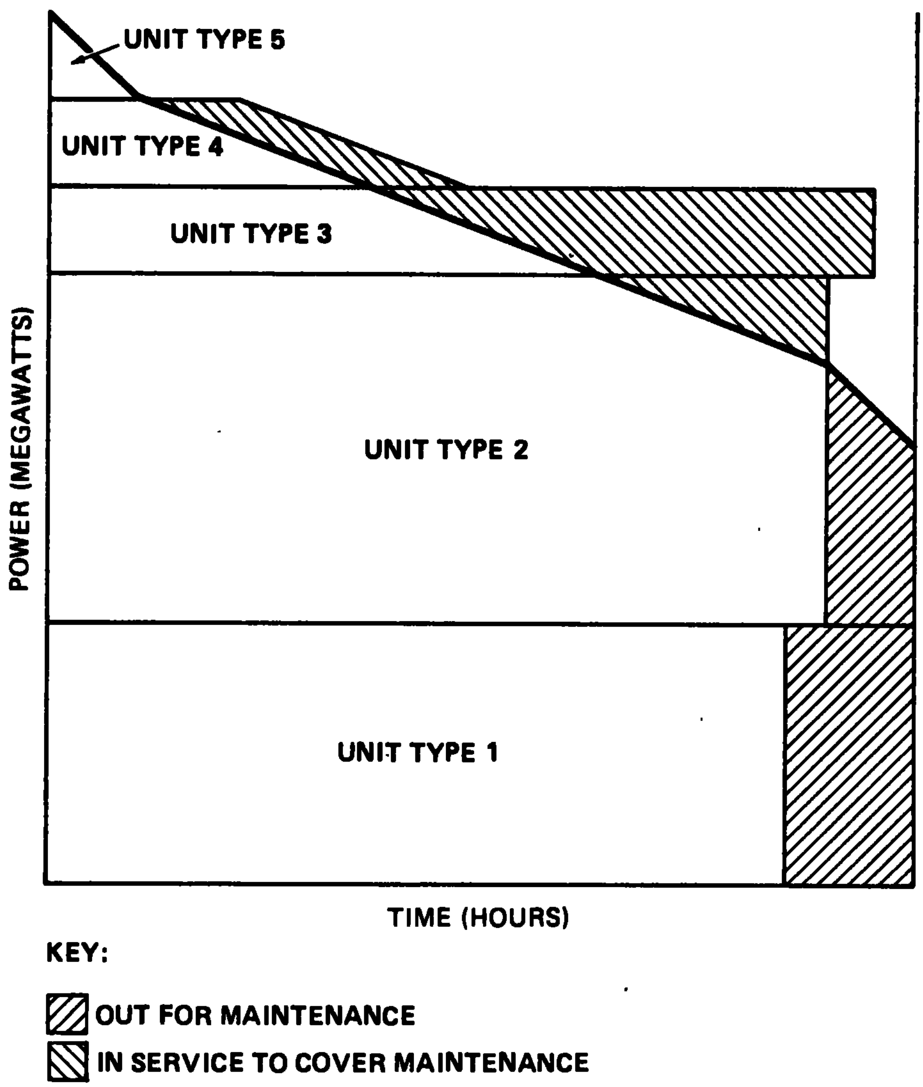


FIGURE C-3

MAINTENANCE ADJUSTMENT

DAMES & MOORE

summarized in Table C-1, which represents the initial loading order without pumped storage. The dispatch order of fuel types is determined on the grounds of economic efficiency; the most economically efficient fuels will be dispatched first. The model, however, has several options or running modes that can introduce different categories of units and therefore modify the dispatch order. The model can be used to estimate the capacity needed to satisfy the demand for electricity according to different conditions. In some of these conditions, future capacity expansion (as known at this time) might not be enough to satisfy the demand. The model then will introduce new unsited capacity, both base loaded and peaking. These are two fuel types introduced by the model. Their loading order is shown in Table C-2 (these new generators will be the most efficient units possible, hence their position in the dispatch order).

C.3.7 The Special Case of Hydroelectricity

Hydroelectric is probably the most difficult generation to simulate since there are three types of generation.

The first type is run-of-the-river hydro. The run of the river is the percent of generation produced by water flowing through the dam at a level that will accommodate minimum flow requirements. Often, a specific minimum amount of water goes through the dam to satisfy government regulations, to be available for irrigation, to maintain fisheries, etc. Since this generation is always available and the fuel is free, it is considered a base-loaded type of generation and first in the dispatch order.

The two other types of hydro generation are considered peaking generation. Since water can be stored behind a dam and its potential energy can be liberated on relatively short notice, the hydro generation is used in peak periods. The water can be accumulated behind the dam by the normal flow of the river or by pumping the water from a lower level, and unlike most other types of generation, the efficiency of the water turbine does not depend on a narrow operating range. Hydro dispatch is therefore used to stabilize the load on other base or intermediate units. This dispatch is called load leveling dispatch.

The generation of electricity from water that has been pumped from a lower level is called pumped storage. The economics are quite simple: Very often it is relatively inexpensive to run a base-loaded unit during off-peak hours to generate the electricity to activate the pumps. Instead of turning on units that burn an

TABLE C-1

DAMES DISPATCH Initial Dispatching Order

Order	Fuel Type
1	Hydro
2	Nuclear
3	Coal steam
4	Gas steam
5	Oil steam
6	Gas combined cycle
7	Oil combined cycle
8	Gas combustion turbines
9	Oil combustion turbines
10	Other

TABLE C-2

Running Mode - Base/Peak,
Last Base Fuel/Unit Type - Coal Steam,
Last Fuel/Unit Type Cheaper than Pumped Storage - Gas Steam

Dispatch Order

1 Hydro

Base Type Units

2 Unsited base units
3 Nuclear
4 Coal steam

Peaking Type Units

5 Unsited peaking units
6 Gas steam
7 Pumped storage
8 Oil steam
9 Gas combined cycle
10 Oil combined cycle
11 Gas combustion turbines
12 Oil combustion turbines
13 Other

expensive fuel like gas or oil to generate electricity, the pumped energy is then liberated in a peak period. To implement the concept in the model, some additional information is needed. The user of the model has to choose which type of generation in the dispatch order is inexpensive enough to fuel the pumping portion of the operation, and also which fuels are cheaper or more expensive to use than pumped storage. In other words, the user can determine where pumped storage is placed in the dispatch order. The model assumes a round-trip efficiency of 72.25 percent for pumped storage generation; that is, the base-load unit has to generate 27.75 percent more electricity (to pump the water uphill) than can be retrieved later on (by letting the water run through the turbines). The mechanisms for pumped storage are shown in Figure C-4.

The amount of energy available through hydroelectric generation depends, of course, on the amount of water available. To simulate the different conditions of drought or abundant rainfall, a hydro adversity factor is used as an option in the model. This factor is supplied by the user and then used to change a set of normal or base water conditions from abundant to adverse, depending on the numeric value of the factor. The normal conditions are the 1979 regional values for the water supply; these 1979 conditions have been translated into capacity factors, which the hydro adversity factor then modifies.

C.4 THE DISPATCH PROGRAM

The DISPATCH program can be used with two different running modes: BASE/PEAK and PURCHASE/SALE. The first option forces the program to compute new, unsited capacity. The second option only tallies the energies by assuming that the needs can be covered by purchases and that any excess base generation can be sold. The second option was not necessary in the present study.

The program starts by the necessary data acquisition, prompting the user for file names and options as follows:

- One file containing supply and demand information by season, year, region, and fuel type. This file also contains titles, reference year, and the conditions or scenarios that created the supply and demand information.
- One file containing the base or normal hydro conditions by region. The file also contains the hydro capacities and the run of the river generation.

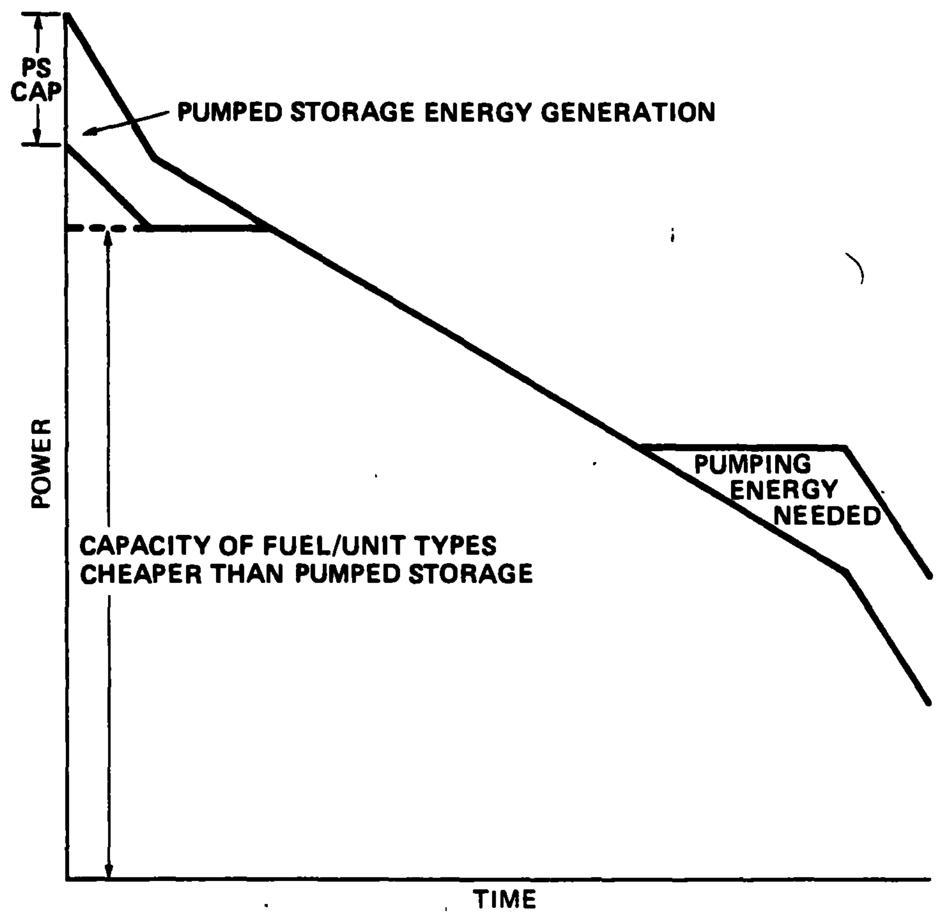


FIGURE C-4
PUMPED STORAGE

DAMES & MOORE

The other inputs are:

- The running mode option
- The last fuel type used as a base loaded type
- The last fuel cheaper than the pumped storage
- The hydro adversity factor
- The minimum running time for all fuel types.

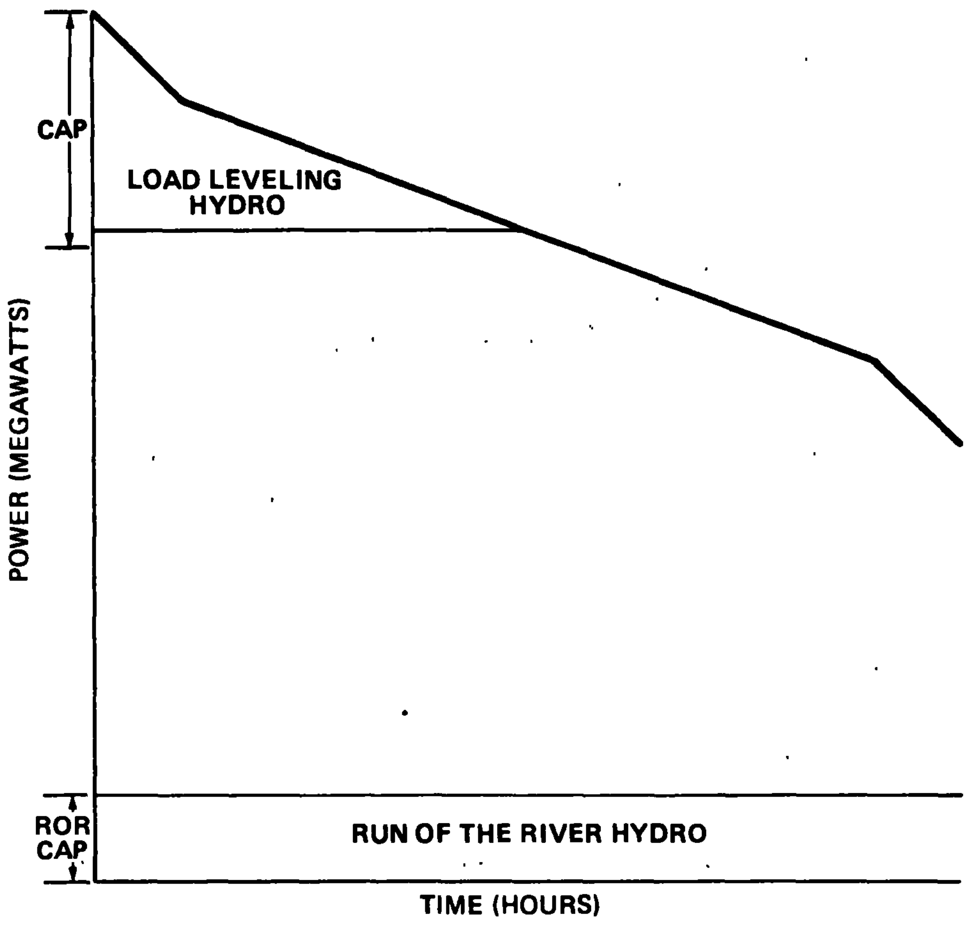
After these inputs are read by the program, the loading order of the fuels is adjusted accordingly. The hydro energy and capacities are summed up for the region studied, and the energy from the run-of-the-river hydro is calculated. The actual dispatch is then performed for each season.

For any particular season, the generating capacity available from each fuel, the demand, and the available energy are read from the file. If the fuel type, "OTHER," has a negative capacity (from untyped retirements), then that capacity is deducted from the capacity available from the fuel type, "OIL." The generic load duration curve is adjusted and normalized (Section C.3.2). A check is made after the adjustment to find out if the LDC has a reasonable shape and has not been distorted by incorrect data.

The first fuel dispatched is base-loaded run-of-the-river hydro. If any hydro energy is still available, it is used as peaking hydro and dispatched starting from the top of the LDC. (The effect of this load-leveling dispatch is illustrated in Figures C-5 and C-6.) At this point, the LDC is redrawn. It should be noted that the leveling effect of the hydro dispatch may be limited by either available energy or available capacity as shown in the figures cited.

The model then determines if there is sufficient generating capacity to meet the remaining demand. This is done by summing the effective capacity of all non-hydro units (including any unsited capacity that the model has previously put into service), and adjusting the pumped storage capacity so that no more is included than the current system can support. If there is insufficient generating capacity, DISPATCH is used as a simplified generating system expansion planning model that adds what is needed in the form of unsited base and unsited peak capacity.

In this study two different expansion plans were used: in the first, peaking was furnished by pumped storage and in the second, peaking was furnished by fossil-fueled units. The calculations for the required additional base and peaker capacities are different for the two expansion plans, and are described separately.



RORCAP = CAPACITY USED TO PRODUCE RUN OF THE RIVER ENERGY
CAP = AVAILABLE HYDRO GENERATING CAPACITY

FIGURE C-5
DISPATCHING OF HYDRO

DAMES & MOORE

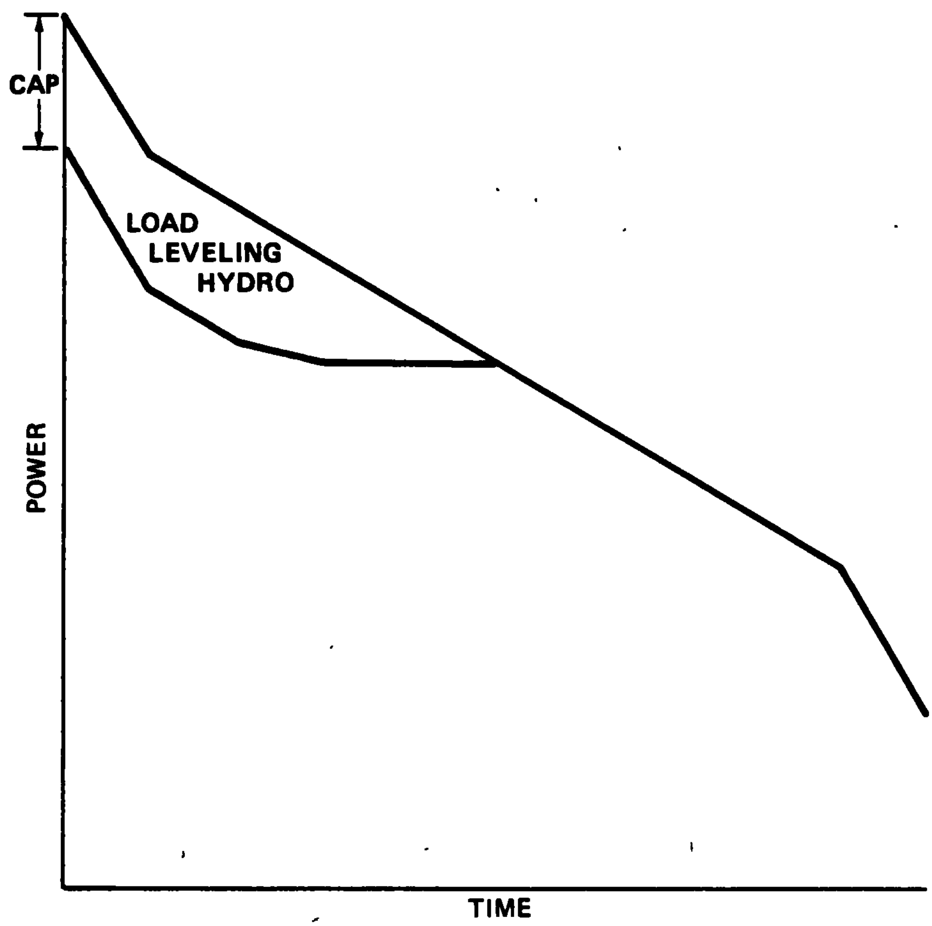


FIGURE C-6
DISPATCHING LOAD LEVELING HYDRO

DAMES & MOORE

C.4.1 Added Pumped Storage

In this case either unsited base capacity or additional pumped storage capacity or both may have to be added. These additions will replace all peaking units more expensive to operate than pumped storage, and will effectively retire these units. The amounts of base and pumped storage capacity to be added are calculated in the program by an algorithm based on two conditions:

- Total effective capacity must equal peak load
- Energy available for economical pumping must equal energy generated by the pumped storage plus its pumping and generating losses.

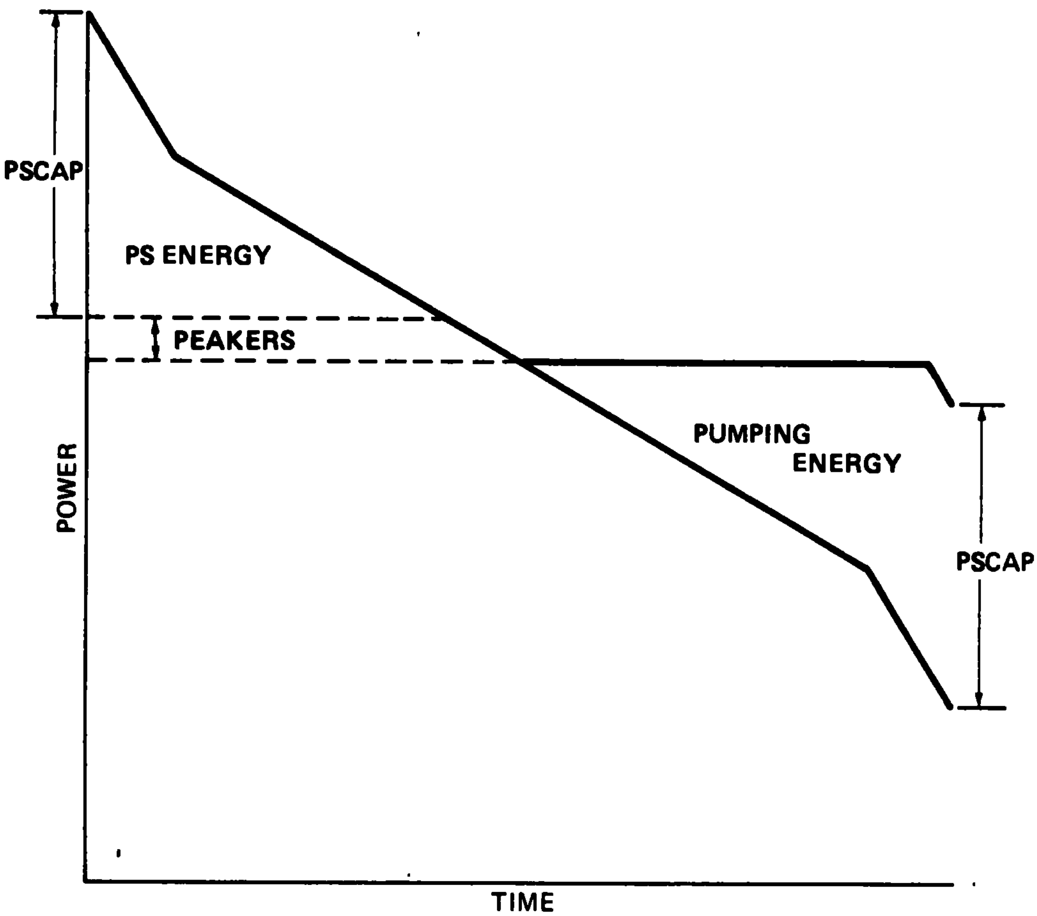
Expressions for the pumping and generating areas on Figure C-7 were used to develop equations expressing these two conditions. The equations were solved simultaneously to obtain the amounts of added base capacity or added pumped storage capacity to be used in the dispatch.

C.4.2 Added Fossil Peakers

Unsited base capacity is added to the system in an amount equal to the amount of additional capacity needed by the system. However, to avoid running base-loaded units inefficiently, the model requires that these units run for at least 20 percent of the time period. (Thus, the amount of additional unsited base capacity added is not permitted to cause any existing base-loaded unit to run less than 20 percent of the time period.) After the additional unsited base has been determined, any additional capacity needed is added as unsited peak units.

Pumped storage is then dispatched from the top down, much as peaking hydro is dispatched, except than when the LDC is redrawn, area is also added under the LDC to provide pumping energy (Figure C-7). The program then uses a normal stacking dispatch for the remainder of the units under the redrawn LDC, after each of these units have been switched on for the minimum running time specified by the user.

In the last step, the dispatch is adjusted to account for maintenance (Section C.3.4) by shortening the running time of base-loaded units to allow for their maintenance. The intermediate units then run a little longer to generate the missing energy. Since the model will not allow peakers to be used as base units, maintenance-induced energy deficits that intermediate units cannot satisfy must be supplied by additional new unsited capacity.



PSCAP = MAXIMUM PUMPED STORAGE CAPACITY

PEAKERS = UNITS CHEAPER THAN PUMPED STORAGE BUT NOT USED TO PRODUCE PUMPING ENERGY

PS ENERGY = PUMPING ENERGY – LOSSES

FIGURE C-7
MAXIMUM PUMPED STORAGE

DAMES & MOORE

At this point, the dispatch is complete. The computer program will compute capacity factors for all fuel types and store the generation and capacity factors in two separate files.

☆U.S. GOVERNMENT PRINTING OFFICE: 1982-391-89