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History of First U.S. Compressed Air Energy Storage (CAES) Plant (110-MW–26 h)

Volume 1: Early CAES Development

Prepared by
J. O. Goodson
Site Engineer, CAES Plant

REPORT SUMMARY

History of First U.S. Compressed Air Energy Storage (CAES) Plant (110-MW–26 h)

Volume 1: Early CAES Development

In 1991, Alabama Electric Cooperative's 110-MW–26 h compressed air energy storage (CAES) plant, the first in the United States, became commercially operational. This report, first in a series, documents the history of the plant from project conception to the beginning of plant construction.

INTEREST CATEGORY

Compressed air energy storage

KEYWORDS

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BACKGROUND Since 1975, when it first began research on CAES, EPRI has maintained continuing efforts to interest the electric utility industry in CAES as a viable storage alternative. CAES plants use both electric energy (approximately 0.80 kWh input for each kWh output) plus fuel (4570 BTU input/per kWh output). Previous experience with CAES includes one 290-MW–4 h plant in service in Germany since 1978. Alabama Electric Cooperative (AEC) took the lead in building the first plant in the United States, a plant that included a first-of-a-kind EPRI-developed recuperator to improve plant fuel consumption by about 25%. The EPRI role also included technical and engineering support during all phases of the project, documenting project progress via an engineer-of-record, and funding of specialized plant instrumentation and analyses.

OBJECTIVE To document the history of the first U.S. CAES plant from early interest in the technology by AEC through the economic feasibility, environmental permitting, and engineering that led up to the construction of the plant.

APPROACH The writer interviewed key utility, contractor, and EPRI personnel and used engineering diary information logged by an EPRI site and field engineer to document the history of the AEC plant.

RESULTS This report is a chronological record of early U.S. CAES developments including load- and generation-planning studies, power supply study results, conceptual engineering designs, project administration activities, design specifications, contract requirements, environmental and licensing documents, and construction planning activities. It covers the AEC project from its earliest stages to contract execution on July 29, 1988. Volume 2 of this report will cover the construction period, which formally terminated at midnight, May 31, 1991. Volume 3 will document plant testing, operation, and maintenance.

EPRI PERSPECTIVE The planning, engineering, construction, and operation of the AEC plant has proved that CAES in the 100-MW size is economically and environmentally attractive. No major problems were encountered during the early stages of planning or during the engineering of this plant. As a result of initial economic studies, it was discovered that one 100-MW plant would be more economical than two 50-MW units. Thermodynamic studies indicated that cavern wall effects on stored-air temperature required a cavern that was about 25% larger than the size initially proposed. An economic study showed CAES to be preferable to other alternatives for the load projections and load shape forecast by AEC. These and other results connected with this plant and other attractive future CAES plant configurations will aid utilities in their efforts to evaluate and build CAES plants.

PROJECT

RP2894-01
Project Manager: Robert Pollak
Generation & Storage Division

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Prepared by
J. O. GOODSON
Site Engineer, CAES Plant

Prepared for
Electric Power Research Institute
3412 Hillview Avenue
Palo Alto, California 94304

EPRI Project Manager
R. Pollak

Energy Storage Program
Generation & Storage Division

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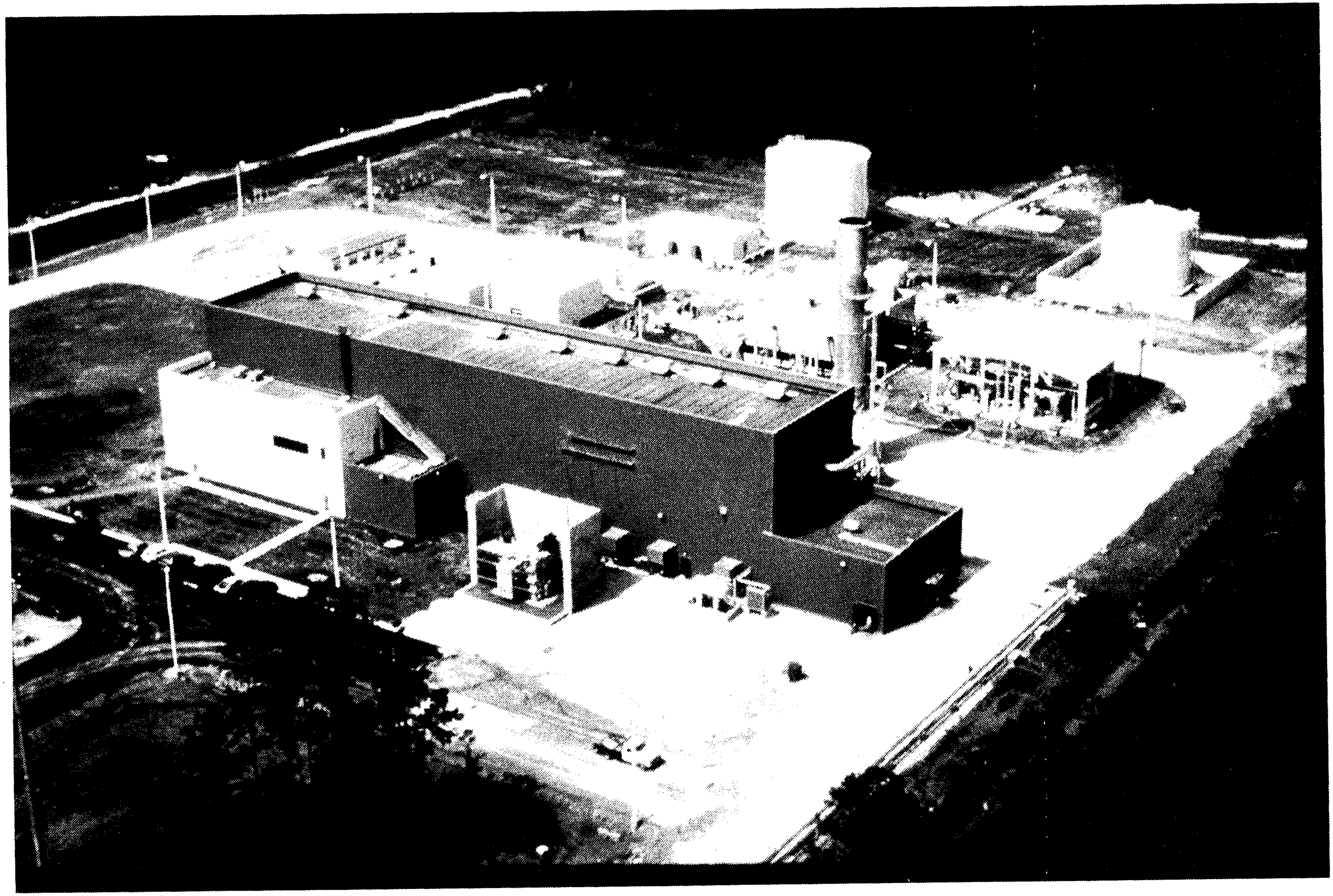

Aerial View, AEC 110 MW - 26 hr CAES Plant

ABSTRACT

This is the first of three volumes which document the historical development of the first U.S. compressed-air energy storage (CAES) power-generation facility. Volume 1 is a background report and presents a chronicle of the development of the CAES facility from the early interest in CAES until inception of engineering/construction on August 11, 1988. The 110 MW - 26 hr CAES plant is owned and operated by Alabama Electric Cooperative, Inc. (AEC) of Andalusia, Alabama. The plant is the first CAES plant in the United States and the world's first CAES facility incorporating a recuperator to improve efficiency. The plant supplies competitively priced peaking power to the AEC owner members. The economics of CAES-produced power is attractive because the energy-intensive air-compression mode is powered by relatively inexpensive base-load power external to the CAES plant. The compressed-air energy is stored underground until needed, and during the power-production mode, the only fuel required is that to heat the compressed air to expander-inlet temperature. The project development for AEC's CAES plant involved much planning and preliminary design work. Specifically, this included load and generation-planning studies, power-supply selections, conceptual designs, project administration, air-storage cavern and turbomachinery specifications and design, contract requirements, environmental and licensing issues, and construction planning.

FOREWORD

This is the first of three volumes documenting the inception, design, construction, and initial operation of the first compressed air energy storage (CAES) plant in the United States. This document, Volume 1, relates the history of the project from the origin of CAES technology to the contract execution on July 29, 1988, which allowed engineering and construction to proceed on August 11, 1988. The system-planning data in this volume reflects the mid-1980s when the CAES plant was being considered for construction. Volume 2 will cover the construction period, which formally terminated at midnight on May 31, 1991, when the plant became available for commercial operation. Volume 3 will document plant testing, operation, and maintenance.

ACKNOWLEDGMENTS

Alabama Electric Cooperative, Inc. (AEC) is a progressive cooperative-owned utility, whose purpose is to provide a reliable source of power to its members at the lowest possible cost. It is pursuing this purpose in part by utilizing CAES in its generating mix. This CAES plant is the first to be built in the United States. AEC personnel, whose efforts were instrumental in the selection and development of CAES technology are listed below.

Charles R. Lowman	Executive Vice President & General Manager, Retired
James A. Vann, Jr.	Executive Vice President & General Manager
Ray Clausen	Division Manager, Engineering & Operations
John Howard	Division Manager, Power Production & Construction
David Lord	Department Manager, Systems Planning
Robert Meyer	Project Manager, Power Plant Construction
Shannon Brabham	Project Engineer
John Tisdale	Plant Manager, Central Generation

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Section 1

EXECUTIVE SUMMARY

The first CAES plant in the world was the 290 MW - 4 hr (50 Hz) CAES plant at Huntorf, Germany, built in 1978 by Northwestdeutsche Kraftwerk (NWK). Its success enhanced the possibilities for CAES plants to be constructed elsewhere. As such, the CAES-plant concept was selected by EPRI as an idea deserving application. Cost analyses and engineering studies were performed in the late 1970s (see Figure 1-1) to determine benefits to the U.S. utility industry through the use of CAES plants. Also investigated was the availability of proven equipment suitable for use in CAES plants.

In 1981, Soyland Power Cooperative of Decatur, Illinois initiated the Soyland CAES construction project (220 MW - 11 hr). Unfortunately, the project was abandoned in February 1983, not because of any intrinsic difficulty but as a result of a policy decision of the Soyland Board of Directors to revert to a transmission/distribution cooperative and not to assume the burden of becoming a generation-based cooperative utility.

During the period, 1977 through 1990, EPRI published 56 reports directly related to the analysis and U.S. development of compressed-air energy storage technology. A list of these EPRI reports is given in Appendix A.3. These reports represent the results of studies undertaken in an effort to reduce the cost of a CAES plant and reduce the time required for plant construction. Portions of these studies used the concept (denoted as mini-CAES) of shop-fabricated, skid-mounted units which would minimize field-construction cost and time. The studies included analysis of air storage in hard-rock caverns, salt caverns, and aquifers configured with 25-MW and 50-MW generation-unit modules. The bids obtained for the these units determined that all plant equipment was commercially available as manufacturers' standard production units which had a history of proven operation. Conceptual-design studies and cost estimates were developed for these relatively small CAES plants (see EPRI Report EM-3855 for details.) With this information EPRI continued efforts to interest the electric power industry in CAES plants as a viable power-storage concept. The practice of underground gas storage was foreign to the electric power industry, and acceptance was difficult, even with the long history (over 50 years) of operating such storage for liquid and gas hydrocarbons in the oil and gas industries.

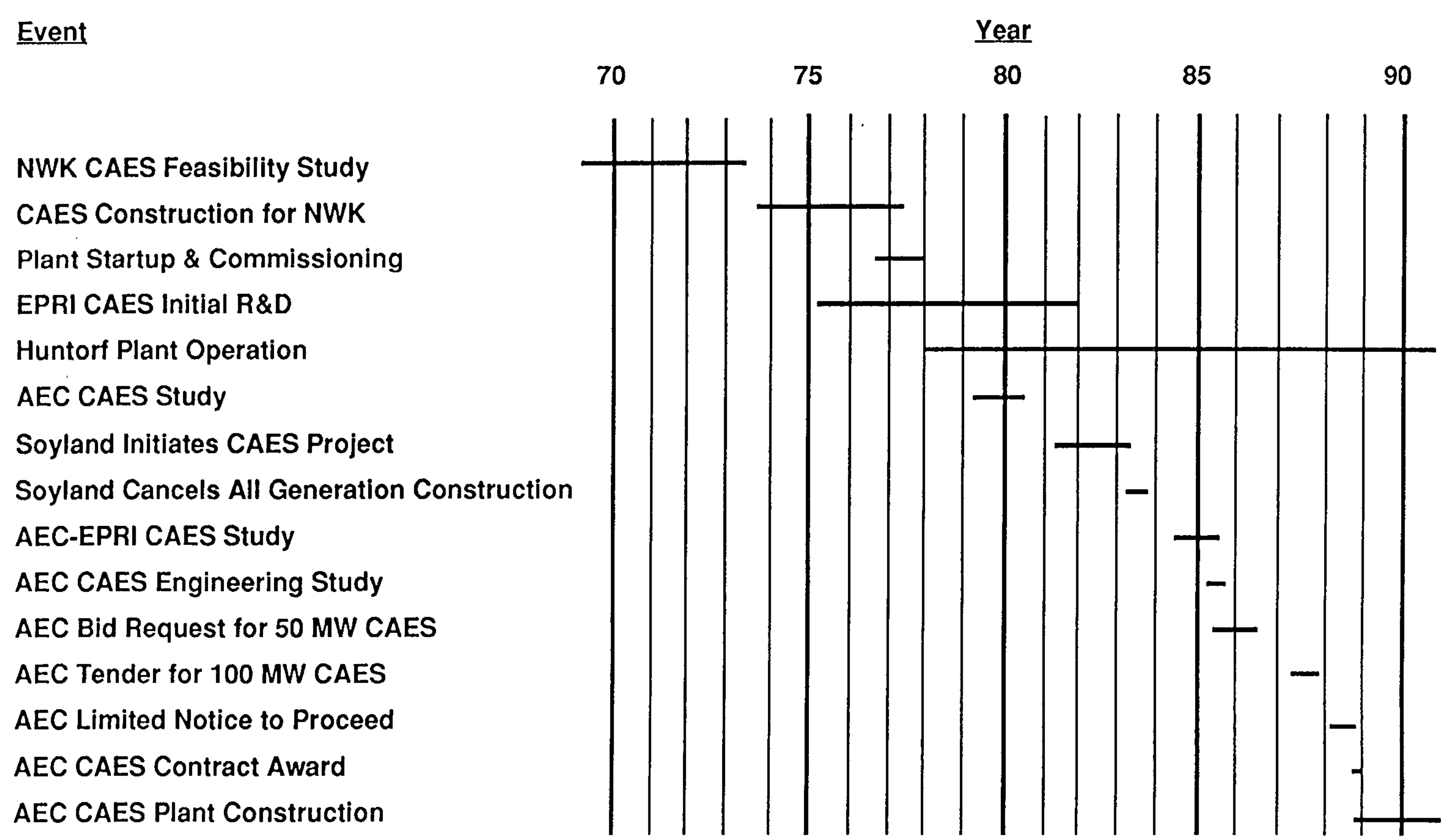

Figure 1-1. Historical Perspective for Important CAES Events

Alabama Electric Cooperative (AEC) had been contacted by equipment suppliers attempting to promote CAES equipment and was also aware of the CAES concept via industry sources. AEC's system-planning engineers included CAES plants in their studies of power-supply options. In 1979 AEC and South Mississippi Electric Power Association (SMEPA) engaged United Engineers & Constructors, Inc. (UE&C) to perform a feasibility study for a CAES Plant to be jointly owned by AEC and SMEPA. The study results indicated that the benefits to SMEPA were not sufficient to proceed but did indicate that a CAES plant would be beneficial to AEC or others, whose peaking/intermediate capacity required the construction of additional generation capacity.

AEC's interest in CAES continued, and in 1985 AEC's Board of Trustees approved funding for a study, which EPRI and AEC funded jointly, to verify costs, locate a site, and provide data for environmental permitting. Burns & McDonnell prepared the bid specifications and documents required for the request for tender of the CAES plant. During August 1986, bid specifications were issued for a 50-MW CAES plant. The bids were received in July 1987 from Gibbs & Hill, Bechtel, Comstock, and United Engineers. The Gibbs & Hill bid used Dresser-Rand Turbomachinery equipment, whereas the others used Asea-Brown-Boveri's. During the review and negotiations for the 50-MW plant, it became apparent to AEC and EPRI that the expansion-turbine portion of the bid was based on a derated 100-MW capacity expansion turbine. The AEC plan to build four 50-MW units sequentially was revised to a plan to build two 100-MW units sequentially. This was done to take advantage of the economy-of-scale costs for the expansion turbine, compressors, cavern, and balance-of-plant components. Also, AEC needed 100 MW rather than 50 MW of new capacity to come on-line by mid-1991, as their load growth was greater than expected, and as a 50-MW hydro plant, which was in their generation plan, was delayed because of environmental problems. Specifications were resubmitted for bid, and the bids were received in September, 1987. The bids were evaluated, and Gibbs & Hill was determined as the lowest bidder with the best commercial terms. In January, 1988 Gibbs & Hill was notified of AEC's intent to negotiate with Gibbs & Hill exclusively to draft a mutually agreeable contract based on the 100-MW specifications.

The bid by Gibbs & Hill guaranteed to AEC a plant with maximum dependable capacity of 110 MW net, including a salt-dome reservoir capable of providing enough air to generate 2600 MW-hrs. As such, the plant is denoted as a 110 MW - 26 hr plant. A limited notice to proceed was given to Gibbs & Hill for project engineering and design in February, 1988.

Gibbs & Hill's inability by themselves to secure a bond (a Rural Electrification Authority requirement) resulted in the formation of a Harbert/Gibbs & Hill Joint Venture (JV) for the CAES project.

In May, 1988, the AEC Board of Trustees passed a resolution which approved contracting with the JV for CAES Project Contract 1. In July, 1988, Contract 1 between AEC and the JV was executed. Organization charts for this CAES project are given in Figures 1-2 and 1-3. The first construction was begun by Fenix & Scisson, a subcontractor to JV, in early August, 1988, with the arrival of a drilling rig on-site to begin work required to develop the salt cavern for the air-storage reservoir.

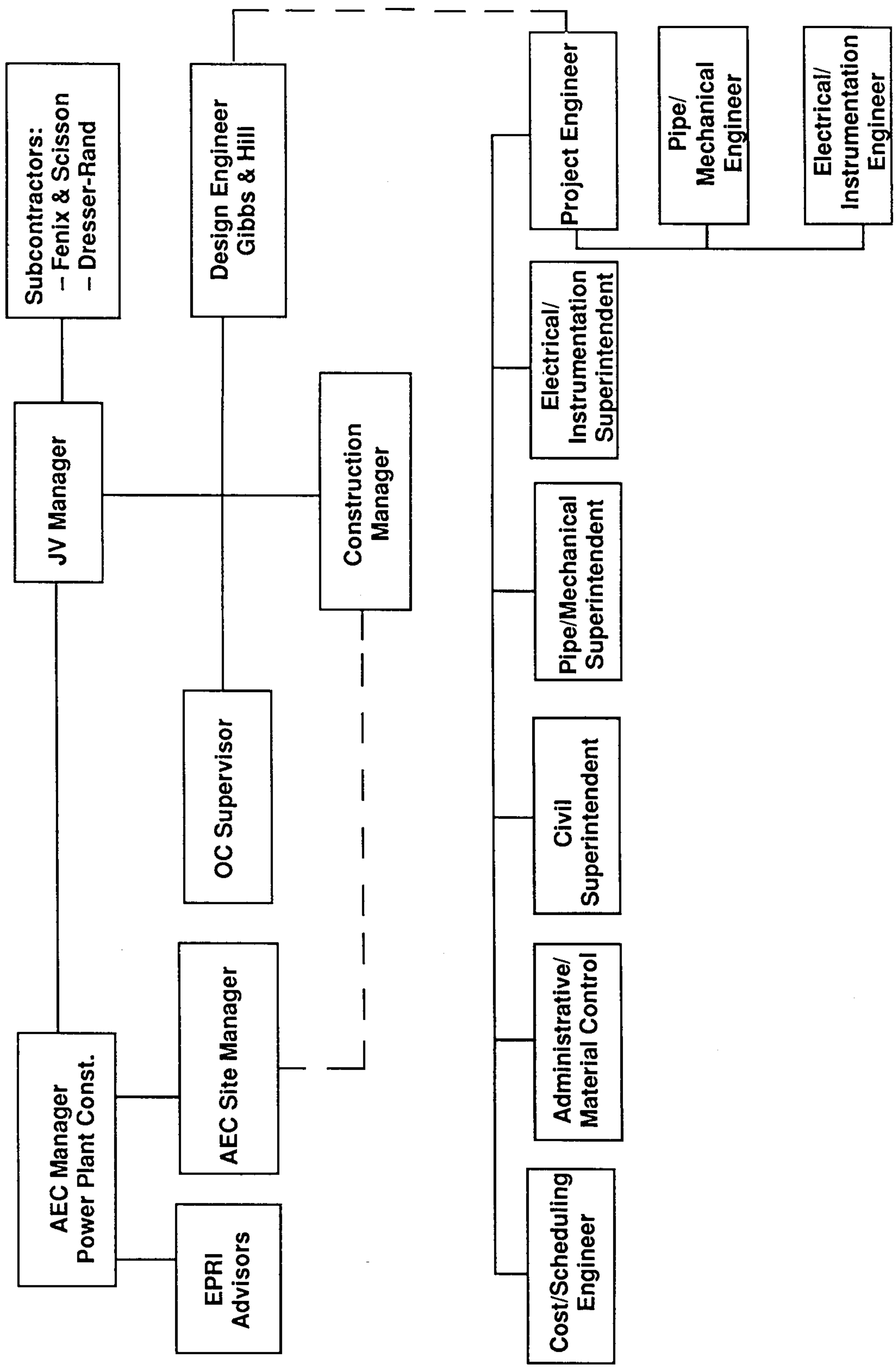

Figure 1-2. Harbert (Partner in Joint Venture) Construction Organizaton Chart for the CAES Project

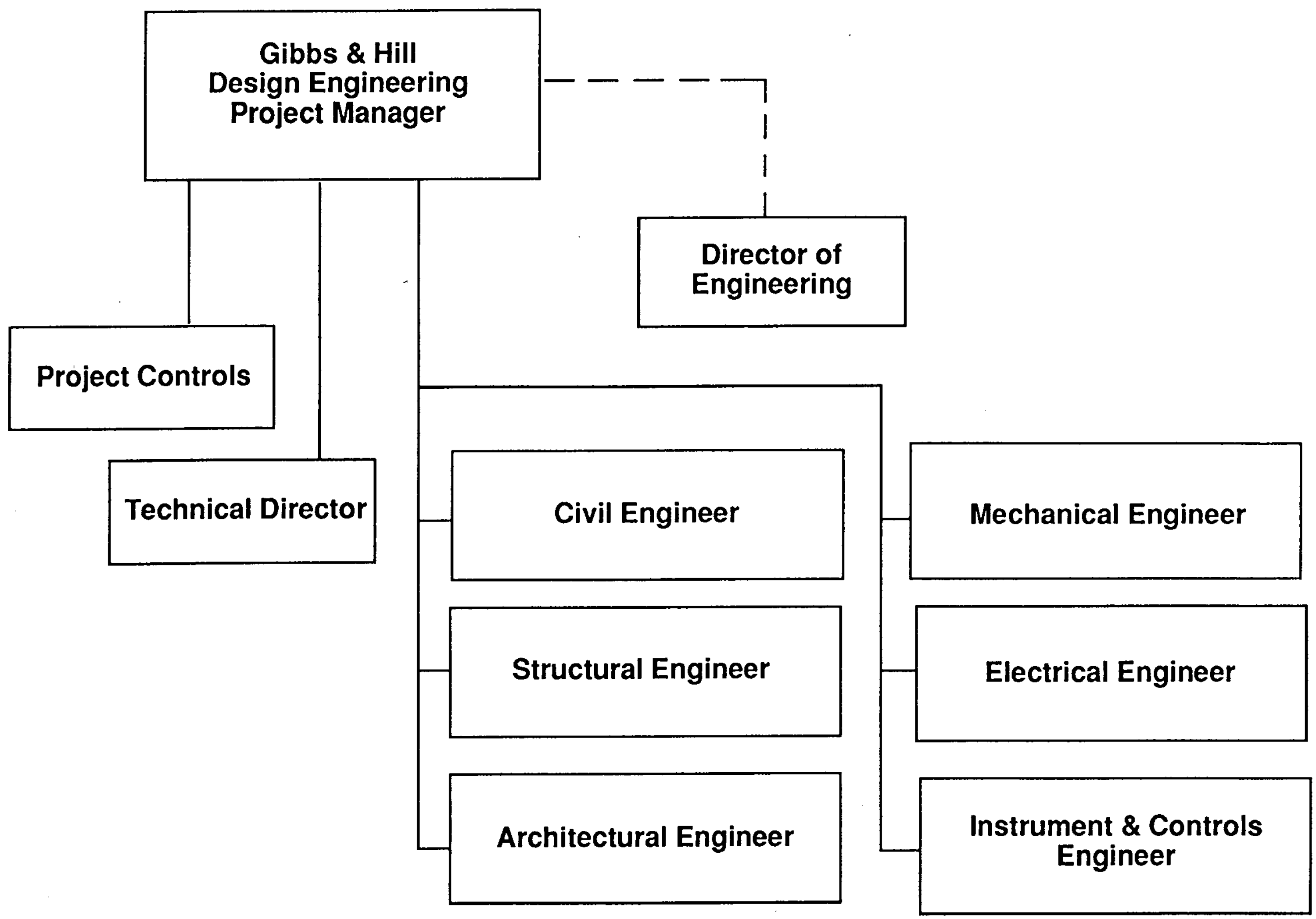

Figure 1-3. Gibbs and Hill (Partner in Joint Venture) Design Engineering Organization Chart for the CAES Project

Section 2

CHRONOLOGY OF IMPORTANT CAES EVENTS/MILESTONES

1969 CAES-plant feasibility study by Northwestdeutsche Kraftwerk (NWK).

1973 NWK places order for construction.

1974 NWK starts construction of Huntorf plant.

1975 EPRI begins research on CAES plants.

1977 Construction of Huntorf plant completed.

1978 Huntorf plant operational.

1979 United Engineers and Constructors (UE&C) approaches AEC with the purpose of promoting a CAES plant. UE&C proposes study to be conducted for AEC and South Mississippi Electric Power Association (SMEPA). AEC Board of Trustees approves proceeding with study of UE&C for AEC and SMEPA for 220-MW CAES plant vs. 370-MW coal-fired generation plant.

1980 AEC Board of Trustees approves expanding study being done by UE&C. Study of UE&C shows that CAES plant would be economically feasible to AEC with 100 MW installed in 1987 and 100 MW installed in 1992.

1981 Soyland Power Cooperative signs contract and initiates program to build a 220 MW - 11 hr CAES plant, using a rock cavern as the air-storage reservoir.

1983 Soyland Power Cooperative discontinues program to become a generation-based cooperative, and as a consequence, their 450-MW coal plant (under construction), as well as their CAES-plant contract, are cancelled.

1985 AEC Board of Trustees approves joint study with EPRI to verify evaluation, locate plant site, and provide data for environmental permitting. Energy Management Associates conducts study of CAES plant vs. AEC's source alternatives. Gibbs & Hill completes preliminary engineering study for AEC on CAES plant using up to four 50-MW units.

1987 AEC issues request for bids for CAES plant. AEC receives bids for CAES plant.

1988 AEC awards contract for CAES plant to Joint Venture (Harbert/Gibbs & Hill).

1991 Construction of first U.S. CAES plant completed.

Section 3

SYSTEMS PLANNING

Alabama Electric Cooperative Systems Planning Department prepared a Power Requirement Study in 1984 with the cooperation of representatives of each of AEC's member-owners. A simplified but consistent forecasting procedure was used for AEC's municipal and industrial members. The overall forecasting procedure consisted of the following five basic steps:

1. Individual energy and noncoincident peak-demand projections were developed for each member. A consistent methodology was used for each of the 16 distribution cooperatives, as summarized below:

    a) Residential consumer forecasts were developed on basis of published county population projections. Adjustments to forecasts were made if member's future customer growth patterns were likely to divert from historical growth patterns for clearly identifiable reasons.

    b) Simple econometric models were developed to quantify historical inter-relations between average residential use and changes in price of electricity, per capita income, and weather-related factors.

    c) Simple econometric models were developed to relate nonresidential sales to the number of residential customers, the price of electricity, and weather-related factors.

    d) Econometric models were used to convert independent forecasts of number of residential customers, price of electricity, per-capita income, and average weather conditions into energy-saving forecasts. Simply stated, the models utilize projections of residential consumers, price of electricity, and per-capita income as surrogates for all the factors which determine usage of electricity.

2. The individual member forecasts were summed to obtain energy forecasts for the AEC system after accounting for distribution and transmission losses. Generally, losses were assumed to remain at recent historical levels, although a few adjustments were made for those member-distribution cooperatives which are taking clearly identifiable steps to minimize distribution losses.

3. Energy sales forecast was converted into associated demand forecasts for each member of the entire AEC system.

4. Energy and demand forecasts were related to AEC's existing generation capability.

5. Sensitivity of forecasts to variations in projected conditions were analyzed to bracket the most probable forecast between possible high- and low-growth scenarios.

The AEC composite forecast was derived by summing the most probable forecast for the 16 distribution cooperatives, four cities, and two industries, which comprised its membership at that time.

3.1 Load Projections

Sales were forecast to increase at an annual rate of about 4.4% from 1984 through 1989, 3.3% from 1989 through 1994, and 2% from 1995 through 1999. The 4.4% growth rate projected for the first five years was more robust than the 2.8% rate actually experienced from 1979 through 1984 and was comparable to the growth experienced from 1974 through 1979.

The forecast energy sales growth is not uniformly distributed among AEC's members. Nine distribution cooperatives (West Florida, Excambia River, Clarke-Washington, South Alabama, Pea River, Southern Pine, Wiregrass, Covington, and Pioneer) were forecast to experience energy sales increases in the 2% range. Each of these member cooperatives is located in a rural area geographically removed from major metropolitan growth centers and coastal development. The four city-member cooperatives (Andalusia, Brundidge, Elba, and Opp) were generally projected to experience sales increases of about 1.3%.

Andalusia is an exception to this, inasmuch as AMOCO Fabrics, which accounted for nearly 50% of the Andalusia load, was anticipated to install additional capacity within the next few years. AEC's industrial members were forecast to experience little or no growth over the projection period.

Five member cooperatives (Dixie, Tallapoosa River, Central Alabama, Coosa Valley, and Gulf Coast) were forecast to experience energy sales increases of 3% to 5% over the following five years. Each of these cooperatives is located within commuting distance of major metropolitan areas and is sharing to some extent in the growth of the urban centers. The Gulf Coast region was forecast to be the most rapidly growing, due to the growth around Panama City extending into the AEC service area.

The two major contributors to the overall energy sales picture were Baldwin County and Choctawatchee. Baldwin County experienced an average annual compound energy sales rate of 7.2% between 1979 and 1984. Condominium and other coastal development in the area was still accelerating, and growth was forecast to average 9% for the next five years. The forecast assumed that the building boom would level off in the 1990s; nonetheless, Baldwin County was forecast to account for about one-eighth of AEC's sales in the year 2000.

Choctawatchee's coastal area had experienced much less growth than Baldwin's County's, but building was accelerating. Choctawatchee experienced a 6.6% annual energy sales growth between 1979 and 1984 and was forecast to achieve an annual growth rate of about 10% for the following five years. The forecasts for Choctawatchee were similar to those for Baldwin County, except that the growth was lagging by about five years. Based on these forecasts, Choctawatchee would account for nearly one-eighth of AEC's total sales in the year 2000. Baldwin County and Choctawatchee combined were forecast to account for about one-quarter of AEC's total sales in the year 2000 and nearly one-half of the net system-wide growth over the forecast period.

Analysis of the historical record for each of AEC's member-owners indicates that load-factor usage (e.g., the ratio of average annual demand to peak demand) may not have exhibited any long-term trends. As a result, the energy forecast was converted into a peak-demand forecast by assuming that average historical relationships between energy use and peak demand will be representative for future conditions. In essence, AEC's peak during a "typical weather" year is forecast to increase at the same annual percentage rate as energy sales during the same year.

Alabama Electric Cooperative must have the capability to provide a dependable supply of electricity to its members. This is accomplished by forecasting future peak demand, allowing for transmission losses and possible equipment outages, and having the capability (through generation, purchases, and interchange agreements) to meet the forecast conditions. AEC's forecast capability requirement is shown in Figure 3.1-1. The integrated load includes the load connected directly to AEC's transmission system. The wheeling load includes the load "wheeled" or transferred over Alabama Power Company's or Gulf Power Company's transmission system. Note that during and after 1988 the wheeling load includes the same capacity as purchased through 1987 directly from Alabama Power Company and Gulf Power Company. Some energy loss is associated with all energy transfer operations. For the AEC system, transmission losses have averaged about 5%; losses are assumed to remain at present levels through the forecast period. A "reserve requirement" is necessary because some generating facilities will be inoperable during peak-demand periods despite adequate maintenance. The risk of major outages on AEC's system is reduced through interconnection agreements with neighboring utilities. These interconnection agreements contractually require AEC to maintain a 20% reserve requirement, which is a reserve capacity considered large enough to allow the interconnected utilities to have adequate generation available under virtually all possible conditions.

The energy and demand forecasts developed in the 1984 Power Requirements Study were based on a number of economic assumptions, including very moderate escalation in the real price of electricity, as well as moderate, continuous economic growth in the service area. AEC's sales are 82% to residential customers. As a result, the residential consumer forecast is the single largest factor affecting future energy sales. The consumer forecast calls for an overall consumer growth rate averaging about 1.6% annually, when Baldwin County and Choctawatchee are excluded from the totals. The rapid growth forecast for these two distribution cooperatives pushes the total consumer growth to the 2.6% level. The overall residential consumer forecast appears reasonable, given fairly good economic conditions necessary to promote coastal resort and other developments.

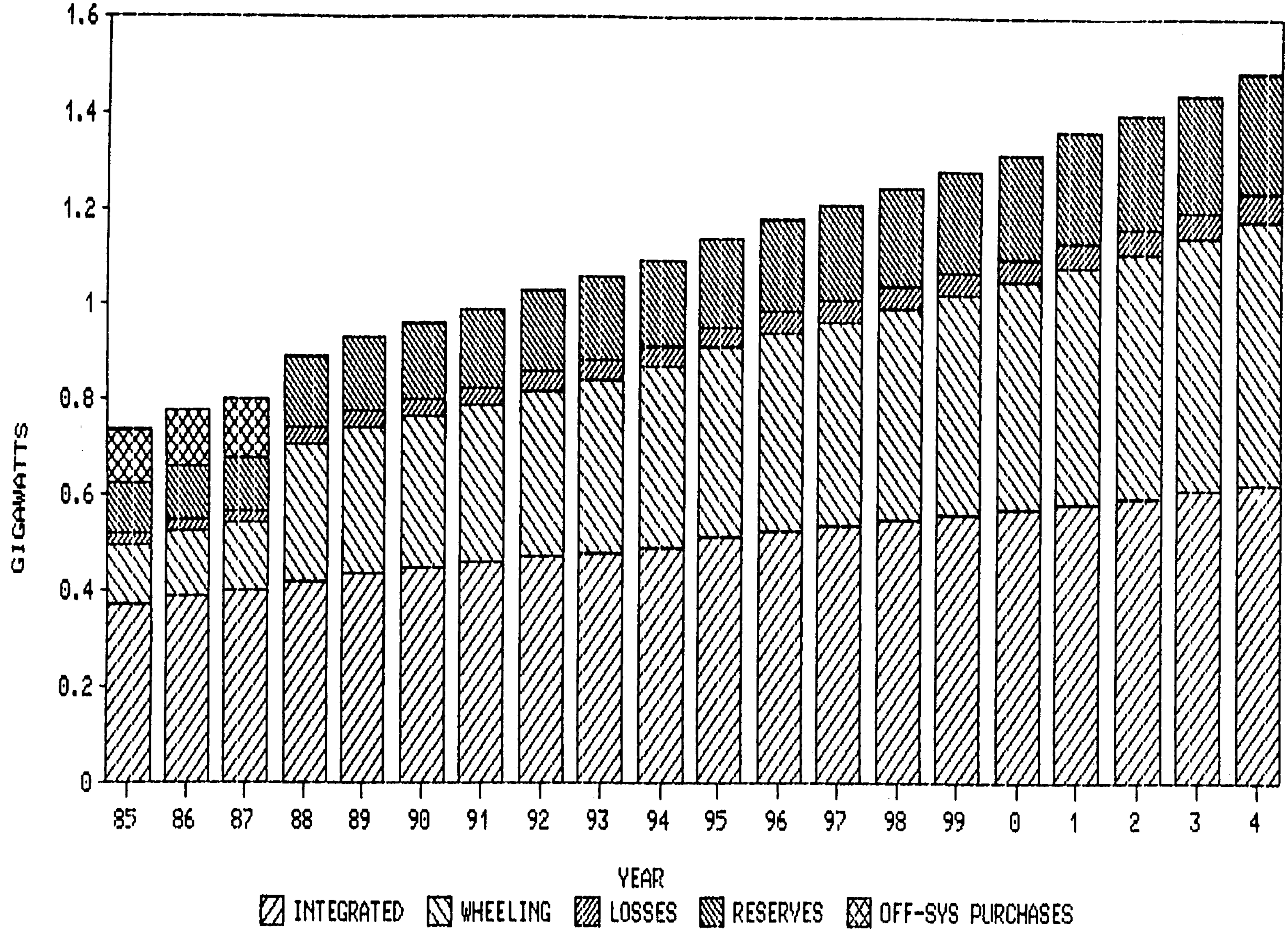

Figure 3.1-1. AEC Capacity Requirements

Average residential use was forecast to increase at an average annual rate of 0.88% annually, from 773 kWh/month in 1984 to 889 kWh/month in the year 2000. The fact that average residential use stagnated or declined slightly for each of AEC's 16 distribution cooperative members from 1977 through 1983 showed that use would not increase under generally poor economic conditions combined with significant electricity price escalation such as occurred during that period. The forecast usage was reasonably attainable with moderate levels of income growth and stable electricity prices. Under such conditions, forecast improvements in the efficiency of appliances and housing would be more than offset by increases in comfort levels and the saturation of electrical appliances.

Nonresidential energy sales were forecast to increase somewhat more rapidly than residential energy sales. This seemed reasonable due to the fact that a few cooperatives were thus experiencing suburban and resort development in formerly rural areas. The potential for growth in the number of commercial accounts in such developing areas would be much greater than for the systems as a whole. In any case, nonresidential sales comprised about 18% of the total system sales and were forecast to increase to about 20%. The forecasts were based on a rather comprehensive review of all available information and are reliable enough to serve as a basis for future planning. However, actual conditions could vary substantially from the mid-range forecast summarized above, and major decisions are made in full cognizance of that fact.

The 1984 Power Requirements Study forecast energy and demand requirements for 1985 which proved to be very close to what actually occurred. The peak demand during the summer of 1986 was approximately 80 MW greater than the forecast in Figure 3.1-2. The high summer peak-demand was partially due to a series of hotter-than-normal days, but it also indicated that the peak-demand forecasts included in the 1984 Power Requirements Study could prove to underestimate actual demand growth. While this did not present immediate problems for AEC, it did indicate the need to proceed with planned capacity increases at least as rapidly as were planned in 1986.

3.2 Energy-Supply Sources

AEC serves approximately 55% of the current load (integrated system) with its own generation and transmission systems; another 23% is served by AEC generation through

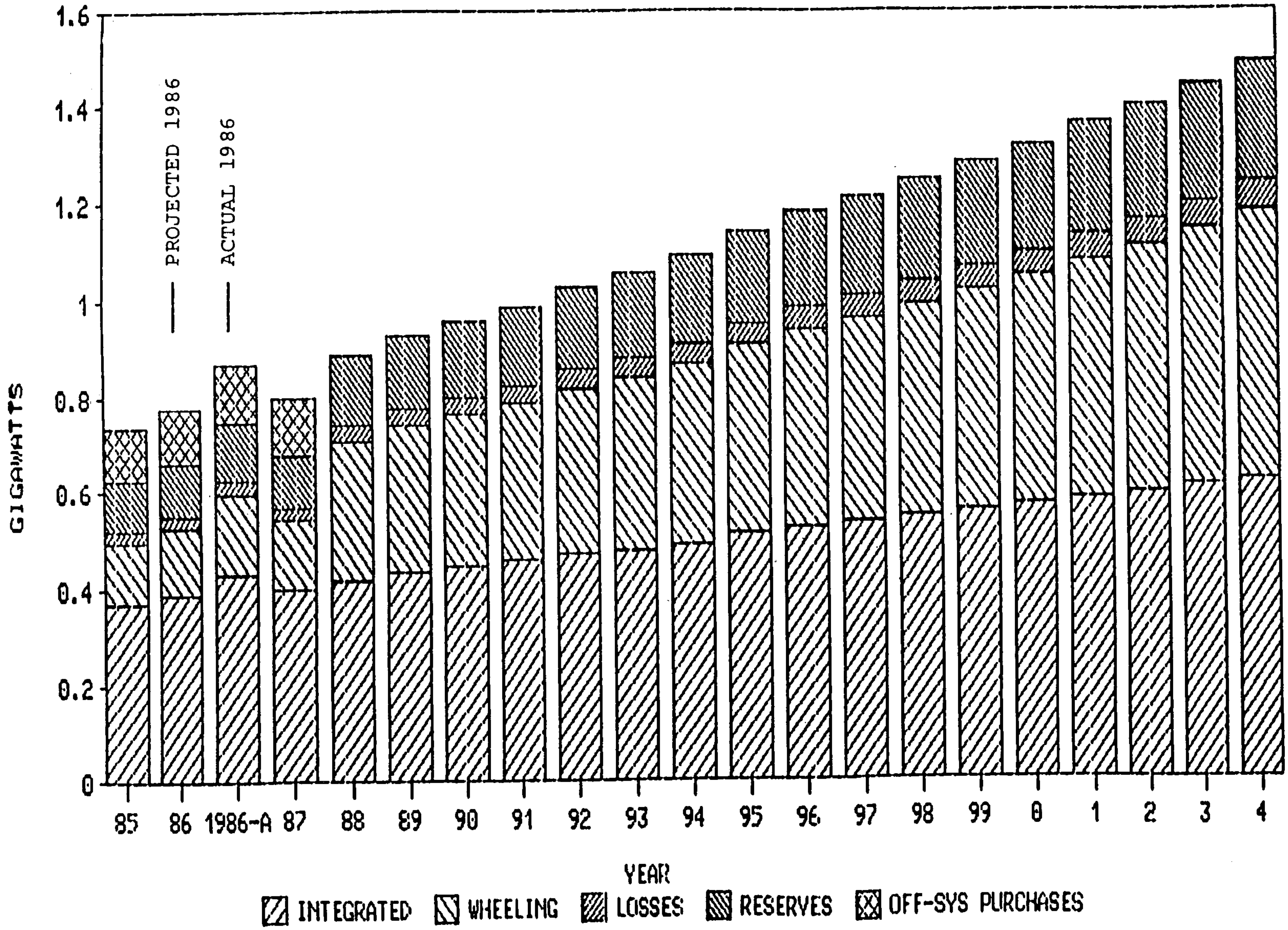

Figure 3.1-2. Actual Versus Projected Capacity Requirements (1986)

wheeling agreements with Alabama Power Company and Gulf Power Company; and the remaining 22% (off system) is served by purchases supplied from the transmission system of the companies. AEC terminated power purchase agreements with Alabama Power Company and Gulf Power Company, effective in June 1988, at which time AEC assumed generation and/or power purchase responsibility for the entire system load. Wheeling agreements remained in effect.

AEC-owned generation facilities, as shown in Table 3.2-1, include a combination of coal-fired steam units, hydro projects, and a combustion turbine. The Lowman plant is located on the Tombigbee Waterway near Jackson, Alabama. This station consists of three units and provides AEC's base-load generation. The McWilliams plant, located just north of Andalusia, Alabama, consists of three units. Units No. 1 and No. 2 were placed in service in 1954. Unit No. 3 was placed in service in 1959. Current plans include the repowering of units No. 1, No. 2, and No. 3 in 1993. The Gantt and Point "A" hydro projects are located on the Coneuch River, just north of Andalusia, Alabama. They were placed in service in 1924 and 1925, respectively. They have been well-maintained, upgraded, and refurbished through the years, and they are projected to remain as available units through the year 2000. These small units are operated primarily as peaking units when the water is available. During high-flow periods, these units may be operated around the clock and are sometimes required to spill water to maintain allowable pond levels. The Portland Combustion Turbine, located near DeFuniak Springs, Florida, was placed in service in 1964. It is operated to maintain reliability on Air Force load.

Table 3.2-1

AEC-Owned Generation Facilities

Unit	Capacity (MW)
Lowman #1	72.4
Lowman #2	231.8
Lowman #3	232.6
McWilliams #1	9.6
McWilliams #2	9.7
McWilliams #3	23.5
Gantt Hydro	3.0
Point "A" Hydro	5.2
Portland	9.9
Total	597.7

Southeastern Electric Power Administration (SEPA) is an agency of the Department of the Interior established to market electric power generated by the Corps of Engineers hydroelectric projects located in the Southeast. SEPA is authorized to sell power, with first priority given to municipalities and cooperatives. AEC purchases 154 MW of capacity from SEPA. In addition to SEPA purchases, AEC negotiated with neighboring utilities to purchase 150 MW of dependable capacity for a 10-year period beginning in 1988. In addition to this purchase of dependable capacity, smaller purchases of capacity were required to meet AEC's reserve requirements. These "deficit purchases" were strictly for reserves with little or no associated energy.

AEC has interconnection agreements with other utilities. These agreements are used to execute either short- or long-term power purchases and sales. They allow AEC to plan on small-capacity deficits with the ability to purchase capacity from other utilities on a short-term basis. As of 1988, AEC generation and purchase capability consisted of generation plants owned by AEC, allocation of SEPA power, and purchases from other utilities (see Table 3.2-2):

Table 3.2-2

AEC Generation and Purchase Capability

	MW
AEC-owned generation	597
SEPA purchases	91
Dependable purchases	150
Deficit purchases	45
Total capacity	883
SEPA wheeling purchases	63

Purchases from SEPA delivered directly to off-system substations are treated differently than other purchases. This is because AEC is not responsible for losses or reserve requirement for this purchase. In effect, the SEPA wheeling purchases (63 MW) decrease AEC's load, rather than increasing AEC's generation capacity. Figure 3.2-1 shows the location at that time of AEC's member systems, along with other details.

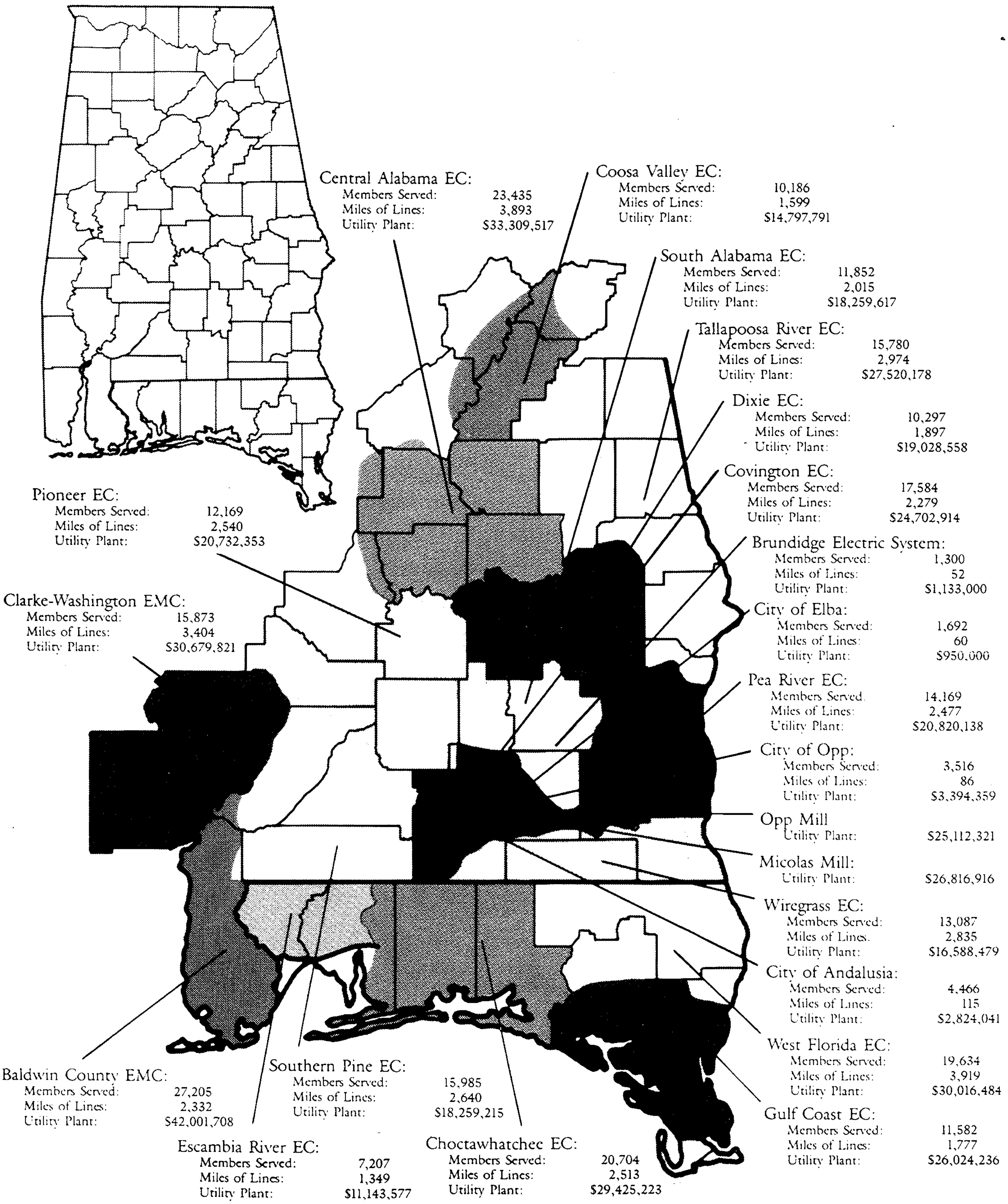

Figure 3.2-1. AEC Member Systems

3.3 Power-Supply Alternatives

AEC is committed to meeting the needs of its customers by providing dependable energy at the lowest possible cost. This not only means that AEC should have adequate generation capability (e.g., coal plants, hydro plants, purchase contracts) to meet its peak-load requirements, but sufficient reserve capacity should also be planned to cover reasonable contingencies. AEC is also accountable to its neighboring utilities to ensure that its generation and transmission system is reliable and does not cause undue burden on the surrounding systems' operations.

Utilities commonly express their reserve margin as a percent of their peak-load requirements. For many utilities, including AEC, it was understood at the time that 20% is a reasonable reserve level. This meant that AEC should have a generating "responsibility" equal to its forecast annual peak load, plus 20% extra. It was felt that this "reserve" was able to cover unforeseen outages of existing plants and could also act to dampen any forecast uncertainties. As shown by Table 3.3-1, it was forecast that by 1989 AEC would be significantly deficient in generating capacity.

In addition to AEC's commitment to its customers, AEC is also concerned about its impact on the electric reliability of the southeastern United States. AEC is a member of the Southern Subregion of the Southeastern Reliability Council (SERC). Each organization in SERC is responsible for planning its power-supply futures independently. The primary purpose of the SERC organizations is to promote the reliability and adequacy of electric power in the southeastern United States. Based on past experience, it was felt that reserve margins of 20 to 25% for the Southern Subregion offered a good target for expansion of bulk power facilities. Figure 3.3-1 shows that over a period of ten years, the Southern Subregion might, at times, be below this target, but for the most part it would be in excess of 20% reserve until 1995. This reserve margin assumes that all units planned by the reporting utilities, including AEC, are actually constructed. If this planned capacity is deferred or cancelled, serious capacity shortfalls could result. The Southwest Power Pool (SPP), which is the reliability area operating adjacent to the Southern Subregion of SERC, is expected to have a substantial capacity margin in the late 1980s and early 1990s; however, by the mid-to-late 1990s this excess may also be depleted. Opportunities for transactions with other members of SERC or utilities in SPP are limited to terms through the mid-1990s because of capacity shortages.

Table 3.3-1

AEC Responsibility/Capability Comparison

YEAR	LOAD	LD+RSV	CAPABILITY	EXC/DEF	ADD CAP	REMARKS
1987	568	681	688	7		
1988	735	883	838	-45	150	PURCHASE 150
1989	777	932	838	-94		
1990	801	961	838	-123		
1991	823	988	838	-150		
1992	854	1025	838	-187		
1993	884	1061	838	-223		
1994	914	1097	838	-259		
1995	955	1146	838	-308		
1996	984	1181	838	-343		
1997	1012	1215	838	-377		
1998	1042	1251	838	-413		

NOTE: DEFICITS MUST BE MET THROUGH CAPACITY ADDITIONS.

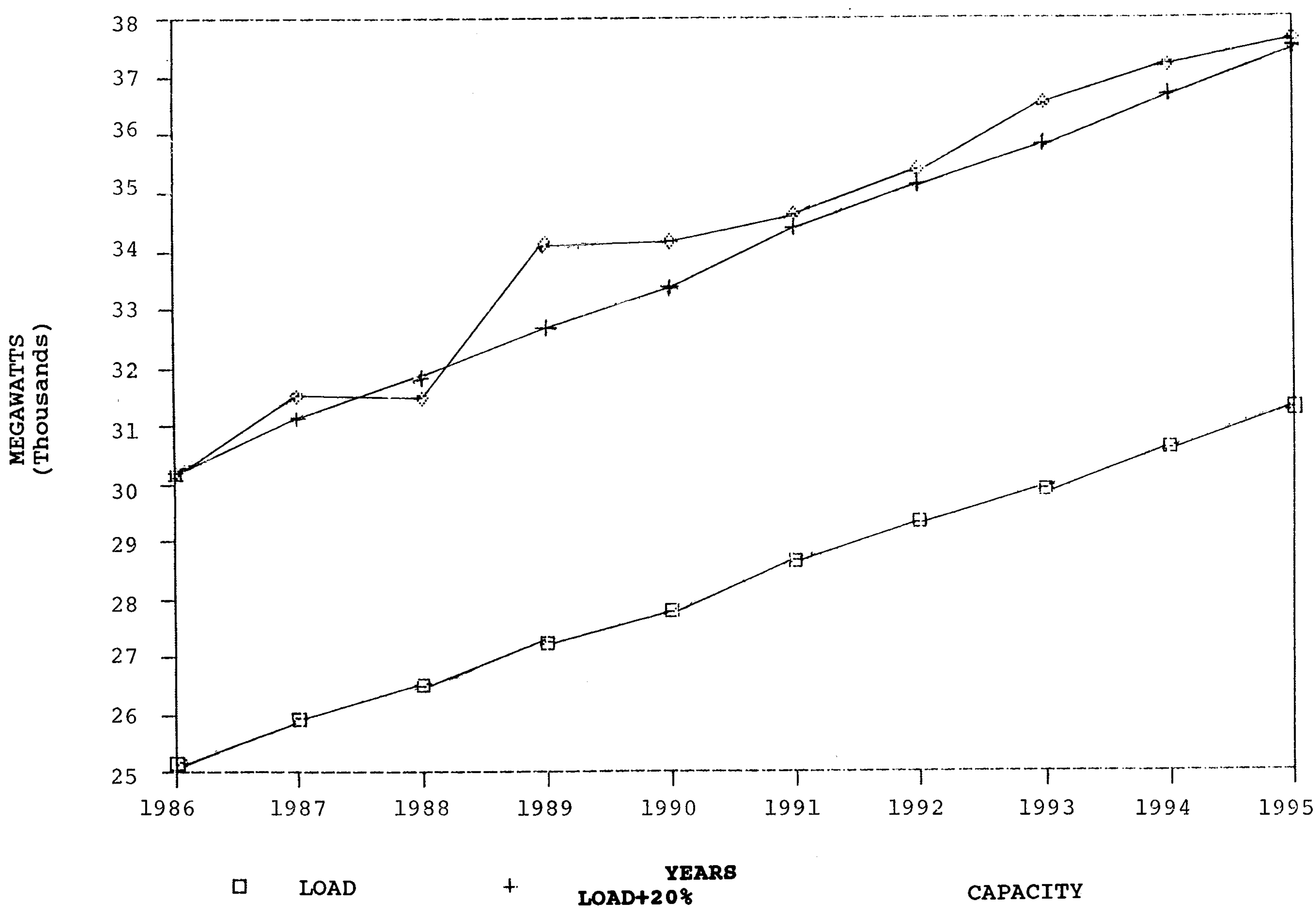

Figure 3.3-1. Southern Subregion Responsibility/Capability

Separate from its involvement with the reliability council, AEC maintains interchange agreements with other utilities in the area. These agreements allow the exchange of economy energy, short-term capacity, and replacement energy, and they also provide arrangements for transmission service. As previously addressed, AEC had capacity deficits by 1989, which required the addition of generating resources. Table 3.3-2 lists the wide array of alternatives which were available to AEC. In determining which of these resources was most applicable to the AEC system, consideration was given to expected operating procedures for existing and new capacity. These issues are addressed in Section 3.4, System Operating Policies.

Four different intermediate capacity types were evaluated for meeting AEC's 1989 capacity forecast (purchases, combined cycle, gas turbine, and compressed-air energy storage). An optimal unit size for the generating units was shown as 50 MW, which represents about two years of load growth on the AEC system. Periodic addition of small units did not significantly affect AEC's wholesale rate. A discussion follows of how each type applies to AEC's future capacity needs.

Purchases: Beginning in 1988, AEC began purchasing 150 MW of dependable capacity to serve projected member loads. This purchase is scheduled to run until 1998. Even with the 150-MW purchase and the addition of 50 MW of capacity in 1989, AEC was expected to have a capacity deficit of 43 MW which could be met through purchase of reserve capacity. This totals 193 MW of capacity purchases, or 25% of AEC's total system load which could be met by purchases in 1989.

According to the 1985 forecast, the consideration of using additional purchases to defer building permanent generating resources in 1989 required AEC to purchase 243 MW outside its system. This level of dependence on outside utilities was considered unacceptable. Of primary concern was that none of AEC's neighboring utilities had been willing to offer purchase contracts with terms longer than 10 years (through 1998). If no units were constructed by AEC, with all growth being met through purchases, by 1989 AEC would be purchasing approximately 560 MW of capacity. A large generation station would have to be constructed to replace the cancelled purchases, and consequently, rates would have to be raised an excessive amount to cover the required investment. AEC was already planning on having to replace the 150-MW purchases with a base-load unit. The burden of

Table 3.3-2

AEC Power-Supply Options (1985 Study)

1) Combustion Turbines (CT)

2) Compressed-Air Energy Storage (CAES)

3) Combined-Cycle Units

4) Hydro Units (Demopolis)

5) New Fossil Units
   A) Conventional Boilers
   B) Fluidized-Bed Boilers
   C) Bituminous Coal
   D) Lignite

6) McWilliams Station
   A) Retire
   B) Repowering
   C) Combined Cycle

7) Nuclear Units (Part of Farley)

8) Other Technologies

9) Purchases

10) Non-Generation Alternatives

having to replace an increment of 100 MW above this could cause significant rate shock to AEC's members.

Another risk would be in relying on the transmission networks of other utilities to wheel the purchases. AEC was already relying on other transmission systems for delivery of 193 MW; the addition of 100 MW was considered risky.

Therefore, in 1989, total reliance on the purchase options was removed from consideration as a viable alternative to meeting AEC's peaking and intermediate requirements. It should be noted that AEC reevaluates on a periodic basis (a common practice in the utility business) the economic benefits and disadvantages of increased or decreased purchases, as load forecasts and updated generation estimates change.

Combined cycle: Combined-cycle units use a conventional simple-cycle combustion gas turbine as the prime mover. The hot combustion gases are exhausted through a heat-recovery steam generator to produce steam which is used to drive a steam turbine to increase overall efficiency and produce additional power.

Combined-cycle units have much the same advantages and disadvantages of conventional combustion turbines. The efficiency is greater due to the heat-recovery feature, but the capital cost is greater for the same reason. Combined-cycle units have approximately the same capital cost as CAES units but lack the advantages of energy storage and reduction of premium fuel usage. Combined-cycle units were not further considered, since they would pose economic risk in future years, as premium fuel prices become more erratic.

Combustion turbine (CT): Combustion turbines have been used by electric utilities and other major industries for many years. Traditionally, utilities purchased them for peaking services, as their low capital cost, quick-start capabilities, but higher operating cost still made them sufficiently suitable for low-capacity-factor operations. In general, CTs would be used only during peak-load conditions or during emergencies. They could be used for limited load-following duty, but they are very inefficient for this mode of operation and become impractical to operate at less than 20 to 30% capacity levels.

Most CT utilize axial-flow compressors which compress outside air into a combustion area where fuel is burned. The hot gases from the burning fuel-air mixture drive the expansion turbine, which in turn rotates the compressor and generator, thus producing electrical energy for the utility grid. A CT typically burns premium liquid and gas fuels.

Compressed-air energy storage (CAES): Compressed-air energy storage power plants use some components similar to those in a CT, but arranged in a different manner. Unlike the conventional CT power plants, the compressor and expansion turbine are each connected to a motor/generator through a clutch (see Figure 3.3-2.). During off-peak periods the expansion-turbine clutch is disengaged, and the compressor clutch is engaged so that low-cost energy from the grid can be used to compress air into underground storage reservoirs. During periods of peak or intermediate electricity demand, the compressor clutch is disengaged, and the expansion-turbine clutch is engaged so that the compressed air is released, heated, and used to drive an expansion turbine. This saves a substantial amount in fuel costs, since approximately two-thirds of the power needed to run a conventional CT is used to compress the air before it goes to the combustor and expander. CAES units can thus be used for peaking service and also for load-following. Since the compressor idles while the expansion turbine produces power, all the power goes to the grid. This makes a CAES unit cost-attractive and have good part-load efficiency (compared to a CT).

3.4 System-Operating Policies

Generating capacity is typically broken down into three load types: base, intermediate, and peaking. Base-load generation has low operating cost with high capital costs and operates year-round at between 60 and 100% capacity factor. Intermediate generation capacity is utilized to serve frequently occurring (10 to 60% capacity factor) loads of short duration, and it typically involves capital and operational expenditures midway between base- and peak-load capacity. Peaking-generation capacity generally has high operational costs but has very low capital cost; consequently, this capacity is expected to operate less than 10% of the time.

By applying this operating strategy, e.g., to AEC's 1985 load-duration curve (Figure 3.4-1), it can be seen that the optimal mix of generating types for AEC should be about 50% base, 25% intermediate, and 25% peaking load. During 1986, AEC maintained a capacity mix of 78, 6, and 16%, respectively. It was thus evident that AEC's generation additions should first be of the intermediate type.

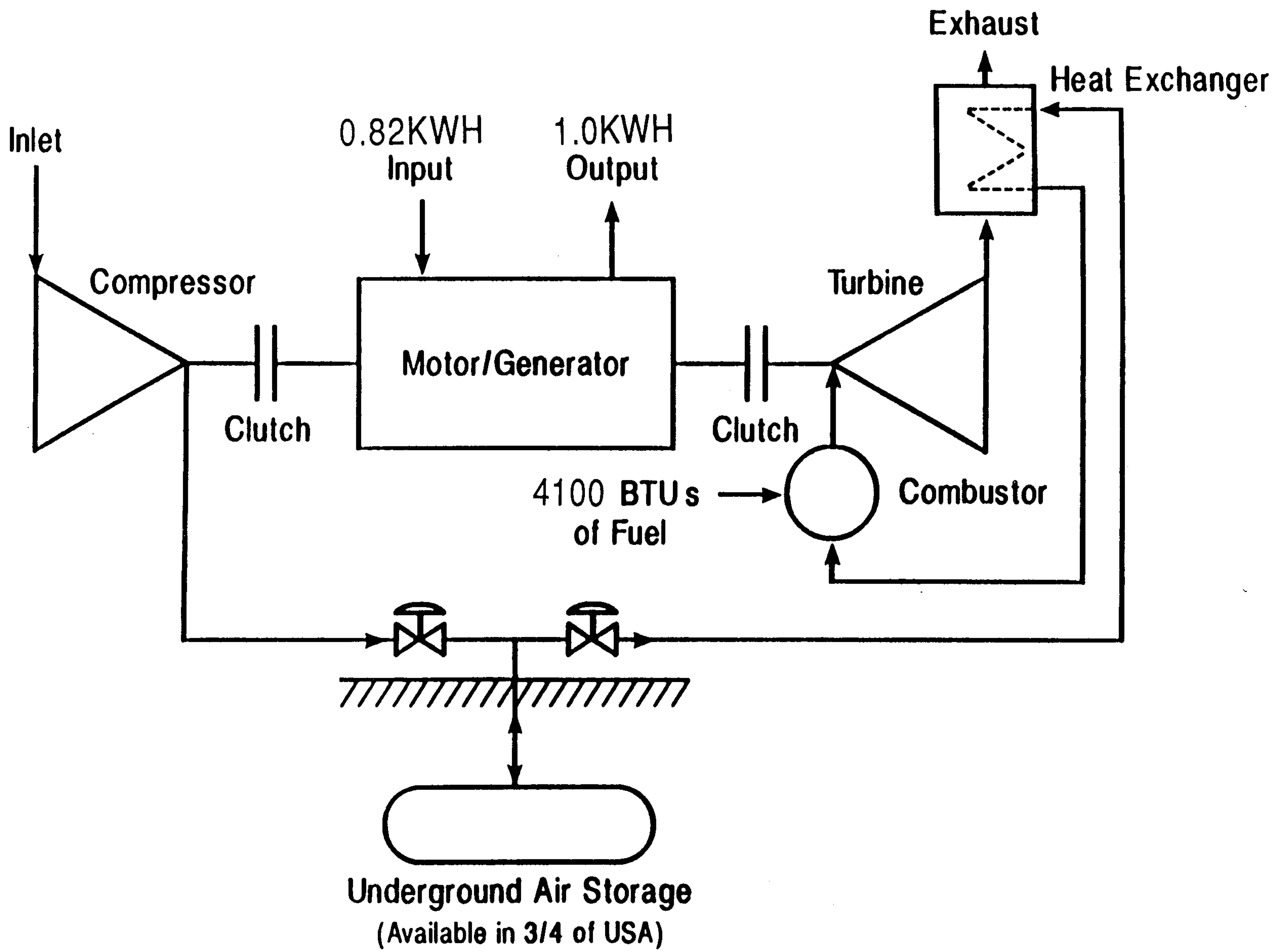

Figure 3.3-2. CAES-Plant Schematic

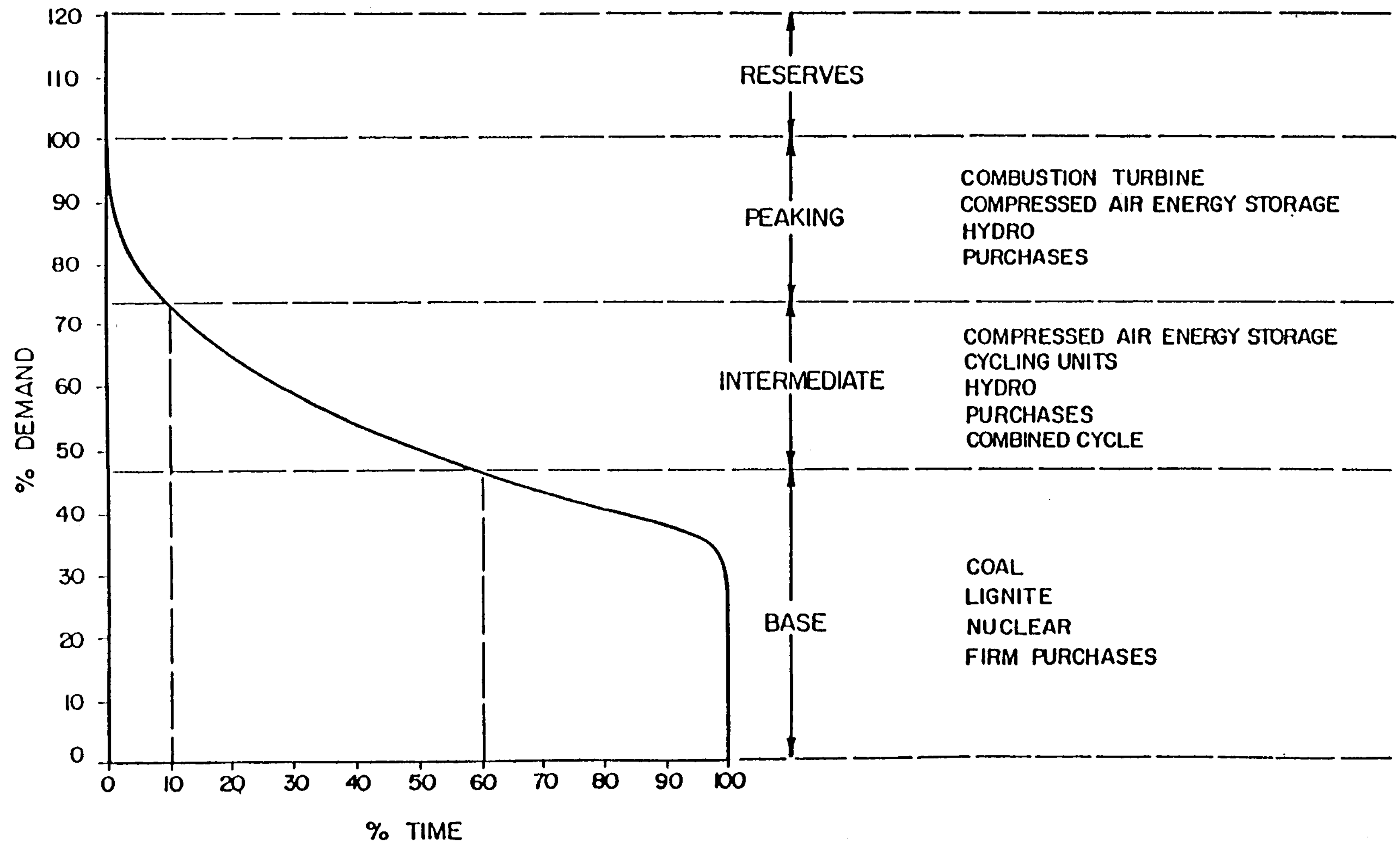

Figure 3.4-1. AEC Annual Load-Duration Curve

3.5 Cost Assumptions

The cost assumptions for the AEC CAES facility were based on extensive costing studies which were developed with the studies listed in Section 4.1.2 and the AEC use of the Powersym computer program.

3.6 Evaluation of Alternatives

The determination of which alternative addition of capacity was best suited to AEC's needs was based on the expected operating time of the addition. Figure 3.6-1 shows a comparison of annual cost for a gas turbine compared to a CAES plant. A cross-over point can be seen where the annual cost for a CAES plant would be lower than that of a combustion turbine (CT). When the operating time over the entire life of the 1989 unit was examined, it was clear that the CAES unit should be the preferred choice. Screening curves of this nature show the "economic window" for CAES and are useful for preliminary comparisons. AEC also performed detailed production costing studies for a projected 20-year period. These studies show CAES to be the most economical addition for the near term).

Other benefits of CAES include the opportunity for more efficient off-peak operations of AEC's existing coal units. Night-time generation from these units would be required to serve the system load plus provide energy for air compression at the CAES plant. Consequently, the units should be able to operate at higher, more efficient capacity levels.

Premium fuel prices may again become unstable. By installing a CAES plant instead of a CT, AEC could decrease its exposure to economic risk and should not be as severely impacted by possible rapid fuel-price escalations. A CAES unit uses about one-third of the premium fuel used by a CT. By installing a CAES plant, AEC could save money, while at the same time reducing its dependence on a limited natural resource. For a summary comparison of CT and CAES, see Table 3.6-1.

3.7 Initiation of AEC's CAES Project

The AEC CAES project was initiated with the AEC's Board of Directors action to issue a Letter of Intent (February, 1986) and the approval (July, 1986) for the engineer (Burns & McDonnell) to prepare the contract documents and issue same to contractors for bids.

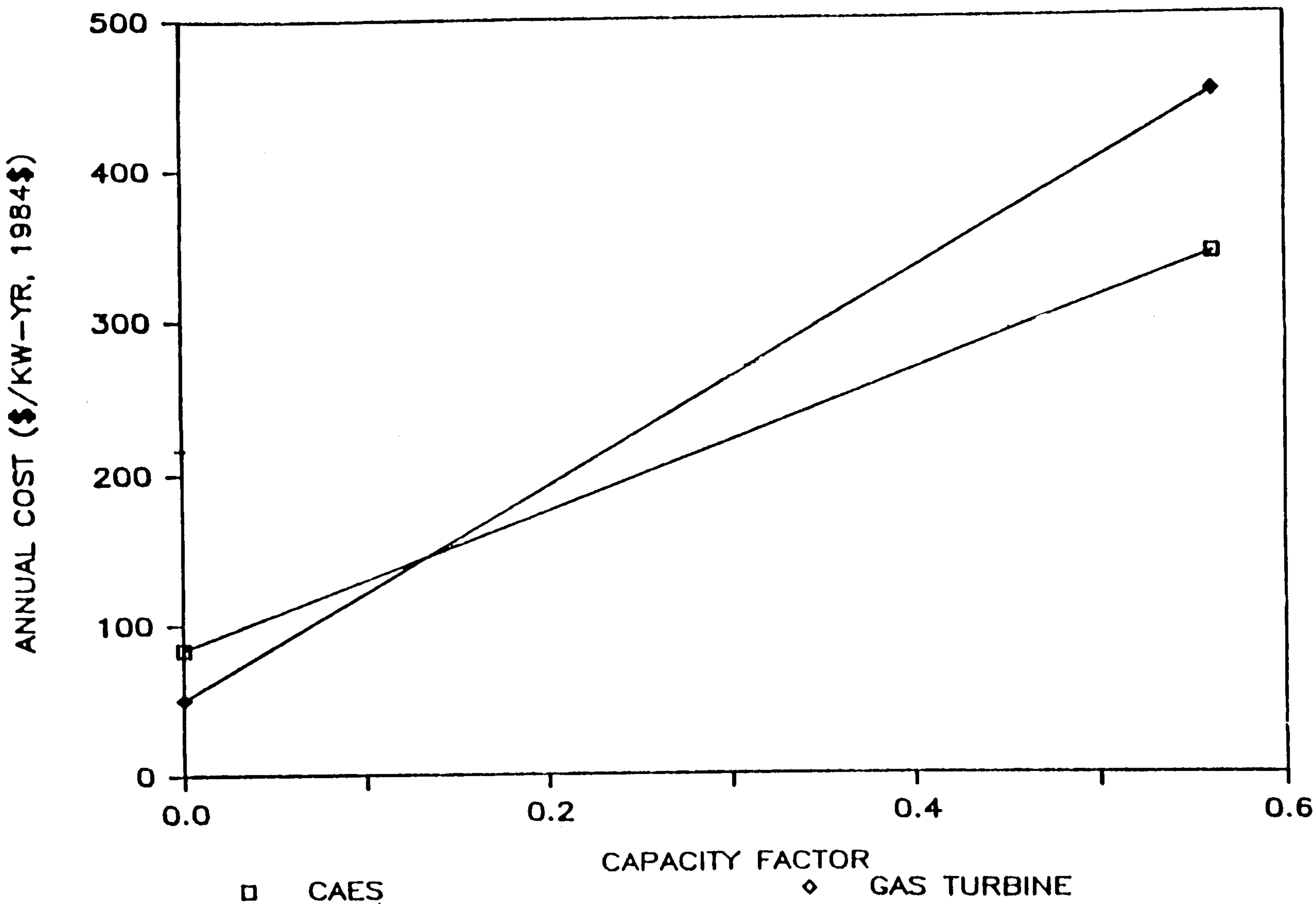

Figure 3.6-1. Screening-Curve Comparisons

Table 3.6-1

Generic Comparison of Combustion Turbine with CAES Plant

	Topic	Combustion Turbine	Compressed-Air Energy Storage
1.	Efficiency (Delivery)	26.2%	30.0%
2.	Operating Cost (if gas costs \$3.5/10^6 Btu, and electricity costs 20 mills/kWh)	45.5 mills/kWh	29.5 mills/kWh
3.	Capital Cost (1985 dollars, overnight construction)	450 \$/kW (100-MW plant)	500-600 \$/kW (25-220 MW plant) (10 hr store)
4.	Construction Time	1-1/2 yr	2-1/2 to 4-1/2 yr
5.	Part-Load Delivery Efficiency		
	- at 50% Load	21.3%	28.6%
	- at 20% Load	0	28.3%
6.	Hottest Blade Temperature	2100°F	1600°F
7.	Ramp Rate	15% per min	30% per min

Note: A combustion turbine is similar to a CAES plant whose clutches and storage valves are closed.

3.8 Project Financing

AEC studied the available money markets for financing, and it chose, because of the more favorable rates, to have the financing performed by Cooperative Financing Corporation (CFC). With the financing by CFC, a Type IIA lien was required by and was approved by the Rural Electrification Authority (REA).

Section 4

TECHNICAL DEVELOPMENT

4.1 Conceptual Design

4.1.1 Huntorf CAES Plant: The Northwestdeutsche Kraftwerk power system initiated the installation of the first CAES plant located at Huntorf, Federal Republic of Germany. The reality of this plant began with a feasibility study in 1969 and continued with order placement in 1973; construction began in 1974, was completed in 1977, and the facility became operational in 1978. The plant was designed to produce 290 MW, 50 hertz, and since beginning operation, it has demonstrated capability regarding full and partial load, spinning reserve, load leveling and following, synchronous condenser, and emergency black start; it does not have an exhaust-gas recuperator. The above-ground plant was built by Brown Boveri (BBC), and the cavern was developed by Kavernen Bau-Und Betriebs-GMBH (KBB) of Germany. The Huntorf plant operation for the first four years of operation (1980 thru 1984) had an accumulation of over 4000 starts, 93.7% availability, 98.8% starting reliability, 9.8% forced outage rate, and 0.51% unscheduled outage rate while operating unattended and remotely controlled from a site 80 miles away.

4.1.2 CAES studies: The following studies were available and utilized for the decision to construct the AEC CAES facility:

EPRI, 1977, "Conceptual Design for a Pilot/Demonstration Compressed Air Storage Facility Employing a Solution-Mined Cavern," EPRI, EM-391, prepared by General Electric Company for EPRI.

EPRI, 1982, "Preliminary Design Study of Compressed Air Energy Storage in a Salt Dome," EPRI, EM-2210, 9 volumes, prepared by United Engineers and Constructors, Inc. and Middle South Services, Inc. for the U.S. Department of Energy and EPRI.

EPRI, 1982, "Compressed Air Energy Storage Preliminary Design and Site Development Program in an Aquifer," EPRI, EM-2351, 9 volumes, prepared by Public Service Company of Indiana, Inc., Sargent & Lundy Engineers, and Westinghouse Electric Corporation for the U.S. Department of Energy and EPRI.

Gibbs & Hill, 1984, "Compressed Air Energy Storage (CAES) Consortium Presentation."

AEC, 1985, "1984 Power Requirements Study," prepared by the System Planning Department, Engineering and Operations Division, Alabama Electric Cooperative, Inc.

AEC, 1986, "1985 Power Supply Study," prepared by the System Planning Department, Engineering and Operations Division, Alabama Electric Cooperative, Inc.

EPRI, 1986, "Proceedings: Regional Conferences/Workshops on Small Compressed Air Energy Storage (Mini-CAES) Plants - A New Option," EPRI, EM-4445, prepared by Meeting Planning Associates, Menlo Park, California.

Gibbs & Hill, 1986, "Preliminary Engineering Study of a 50 MW Compressed Air Energy Storage (CAES) Electric Generating Station," prepared by Gibbs & Hill, Inc. and Fenix & Scisson, Inc. for Alabama Electric Cooperative, Inc.

4.1.3 Joint study - AEC and SMEPA: Alabama Electric Cooperative, Inc. (AEC) and South Mississippi Electric Power Association (SMEPA) engaged United Engineers & Constructors, Inc. (UE&C), to perform a joint economic feasibility study of a compressed-air energy storage (CAES) plant. The agreement for this study was accepted November 5, 1979. This study was predicated on independent operation of AEC and SMEPA systems, except for the projected CAES unit or units that would operate as follows:

1. Each 220-MW CAES unit would be jointly owned, with AEC and SMEPA owning 110 MW each.

2. Compression energy would be provided by lowest cost electricity available from either AEC or SMEPA.

3. One half of the CAES capacity, 110 MW, would be dispatched to meet individual load requirements of each utility.

The purpose of the study was to calculate CAES cost for the joint AEC/SMEPA systems under the above guidelines. The economics of introducing a CAES plant in the 1986-1995 time frame was examined and compared with the individual system expansion plans.

In 1979, AEC had installed generating capacity of 418 MW, and SMEPA, 573 MW. Both systems expected appreciable growth and had made two projections: a nominal 7% annual load growth, and a 5% annual-load growth. To meet these projections, each system had planned to install generating capacity for the 1980-1995 time period. By 1995, AEC was expected to have a total installed capacity of 2280 MW, and SMEPA, 1520 MW, for the 7% annual-load-growth case. For the 5% annual-load-growth case, AEC projected installed capacity of 1640 MW, and SMEPA, 1180 MW. For 7% annual-load growth, AEC planned to install four 370-MW coal-fired plants, while SMEPA planned to purchase an interest in four 105-MW coal-fired plants from Mississippi Power and Light and construct one 300-MW coal-fired plant. For 5% annual-load growth, AEC planned to install two 370-MW coal-fired plants and two 50-MW CT plants. For this growth case, SMEPA planned to purchase an interest in one 105-MW nuclear plant and three 105-MW coal-fired plants from Mississippi Power and Light.

After examining various CAES alternatives for the 1986-1995 period, an expansion plan utilizing CAES was selected which had a total installed capacity for AEC almost identical to their base expansion plan, while the expansion plan for SMEPA had a noticeably lower installed capacity during the 1986-1995 period for the 7% annual-load-growth case. The annual savings realized by the economic addition of CAES over the base-expansion plans are presented in Figures 4.1.3-1 and 4.1.3-2. For both of the load-growth cases studied, introduction of CAES into the AEC system was more economic than the base expansion plans.

For the period, 1986-1995, SMEPA would benefit from CAES only in the 7% annual-load-growth case. For the 5% annual-load-growth case, the base (reference) expansion plan proposed by SMEPA was more economic than adding CAES. This was because SMEPA did not need to construct a coal-fired plant during the study period; it could satisfy its load-growth requirement with low-cost, purchased, coal-fired power. This study was instrumental in SMEPA's decision to delete CAES from its expansion plans, thus removing the possibility of a joint CAES venture between AEC and SMEPA.

4.1.4 <u>50-MW plant</u>. With the availability of CAES plants in the 200-MW to 300-MW capacity, it appeared that a CAES unit modularized or skid-mounted with 25-MW and 50-MW capacities would be economically attractive, could help utilities meet intermediate and peak demand, have a short construction-lead time, and use proven components of U. S. and foreign design.

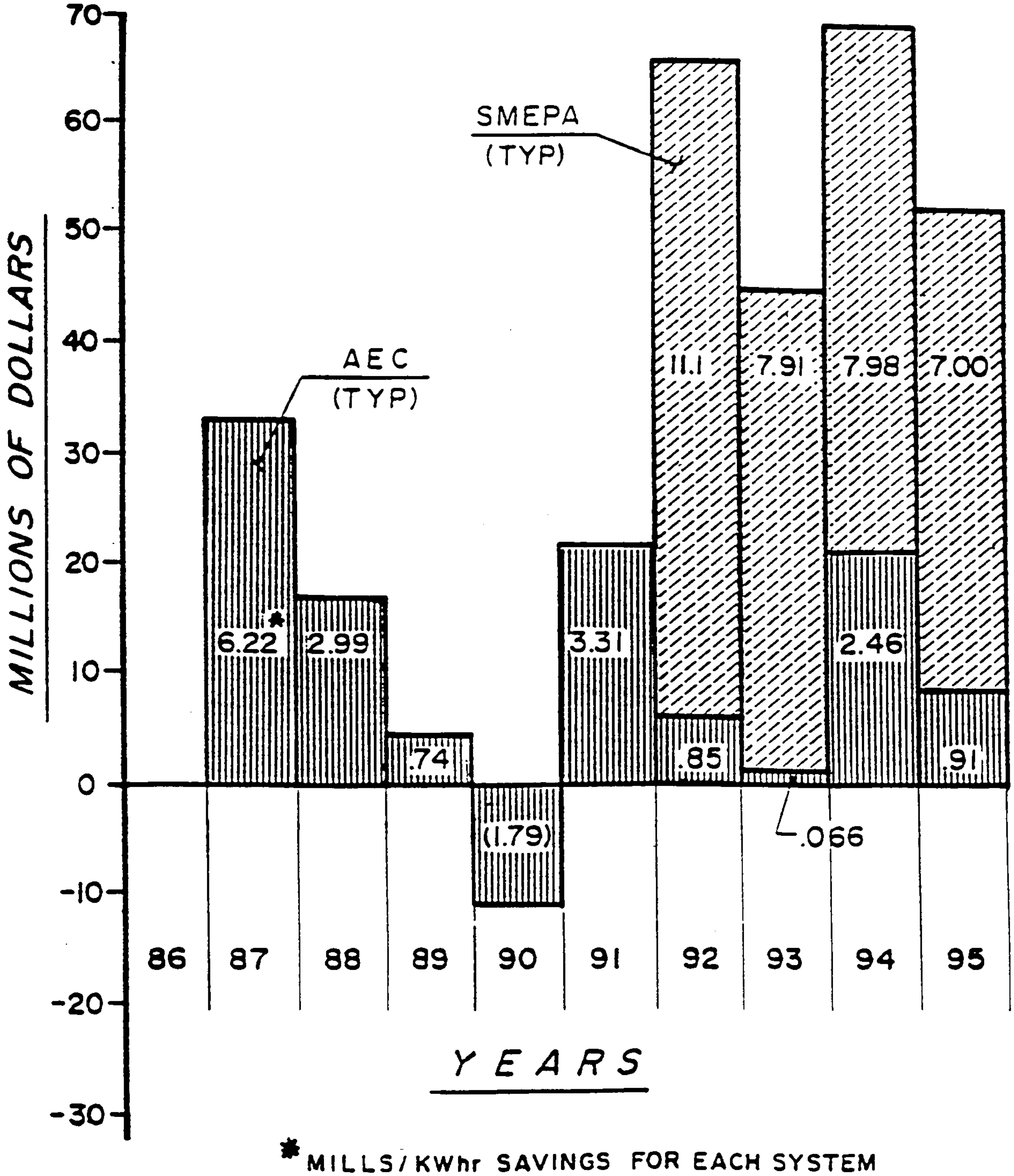

Figure 4.1.3-1. CAES Annual Savings (7% Load-Growth Case)

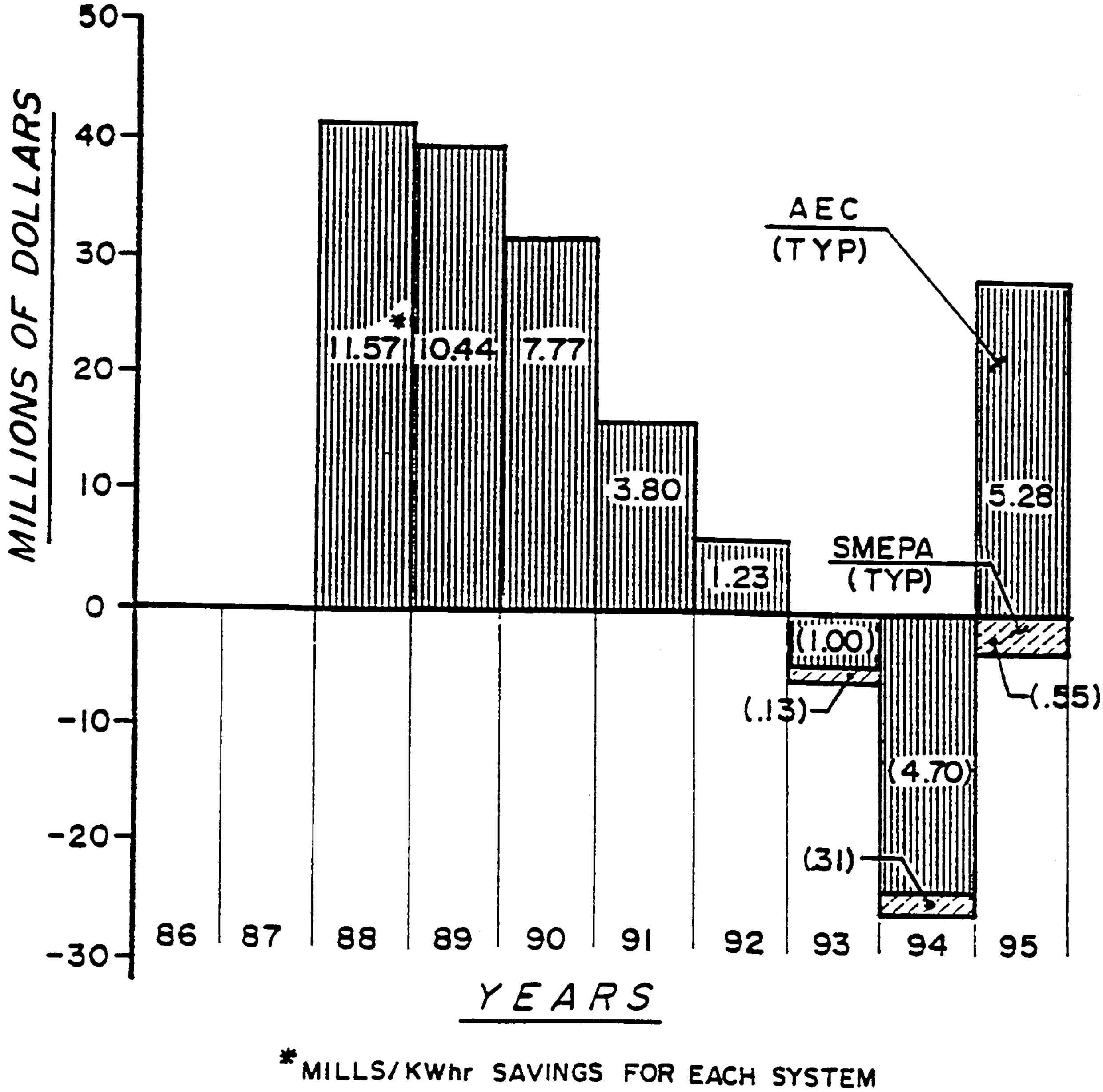

Figure 4.1.3-2. CAES Annual Savings (5% Load-Growth Case)

EPRI contracted Gibbs & Hill to conduct a study which resulted in the report, EM-3855, Analysis of Mini-Compressed-Air Energy Storage Plants, published in August, 1986. This report summarized the results of an engineering evaluation and optimization of mini-size (25 MW and 50 MW) turbomachinery trains for compressed-air energy storage (CAES) applications. A modular approach for turbomachinery development, utilizing only commercially available components with proven reliability, was adapted.

Six turbomachinery-train alternatives were developed and optimized for operation with each of the three types of underground structures: water-compensated hard-rock cavern, salt cavern, and aquifer reservoir. Turbomachinery trains were based on technical proposals received from qualified manufacturers for all six turbomachinery-train alternatives. Each proposal had a budget price, performance statement, and required technical descriptions.

To evaluate installed costs, economics, construction schedules, and land requirements, plans were developed for 25-MW, 50-MW, and 100-MW (two 50-MW units) CAES plants, and major systems and equipment were identified and sized. Also presented in the report were the results of the following studies:

1. Underground-storage cost estimate and analysis, with recommended equations and procedures for installed cost of the three geologic types of underground storage.

2. Comparative analysis of constant pressure vs. sliding-pressure turboexpander operation, as related to overall plant economics for best integrated above- and below-ground equipment and systems.

3. Sensitivity analysis of various plant and cavern configurations which developed penalty factors applied to variances in cavern depth, limitations in maximum stored air pressure and temperature, and distance between plant and underground storage.

This report was utilized as a beginning for AEC to have preliminary drawings, specifications, and bid documents prepared for a 50-MW CAES plant. These documents were supplied to bidders to submit their proposals for the design, furnishing, delivery, construction, and erection of equipment and material at the AEC McIntosh CAES power-plant site of one or two 50-MW compressed-air energy storage (CAES) generating units for AEC, with the receipt date of the bids as July 14, 1987.

4.1.5 110-MW plant: Based on the information contained in the bids for the one or two 50-MW CAES units, it became evident that the installed equipment cost-per-kilowatt capacity was higher than expected. It was discovered that equipment suppliers of the turbomachinery trains could use the same expander-frame size for 50- or 100-MW units. This gave credence to the possibility that a 100-MW unit would possibly have an attractive installed-equipment cost-per-kilowatt capacity. AEC revised and reassembled the bid package, and a revised proposal for a 100-MW skid-mounted unit (with an option for a second unit) was released for bid. The four responding bidders were Becon Construction Co./Bechtel Corp.; Gibbs and Hill, Inc./Harbert International, Inc.; Tippett & Gee, Inc./Comstock, Inc.; and Yeargin, Inc./United Engineers and Constructors, Inc.

The receipt of the bids for the 100-MW CAES plant did have an economical installed-equipment cost-per-kilowatt capacity, and bidders offered a unit capable of 110 MW net at the station bus. The bids were evaluated, and the selection was made, favoring the low-cost 110-MW offering of the Joint Venture (JV), Gibbs and Hill, Inc./Harbert International, Inc.

4.2 AEC CAES-Plant Design Criteria

4.2.1 System: The CAES plant site would potentially have a two-unit configuration. Each unit would be rated at 110 MW - 26 hr and provide intermediate- and peaking-power load service to the AEC electrical system, which is supplied from several generating facilities and is interconnected with other utilities. The first unit, with one cavern, would be built in 1988-1991. The second unit would be a possible future unit, with the second cavern.

The plant would be designed to operate satisfactorily under rapid-load changes and maintain stable load control when operating in parallel with the electric system, independently during a blackout, or in parallel with future CAES units. It should be suitable for remote-controlled, unattended operation at all loads and modes using signals transmitted and received over AEC's microwave system.

Expected average generating conditions for the first 10-year period are given in Table 4.2.1-1. The times do not include periodic testing for assuring maximum starting and loading capability.

Table 4.2.1-1

Average Generating Conditions

Hours operation per year	Load (MW)
100	20
400	40
700	60
400	80
100	100

The plant would be designed to operate under the full range of ambient conditions in all modes required to coordinate with AEC's interconnected electrical system. In general, the normal steady-state modes would be:

a) Cold standby: During spring and fall, when need for the plant is not anticipated, it is placed in cold standby. In this mode the plant consumes minimum amount of standby energy.

b) Hot standby: When motor/generator main windings are not energized, the unit goes into the hot-standby mode ready to go into operating mode in minimum time. This mode is required in summer and winter when intermediate and peak loads are anticipated.

c) Compresssion mode: On remote fuel selection and command, the compression train, together with motor/generator, is brought up to synchronous speed using the expansion turbine. After automatic synchronization, the expander drive is declutched so that the motor/generator drives only compressors to charge the cavern. The mode ceases on commands or automatically upon reaching a preselected cavern pressure or the maximum cavern-operating pressure.

d) Generation mode: On fuel selection and command for normal start, compressors (if running) are shut-down. After compressors are automatically declutched, locked-out,and picked-up at low speed by the turning gear, the motor/generator may then be brought up to synchronous speed using the expansion turbine, synchronized, loaded to preselected or minimum load, and subsequently, on command, loaded to set value or operated in load-following manner. During this mode, the compressor train remains in the hot-standby mode. If the unit receives a signal for emergency start in lieu of normal starting signal, the unit is automatically loaded to preselected or maximum output mode at increased ramp rate so that the unit can supply 110 MW net to the substation bus in less than nine minutes.

e) Synchronous condenser: On remote fuel selection and command, the motor/generator is brought up to synchronous speed using the expansion turbine. After automatic synchronization, the drives are declutched, and motor/generator excitation is controlled by automatic voltage regulator or remotely controlled. The compressor train remains locked-out in hot-standby mode.

f) Transient modes: Between normal steady-state modes, the plant is designed for automatic sequencing of equipment and events to safely warm-up, start, stop, and cool-down equipment, as required between modes of operation selected by the operator. Under these conditions, the turning gears operate for the required period of time.

g) Black start: The plant, controls, and equipment are designed to operate automatically by remote supervisory control under black-starting conditions, i.e., without outside power for start-up from plant substation. Under these conditions, the plant is capable of start-up with electric power from emergency diesel generator and is synchronized with the emergency diesel-generator set, but not with de-energized electrical grid. When the unit substation breaker is closed under remote manual supervisory control, the unit is simultaneously able to pick up applied load with momentary dip in frequency of 2.0 Hertz or less.

h) Simultaneous operation of compressors and expanders: The plant, controls, and equipment are designed to operate automatically by remote supervisory control with simultaneous operation of generator and compressors. Under this simultaneous compression/generation mode, the unit is required to change from compression mode to generation mode without stopping the unit, disconnecting electrical supply to motor/generator, or uncoupling compression train. On signal, the expansion turbine starts, accelerates to synchronous speed, and is clutched to drive the motor/generator and compressors. Compressors and valves are controlled so that they use minimum amount of power. The expansion turbine in steady-state operation is not required to drive the motor/generator and simultaneously drive the compressor train in compression mode.

Operating cycles:

A. Weekly cycle: Cavern has adequate compressed-air storage (minimum net usable cavern is 19 million cubic feet), and turbomachinery train has adequate capacity, so that the plant can be operated as follows (see Figure 4.2.1-1):

1. Day 1 through 5: Generation mode 10 hours per day at load of 100 MW net, producing 1000 MW-hrs at substation bus each day.

2. Day 1 through 5: Compression mode 10 hours per day.

3. Day 6 and 7: Compression mode for total of about 30 hours, bringing cavern pressure back to that required to start weekly cycle over again.

B. Continous generation: Cavern has adequate compressed-air storage, and turbomachinery train has adequate capacity, so that plant can be operated as follows:

1. Starting at cavern maximum operating pressure, in compression mode for 26 consecutive hours at 100 MW net, producing 2600 MW-hrs at substation bus.

2. Starting at minimum cavern operating pressure, in compression mode for about 39 consecutive hours to return cavern to maximum operating pressure.

C. Daily cycle: Cavern has adequate compressed-air storage, and turbomachinery train has adequate capacity, so that plant can be operated as follows:

1. Generation mode for 10 hours, at load of 100 MW net and producing 1000 MW-hrs at substation bus.

2. Compression mode for 16 hours or less, at which time cavern pressure equals pressure at the start of generation mode.

Weekly Operating Cycle The large cavern of Alabama Electric Cooperative's CAES plant will allow the utility to take advantage of inexpensive electricity to compress air on week-nights and over the weekend. In a typical week of operation, the plant will start with a fully charged cavern. It will generate about 10 hours per day and be partially recharged each week-night, as depicted in this sawtooth curve. On Saturday and Sunday nights, when electricity is least expensive, the cavern will be brought back to its full charge.

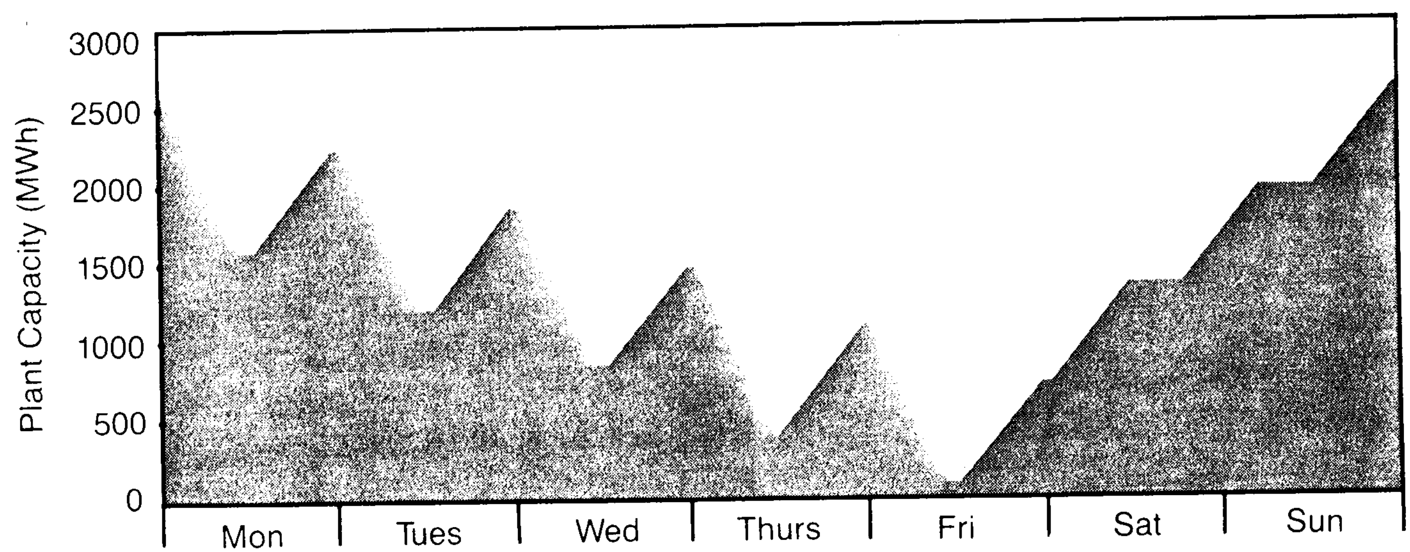

Figure 4.2.1-1. AEC CAES Weekly Operating Cycle

The plant is expected to run at the above conditions with minimal downtime for inspections and maintenance. It should comply with all emission requirements in all modes.

Design parameters: The equipment is designed and manufactured for the application without overstressing any components under the specified operating conditions for this application. During the operation under any of the above modes or in the transition between modes, the equipment and controls should ensure that the allowable velocity and temperatures in the motive air piping, particularly in the well casing, are not exceeded. The plant design and control system under normal operation does not allow the cavern to decrease below the minimum pressure against which the compressor train can refill the cavern without special procedures.

Plant-performance guarantee: The plant operates without damage, throughout the entire range of site conditions and operating parameters. The performance values tabulated are in part calculated, based on assumed cavern temperatures, thermodynamics of compressed air, cavern volume, and cycle of operation, including the following:

a) Average cavern wall temperature, 95°F.

b) Average compressed-air temperature at start of the generation cycle, 95°F.

c) Cavern volume, 19,000,000 cubic feet.

d) Cycle of operation: 26 hours of generation at 100 MW net, transition to compression mode, and 41 hours or less of compression as required to replace mass of air removed from cavern during generation.

e) During recharging of cavern, from minimum to maximum pressure, the temperature of stored air increases about 33°F, to 128°F.

f) Difference in air pressure in air-conductor pipe (measured at well-head) and the cavern (measured at well-head gauge connected to annulus space between last cemented casing and air-conductor pipe) is expected to be less than 30 psig when .lh8 generating 100 MW net.

g) Atmospheric pressure, standard for 50 feet above mean sea level.

The plant and individual systems and equipment should perform as described below when tested in the field.

Generation mode: The maximum continuous guaranteed rating, as measured at the CAES-plant substation bus when operating at the design-site conditions at a power factor of 0.85 to 1.00, should be 110,000 kW with the recuperator in service.

As determined at the CAES-plant substation bus at a power factor of 0.85 to 1.00, the plant should generate 100 MW net continuously for at least 26 hours when starting with a fully charged cavern and ending with the cavern at minimum operating pressures, using either natural gas (primarily fuel) or No. 2 fuel oil (secondary fuel), and with the recuperator on-line.

When operating at the design-site conditions and operating parameters, the plant heat rate on a higher-heating-value (HHV) basis, based on the net output per unit, should not exceed the values shown in Table 4.2.1-2, with the recuperator having a rated effectiveness of 0.75 and an inlet air temperature, after the pressure-reducing valve, of 95°F.

When the units, operating at any load, are tested in compliance with the conditions of the Owner's Permit from the Alabama Department of Environmental Management, Air Division, the maximum emissions should not exceed those shown in Table 4.2.1-3, with and without water injection (emissions measured simultaneously). The exhaust from the unit, while burning the specified fuels without additives, should appear as a "clean stack," and smoke level should not exceed 20% opacity. Water injection should not be required (to meet emission standards) with the first unit, but provision is made for this feature on the first unit.

Compression mode: When operating at the design-site conditions, the compressor train is required to meet the following guarantees:

1. Be able, in the connected cavern, to compress air from minimum to maximum cavern-air operating pressures at any site ambient air temperature. Motor rating should have minimum power margin of 5%.

2. Be able to bring pressure in cavern from minimum operating pressure (reached after running at 100-MW net generation mode for continuous 26 hours with 19,000,000 cubic-foot cavern) to maximum operating pressure in 41 hours or less, using no more than 2,083.9 MWh of total energy consumption when running at design-site conditions.

Table 4.2.1-2

Net Heat Rate (HHV) (Btu/kW-hr)*

Net Load (MW)	Gas	No. 2 Fuel Oil
110	4568	4353
100	4585	4358
75	4697	4448
50	4753	4530
25	5253	4870
10	6115	5622

*To convert the heat-rate design values to lower heating value (LHV), which is the normal convention for a CT, the "gas" values are divided by 1.1, and the "oil" values are divided by 1.065.

Table 4.2.1-3

Maximum Emissions (110 MW Net)

	Gas	No. 2 Fuel Oil	Gas	No. 2 Fuel Oil
Water Injection (lb/hr)	none	none	12248	12924
Nitrogen Oxides (lb/MWh)	2.3	3.3	1.15	1.65
Carbon Monoxide (lb/MWh)	0.33	0.33	0.49	0.49
Hydrocarbons (lb/MWh)	0.016	0.016	0.032	0.032

3. Starting from a fully charged cavern, and after running continuously in the generation mode for 10 hours on natural gas, the required energy to recharge the cavern to maximum operating pressure should not exceed the values given in Table 4.2.1-4.

Table 4.2.1-4

Charging Energy Required

Load (MW)	Generated (MWh)	26-hour Cavern (MWh)	Charging Ratio
110	1100	899.4	0.817
100	1000	833.4	0.833
75	750	671.9	0.896
50	500	499.9	1.000
25	250	334.8	1.339
10	100 (Min Stable)	213.6	2.136

4. When cavern is at minimum operating pressure, the expander should be able to bring compressor train to synchronous speed, synchronize motor, and start compression cycle at least five times. (At minimum pressure, the cavern should have enough reserve air for five starts.)

5. Maximum operating pressure and temperature under any operating conditions should not exceed 1140 psia, 130°F, under full-load conditions, at compressor discharge, downstream of aftercooler.

6. Compressor train should be capable of stable operation on performance curves supplied by bidder between: flow range, 137 to 208 lb/sec (dry); pressure range, 462 to 1200 psia, measured at aftercooler outlet.

7. When compressor train is operated at inlet air conditions shown on Dresser-Rand curves, and intercoolers are supplied with 79°F cooling water at flow of 197 lb/sec (dry), and final discharge pressure of 909 psia at high pressure compressor discharge, the power consumed, measured at motor shaft, should not exceed 48.925 MW.

Motor/generator

1. Maximum generator capability at 13,800 volts, 85% power factor, when ambient air and temperature rises are in accordance with ANSI Standard C50, should be 111.55 MW.
2. Motor/generator capacity as motor should be 72,360 bhp, without exceeding allowed winding temperatures.
3. Maximum continuous capability of motor/generator as synchronous condenser should be 110,000 kVAR when operating under following conditions:
    a. Site conditions.
    b. When operating declutched from balance of turbomachinery train.
    c. Temperature of stator windings equal to or less than allowed temperatures for Class F insulation provided, or 130°C.
    d. Temperature of armature equal to or less than allowed temperature for Class F insulation provided, or 145°C.
    e. When supplied with 1,500 gpm of cooling water.
    f. When supplied with 2,378 kW of electrical power to drive the unit.

Hot-standby mode: Under hot-standby mode, the unit should not use more than an average of 200 kWh/hr (four-hour average with unit operating 10 hours/day), and maximum demand should not exceed 230 kW.

Cold-standby mode: The unit under cold-standby mode should not use more than 25 kWh/hr, and maximum demand should not exceed 40 kW.

Black-start mode: Under black-start mode, the dead-load pick-up capability should be at least 10,000 kW.

Transition between modes:

1. Transition into generation mode: Time from initation of signal by operator to go from:
    a. Cold standby to hot standby, not to exceed 12 hrs.
    b. Hot standby to generator synchronized, not to exceed 5 min.
    c. Generator synchronized to full load (emergency start), not to exceed 4 min.

d. Generator synchronized to full load (normal start), not to exceed 8 min.

e. From compression mode to synchronized generation mode, not to exceed 24 min.

2. Transition into compression mode: Time for initiation of signal by operator to go from:

a. Hot standby to motor synchronized, not to exceed 8 min.

b. Motor synchronized to full air flow to cavern (blow-off valves closed), not to exceed 4 min.

c. Generating mode to blow-off valves closed for compression, not to exceed 75 min.

d. Synchronous condensing mode to blow-off valves closed for compression, not to exceed 75 min.

Well/cavern:

1. Volume of cavern should be at least 19,000,000 cubic feet.

2. Final cemented casing string for cavern should be stable and safely withstand pressure of 1190 psig at casing shoe. During cavern-integrity test, nitrogen pressure at the well-head should be 1190 psig, less the column of nitrogen above casing shoe.

3. Rate of air loss from cavern, well, and wellhead, should not exceed 5.0 psig/day during cavern-integrity test, which should be conducted when cavern is filled with brine in accord with approved procedures.

4. Cavern safety valve during initial charge should be set to relieve excess air from cavern whenever pressure exceeds 1130 psig at well-head. (Not applicable if compressor train is used for charging.)

5. Maximum temperature of air injected into the wellhead should not exceed 150°F.

6. Cavern pressures measured at well-head:

a. Cavern design pressure 1130 psig and temperature 150°F. (Pressure which cavern and casing can safely withstand.)

b. Cavern minimum design pressure 0 psig (atmospheric) and temperature 40°F. (Minimum safe pressure determined from rock mechanics.)

c. Before start of continuous generation, cavern maximum operating pressure 1054 psig (no flow). Pressure at which compressor train automatically shuts down should be 1060 psig, fully charged cavern, based on assumed conditions with air flowing. Pressures are measured at the well-head.

d. Cavern minimum operating pressure at end of continuous generation should be 650 psig. (Pressure based on assumed conditions at which expanders automatically stopped and generator tripped when operating in generation mode. Pressure should permit starting of unit in compression mode at least five times.)

e. It is anticipated that pressure in motive air line increases to about 680 psig when flow of air stops. At start of recompression it is anticipated that pressure increases to about 705 psig at wellhead after flow of air into cavern commences due to pipe friction flow losses.

7. Minimum cavern air temperature measured at the wellhead during generation mode at 100 MW net should be 40°F based on assumed conditions.

<u>Cavern during generation</u>: During generation at 100 MW net, the maximum difference between the actual pressure measured in the annulus between the last cemented casing and the air-conductor pipe at the well-head and the well-head pressure in the air-conductor pipe should not exceed 30 psig.

<u>Recuperator</u>: It is used to transfer heat from the exhaust gas to the incoming compressed air, thus achieving a considerable savings in fuel. The recuperator for the AEC CAES plant is based on research done by EPRI and is a unique design which employs four heat-exchanger sections, one which is cocurrent flow, and three which are countercurrent flow. The purpose of the concurrent/countercurrent flow is to reduce corrosion by maintaining the tubes at a temperature higher than sulfuric acid dew point, thus eliminating the acid corrosion which is associated with fuels containing sulfur (e.g., oil).

The EPRI research covered all facets of recuperators: types, effectiveness, materials, geometry, construction details, thermal stresses, service life, vibration, and cost. These studies also produced the requirements for a procurement specification, equipment specification, and guidelines for evaluating the equipment specification:

1. When operating under conditions set forth in the contract, and with 95°F inlet air temperature, the recuperator should be guaranteed to have performance shown in Table 4.2.1-5. Effectiveness is the ratio of temperature difference between air out and air into the recuperator, divided by the difference between expansion-turbine exhaust-gas temperature and air temperature into the recuperator. Expected air-pressure losses and exhaust-gas pressure losses are shown in Table 4.2.1-6.

2. Recuperator should be guaranteed to have a minimum operating life of 34,000 hours. Based on firing the specified fuel oil for 1700 hours per year, expected corrosion rates of recuperator tubes and casing are expected to be negligible.

Combustion chambers: The high-pressure and low-pressure combustion chambers should achieve a combustion efficiency (the ideal fuel-air ratio divided by the actual fuel-air ratio) of at least 99.9% at full load, with the level of water injection (if any) required to meet NO_X emissions standards, and with a maximum CO content in the flue gas of less than 50 ppm.

Cooling tower: It should be purchased on guarantee from the manufacturer, with data and values submitted as compliance submittal becoming the contractor's guaranteed performance values. At the operating conditions, the tower should have 5°F approach in the generation mode and 8°F approach in the compression mode.

Natural-gas compressors: They should operate at the following conditions:

1. Gas composition as in contract.
2. Inlet pressure, 200 psig at substation.
3. Inlet temperature, 65°F.
4. All ambient conditions, as in contract.

Each of the two required natural-gas compressors should be guaranteed, as shown in Table 4.2.1-7.

Table 4.2.1-5

Recuperator Performance (with 95°F Inlet Air from Cavern)

Generator Load (MW)	Effectiveness (%)	Air Side Flow (lb/hr)	Air Side T (Out) (°F)	Exhaust Side Flow (lb/hr)	Exhaust Side T (In/Out) (°F)
110	75.0	1,225,476	546.6	1,246,968	697/273
100	75.6	1,133,568	563.9	1,153,116	715/276
75	76.1	900,792	609.5	915,480	771/287
50	78.0	682,344	645.0	691,884	800/282
25	79.0	452,340	563.0	456,984	800/277
10	81.1	286,920	667.0	287,100	800/258

Table 4.2.1-6

Pressure Losses

Load (MW)	Pressure Drop Air Side (psi)	Pressure Drop Exhaust (Inches, Water)	Min. Tube Temp. (°F)
110	19	10	259
100	16.4	9	260
75	10.8	6.6	268
50	6.2	4	278
25	2.8	2	266
10	1.2	1.9	256

Table 4.2.1-7

Compressor Guarantees

	Stage 1	Stage 2	Combined
Minimum rated capacity (scfm)	4,957	1,561	--
Discharge pressure (psig)	271	856	--
Discharge temperature (°F)	106	268	--
Maximum rated power (hp)	--	--	310
Motor input (kW)	--	--	250

Pumps: Pumps should be purchased for motors equal or greater than 50 horsepower, with "wire-to-water" performance guarantees. Pump curves and pump data should be submitted as compliance submittals, and the approved submittals should become the guaranteed performance values.

Transformers: The specifications for the transformers in the cooling mode are given in Table 4.2.1-8.

Table 4.2.1-8

Transformer Cooling-Mode Specifications

	Generator step-up (OA/FOA)	Station service (AA/FA)
Continuous capacity and maximum temperature rise: (MVA) (°C)	100/133 (65°C)	1.5/2.0 (115°C)
Efficiency vs. load in % of 65°C rating:		
010	99.6	--
100	99.7	--
75	99.7	--
25	99.7	--
No load and 100% rated voltage:		
Excitation current (% of full load)	0.5	--
Losses (kW)	75	6.0

4.2.2 Cavern: The equipment and materials should be designed suitable for the CAES application without overstressing any components when the cavern pressure is cycled from maximum to minimum and back to maximum up to 500 times per year during the design life of not less than 50 years of operation.

The cavern design should include consideration of the thermodynamic behavior of the stored air at operating temperature and pressure ranges under specified cycles of operation including the cold-standby mode for several months duration. The cavern leakage rate should not be more than 5.0 psi per day after stabilization. The cavern should be designed not only for the operating pressure ranges under the cyclic operating modes but also for stability under atmospheric pressure.

The air-conductor pipe, to be installed inside the inner permanent steel casing, should be designed with minimum annulus space, should protrude into the cavern to prevent entrainment of salt into the air stream, and should be of adequate internal diameter to reduce the friction loss to values that the liner pipe can withstand with a prudent margin of safety to prevent failure from any operational cause for the 50-year design life.

The air-conductor pipe should be designed to minimize sympathetic vibration in the entire line, such that the exit-air velocities should be sufficiently low, and such that the pressure difference across the FRP pipe at the wellhead is not excessive. The annular space between the air-conductor pipe and innermost cemented casing should be accessible above ground through a double-valved pipe connection for continuous injection of dehydrated air for corrosion control. Air for injection should be dried cavern air compressed using an electric motor-driven compressor.

The cavern should be designed so that during the first 10 years of operation, any condensation, creep of cavern walls, spalling of salt, or any anticipated leakage, when operated at rated capacity for 2000 hours per year, should not reduce the ability of the unit to perform for the weekly, daily, or continuous generation cycles. The cavern depth should be such as to optimize the selection and application of the turbomachinery, so that the performance of the unit has the final design parameters for the cavern prudently within the allowable stress values determined from tests of the salt-formation cores. The cavern should have 19 million cubic feet net usable volume.

4.2.3 Siting: A key element of a compressed-air energy storage (CAES) plant is the underground storage reservoir. The integrity of the reservoir, or its ability to contain pressurized air, governs the efficiency and economics of the CAES facility and its operation. The storage of compressed air or gas underground is a proven acceptable technique. Solution-mined salt caverns, hard-rock conventionally mined caverns, and porous-rock media can be successfully used to store compressed air. Since the technique of storing air is identical to storing natural gas, the successful long-term experience of storing natural gas underground illustrates the acceptability of this application.

The large air volumes required for a CAES facility necessitate the use (for economic reasons) of underground storage. Fortunately, approximately 75% of the United States has geological formations which are potentially favorable to air storage in solution-mined salt caverns, conventionally mined hard-rock caverns, and porous media.

Salt caverns are inexpensive to develop and are currently used to store oil, natural gas, and other hydrocarbons. Such cavities are typically produced by solution mining, wherein water is pumped in, and the resulting brine is brought to the surface for disposal. The self-healing characteristics of solution-mined salt caverns virtually eliminate air leakage. The air-delivery piping is also continued in a series of casings which are cemented into the salt formation and caprock to ensure against leakages. Many sites are suitable, and the solution-mining technology is commercially available. The West German Huntorf plant uses two salt caverns, and no measurable leakage has occurred since it was commissioned in 1978.

Hard-rock formations are currently used to store hydrocarbons. Many sites are suitable, and the hard-rock excavation technology is commercially available. A hard-rock cavern is more expensive than a salt cavern for a given volume, due to added labor and construction-equipment expense. Hence, the smallest possible rock-cavern volume per unit of output is desirable. This can be accomplished by hydraulic compensation, which is achieved by water from a surface reservoir flowing down a vertical shaft into the cavern to maintain a constant pressure. The process reverses during the charging operation. Such a design would need only about one-fifth of the volume of a salt cavern operating at variable pressure (constant volume) for the same energy-storage capability. The water-compensation system has been proven on a research basis, has been demonstrated commercially for hydro plants using "water-pistons" for water-hammer control, but has not been demonstrated via commercial-scale CAES plants.

The availability of suitable CAES sites within AEC's service area, which includes much of Southern Alabama and the Florida Panhandle, was considered with the possibility of expanding the site-selection area beyond the AEC service area only in the event suitable sites could not be found within the service area. The AEC service area is well suited to new power-plant construction for a number of reasons, including relatively low labor costs, reasonably priced land, good access to highways, good availability of fuels, railway, and water-transportation systems, sufficient water resources, and generally good air quality. These factors, combined with the obvious environmental and economic advantages of locating new generation facilities close to AEC's existing transmission system, led to the selection of AEC's service area as the "site-selection area."

Figure 4.2.3-1 depicts the Alabama geology suitable for potential CAES sites in porous rock (aquifer), hard rock, and salt dome. In the northwest quarter of the state, the paleogoic rocks are almost horizontal. The carbonate formations have widespread solution cavities. The deeper formations may be suitable for aquifer-type storage in sections where shales form a caprock. The center and northeast quarter of the state is formed by the Appalachian mountains and valleys. The mountains are crumpled igneous and metamorphic rocks. The valleys west of the mountains are formed by sedimentary rocks such as shale, sandstone, and limestone, with little metamorphism. These rocks have strongly folded and faulted and are highly inclined. The rocks in the mountains and valleys also require shale caprocks for aquifer storage due to the fractures and high dips. While there was a good possibility that suitable porous-rock storage sites could be found, such a site was not definitely known to exist. Furthermore, extensive geological investigations would be required for the definitive location of a suitable site. This alternative was not investigated further because the potentially suitable areas are all located 50 miles or more from AEC's existing transmission systems, and also due to the fact that porous-rock storage for CAES was relatively unproven in 1986.

Hard-rock formations suitable for CAES include the crystalline rocks, which form the Piedmont Upland, and the Cretaceous chalks extending in a band across the central portion of the state. Extensive geological exploration at a substantial cost would be required to positively locate a suitable site. The hard-rock alternative was not pursued because of its high cost relative to either porous-rock or salt-dome storage.

Two salt domes are located in the southwest corner of the state: the South Carlton and McIntosh domes. Salt in the South Carlton dome is located at a depth of approximately 16,000 feet, which is considered to be too deep for economical CAES plants. The McIntosh dome is the shallowest piercement dome in the salt basin. The dome pierces the Miocene sediment within 410 feet of the surface and is approximately 7,000 feet in diameter. The salt is of good quality and is used for brine production by Olin Corp. The caprock is overlain by a regular sequence of alternating beds of coarse-to-fine sand, gravel, clay, and shale.

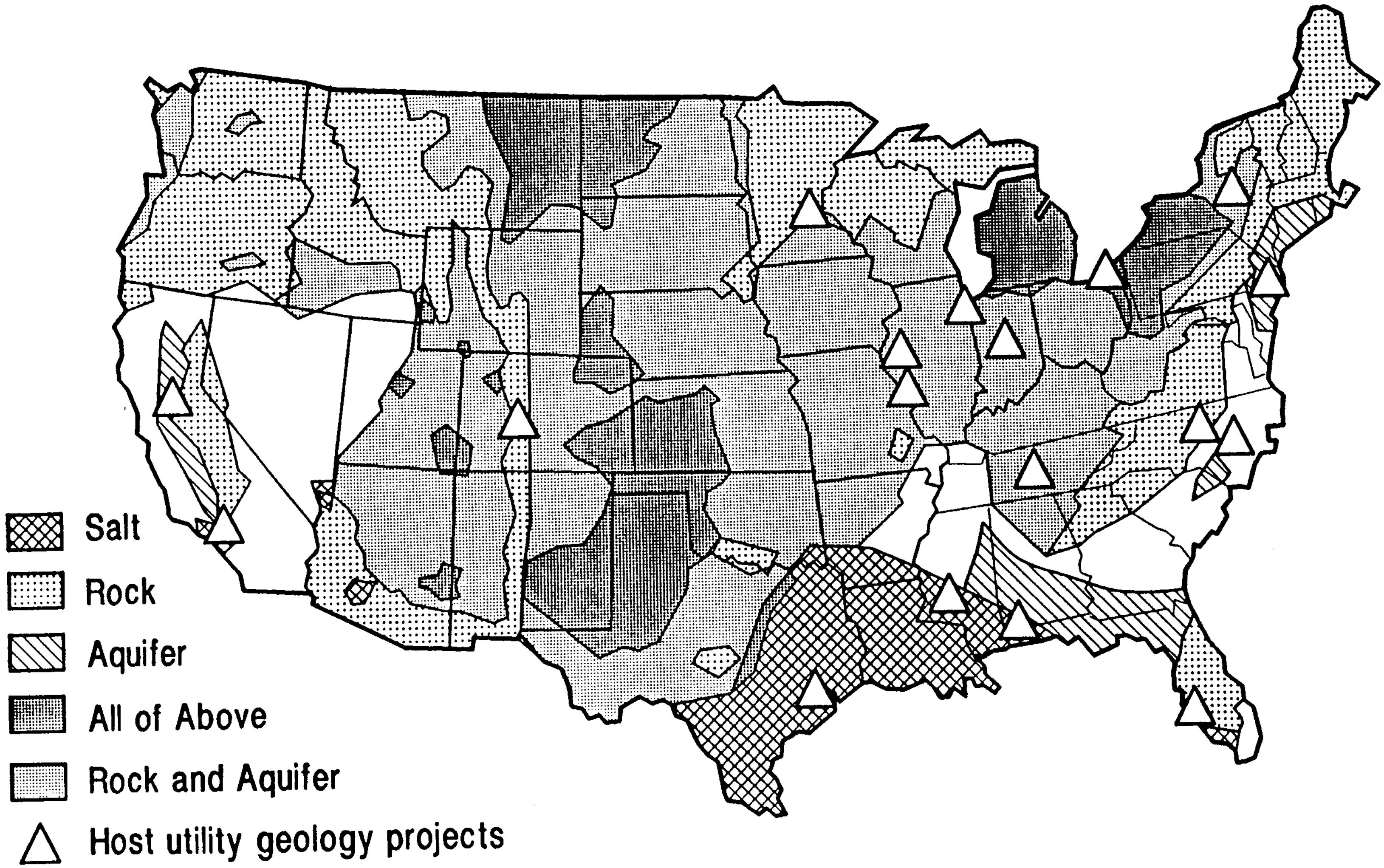

Figure 4.2.3-1. U.S. Geologic Formations Potentially Suitable for CAES

Although it is not in AEC's service area, there is a highly suitable existing storage cavern located near Hattiesburg, MS on the Petal Salt Dome (see Figure 4.2.3-2). This site was speculatively developed for storage of petroleum and propane; it has been used for propane storage. The McIntosh and Petal salt dome sites are geologically similar, and the operational temperatures and pressures used for a CAES facility would be approximately the same at either site. As a result, the cost and environmental impact of installing a CAES unit would be approximately the same at either site. The factors that vary are limited to site-purchase and developmental costs, related transmission improvements, and the way in which the CAES unit would be integrated into AEC's generation and transmission system.

The McIntosh salt dome is located in Washington County, Alabama, about 40 miles north of Mobile (see Figures 4.2.3-3 and 4.2.3-4). The McIntosh dome was discovered in 1945 by Gulf Refining Company and was developed for chemical purposes by the Olin Mathieson Company (now Olin Corporation). Olin has extracted large quantities of salt from the dome from about nine wells for use in chemical manufacturing. The resulting caverns were not designed for use as storage reservoirs and were not considered suitable as compressed-air energy storage caverns.

Olin controls the mineral rights for the McIntosh salt dome and owns most of the land above the dome, including the proposed 40-acre site. Olin was not willing to sell the site area to AEC but was willing to enter into a long-term lease agreement with AEC on favorable terms. Olin could also use the brine produced by solution-mining the two storage cavern(s) proposed by AEC, thereby eliminating the environmental problems associated with brine disposal.

The proposed site was located approximately 20 miles from AEC's Lowman plant (see Figure 4.2.3-5), and adjacent to two Alabama Power Company 115-kV transmission lines. AEC had investigated alternative means of integrating the McIntosh CAES facility into its generation and transmission system, and it had determined that the construction of a new 155-kV transmission line from the plant, combined with the establishment of an intertie with Alabama Power Company's 115-kV transmission line, should produce reliable interconnection with the proposed facility. Most of the new 115-kV transmission line would be constructed within existing rights-of-way, and only about 40 acres of additional off-site rights-of-way should be required to complete the necessary improvements.

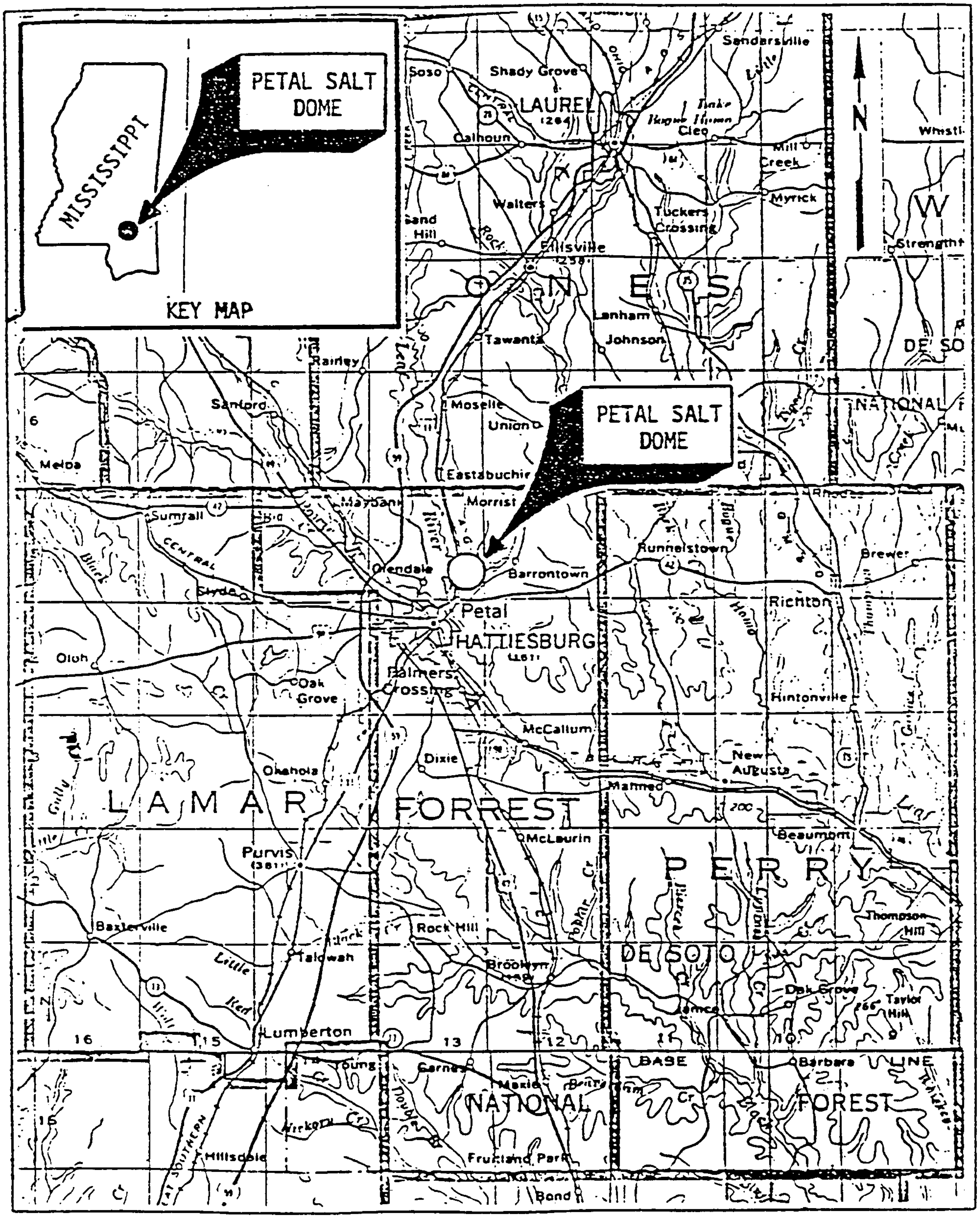

Figure 4.2.3-2. Location of Petal Salt Dome

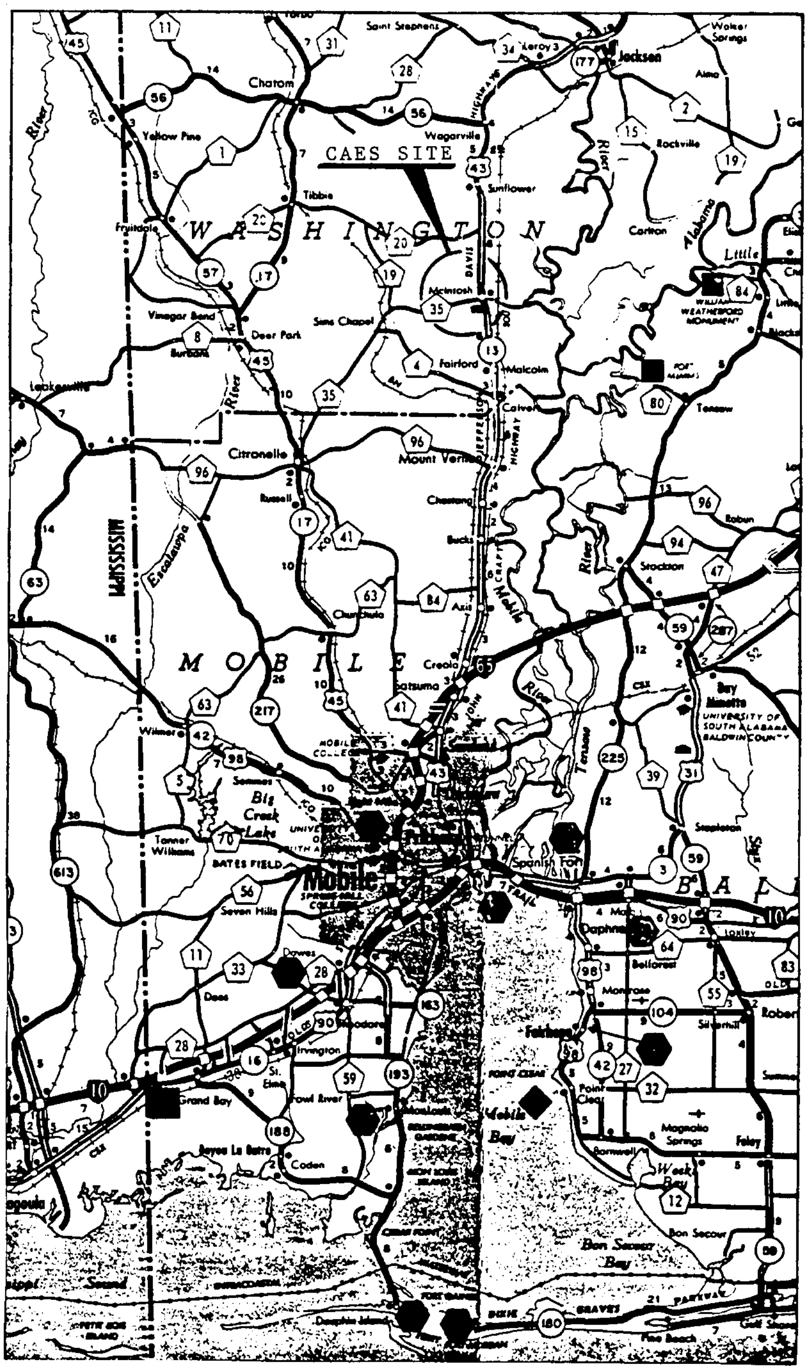

Figure 4.2.3-3. Location of McIntosh CAES Site

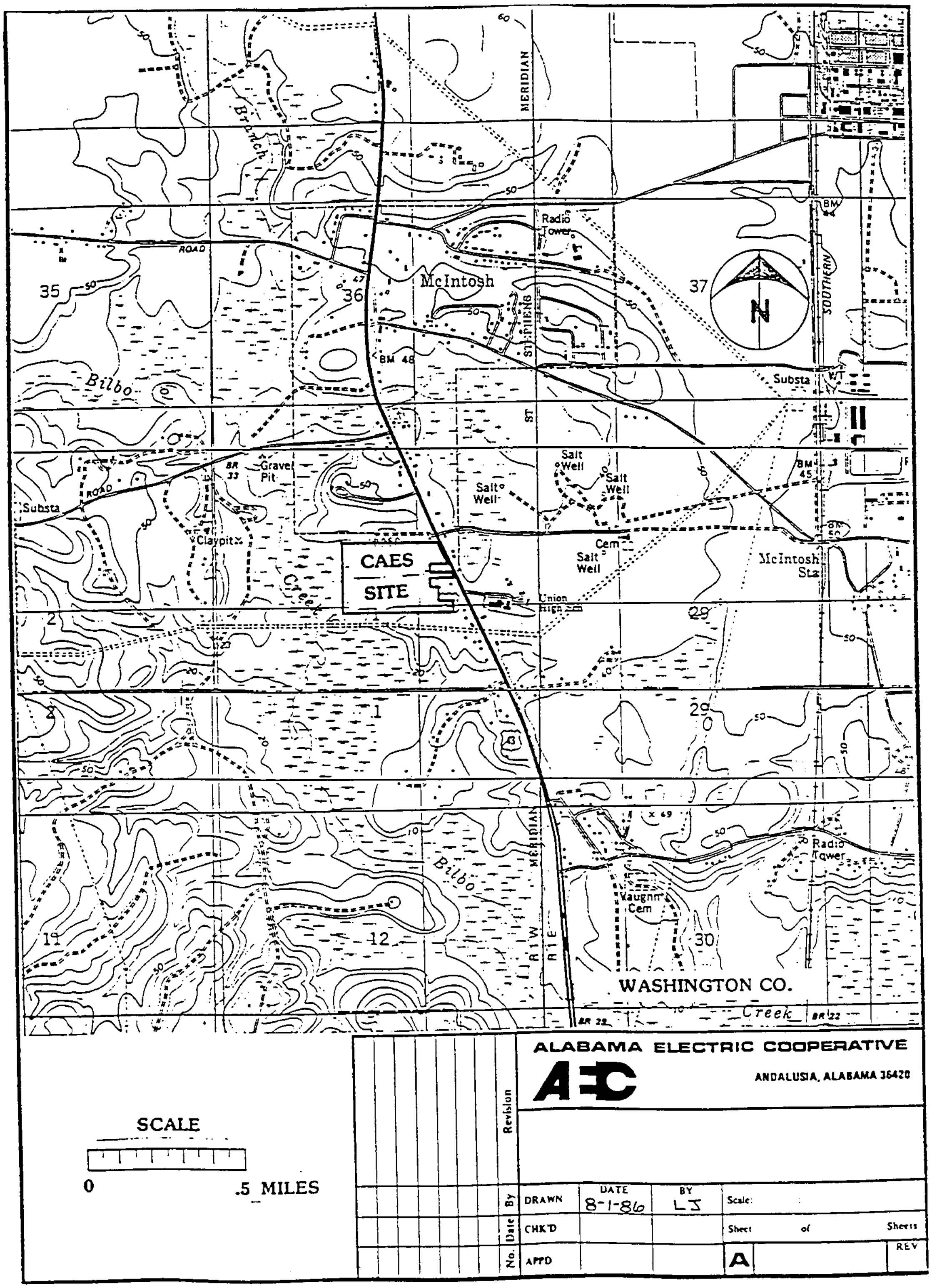

Figure 4.2.3-4. Location of AEC CAES Site (Closeup)

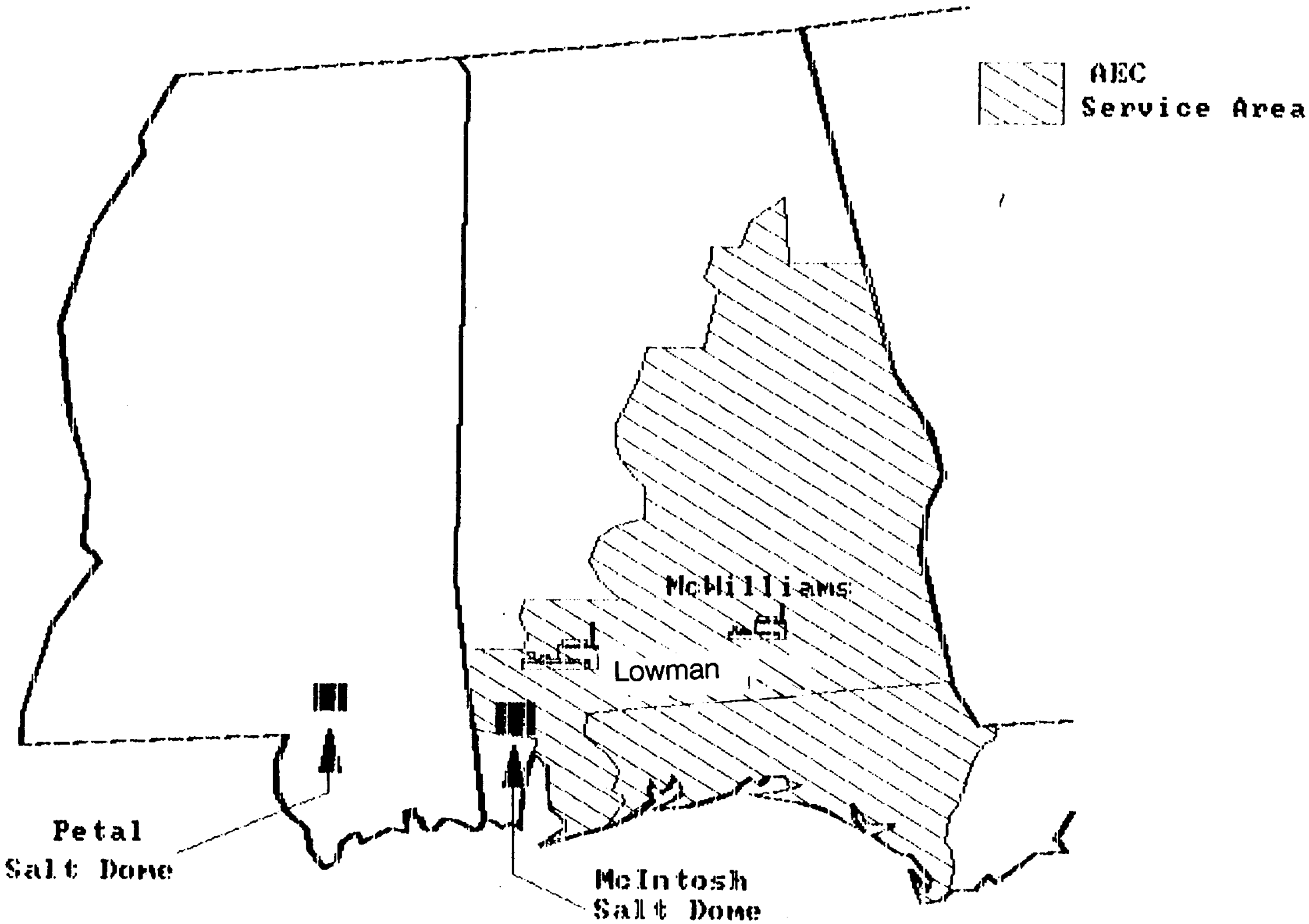

Figure 4.2.3-5. AEC CAES Siting Alternatives

Natural-gas fuel for the McIntosh plant will be provided from the Clarke-Mobile Counties Gas District which has an eight-mile pipeline located along Highway 43, adjacent to the site. The Gas District indicated that it had the capability to meet the demands of the proposed facility from this pipeline. However, the final source selected for the gas fuel was from a nearby higher-pressure pipeline.

The proposed CAES units would be remotely operated, with routine maintenance and supervision being provided from the Lowman plant. This should allow AEC to use the existing trained staff at the Lowman plant to operate the CAES units. Maintenance crews would be dispatched from the Lowman plant on an as-needed basis, inasmuch as it takes only 20 minutes to travel from the Lowman plant to McIntosh.

Development and operations of the McIntosh CAES plant does not offer major environmental problems. The site would not affect prime farm lands, underground species, wetland areas, known cultural resources, or other areas of unique environmental importance. Air- and water-quality impacts were considered to be limited and were later determined to be non-significant.

The Hattiesburg Storage Facility is a propane storage and handling facility located on the Petal Salt Dome (see Figure 4.2.3-2). The site area encompasses about 60 acres and contains two storage caverns, a leaching plant, fresh-water wells, product-injection pumps, brine ponds, and other ancillary facilities. Each storage cavern has a storage capacity of two-million barrels. Although developed for propane storage, the caverns are equally suited for storing compressed air.

The Hattiesburg Storage Facility was an equally owned joint venture of Fenix & Scisson, Inc., Laxton-Love, Inc., and Sun Gas Terminals and Storage, Inc. It was developed on a speculative basis in 1978 and 1979 at a cost of over $9 million, is currently unused, and could be purchased for an estimated price of $5 million.

The Petal Salt Dome is located approximately 38 miles from the Waynesboro substation, the tie-point between AEC and South Mississippi Electric Cooperative. The cost of constructing 230-kV transmission lines is about $200,000 per mile, resulting in a $7.4 million cost to provide a 38-mile direct connection to AEC's system. An additional $3.3 million would be required to establish a 115-kV link with Mississippi Power Company and necessary terminal facilities, for a total cost of $10.7 million for transmission-related improvements.

The Petal site is approximately 100 miles from the Lowman plant, providing some logistical problems. This distance would require additional employees to be stationed permanently at Petal, and it would create logistical problems in dispatching maintenance crews from the Lowman plant. As a result, it was estimated that additional employee costs, and additional travel time would total about $60,000 per year.

The environmental impact of developing the Petal site for CAES would be similar to developing the McIntosh site. The necessity to build 38 miles of 230-kV transmission line would require about 700 acres of land (assuming a 150-foot right-of-way).

The total site-related, estimated costs of developing the Petal site were $5.0 million for site procurement and development, $10.7 million for related transmission improvements, $0.6 million for additional employer-related costs, so that total site-related, estimated costs were $16.3 million.

The site-related costs of the McIntosh and Petal sites were similar, with McIntosh about 10% less. The Petal site includes some site improvements not present at McIntosh (fresh-water well, rail-unloading facilities, and propane-storage tanks); therefore, the actual difference in site-related costs was considered to be negligible. AEC could thus develop and operate a CAES facility at either location for approximately the same cost.

The McIntosh site offered three important advantages over the Petal site which are difficult to evaluate in economic terms. These advantages are:

1. The McIntosh site is located within AEC's service area, 20 miles from the Lowman plant. The proximity of the proposed plant would ease communications and managerial burdens of project development and operation.

2. Development and operation of the McIntosh plant would have essentially the same on-site environmental impacts as would CAES at Petal. The Petal site would require the construction of 38 miles of 230-kV transmission line, requiring about 700 acres of new rights-of-way (as compared to 40 acres for the McIntosh site), thereby making the McIntosh site more environmentally suitable.

3. The Petal site is located in Mississippi. This could cause some legal problems because AEC does not have condemnation rights for acquiring transmission line rights-of-way in Mississippi. This problem could be overcome by, for example, constructing the line jointly with South Mississippi Electric Power Association; it nonetheless created additional complication to project completion.

As a result of these factors, the McIntosh site was selected as the prime site. The Petal site was also considered suitable and could be developed in the event that unforeseen impediments arose in site development at McIntosh.

For an economically viable CAES plant, the above-ground equipment must be located very nearly on top of the underground caverns. If the distance from cavern to above-ground equipment is great, unacceptable pressure losses occur in the motive air piping. This limits acceptable plant sites to those almost directly above the McIntosh dome. To provide for the possibility of future expansions, a minimum plant size of 40 acres was required.

Olin controlled the mineral rights to all of the McIntosh Salt Dome and the surface rights to most of the land immediately over the dome. Olin controlled all sites large enough to be suitable for the proposed CAES facility. Thus, it was necessary to deal with Olin to obtain a plant site.

Figure 4.2.3-6 shows the approximate shoulder of the salt dome. The town of McIntosh is located along the northern portions of the dome, rendering this unsuitable as a plant site. Olin's existing brine wells are located on much of the dome that is east of Highway 43. The McIntosh High School is located on the southeast part of the dome, while the extreme southeast is bisected by a 115-kV double-circuit Alabama Power Company line. There are several dwellings and a wetland area on that part of the dome west of Highway 43 and north of County Road 35. The Olin Guest House and additional dwellings are located west of Highway 43 and immediately south of County Road 35. There is a wetland area and an additional cluster of dwellings on the portion of the dome west of Highway 43 and south of the Alabama Power Company 115-kV double-circuit transmission line.

There were two remaining areas considered potentially suitable for a CAES plant. These are the area east of Highway 43 and immediately south of County Road 35 and the preferred site, west of Highway 43 between the Olin Guest House and the Alabama Power Company transmission line, as shown in Figure 4.2.3-4. Olin had reserved the first site for potential future well development. It is also much closer to the main area of McIntosh.

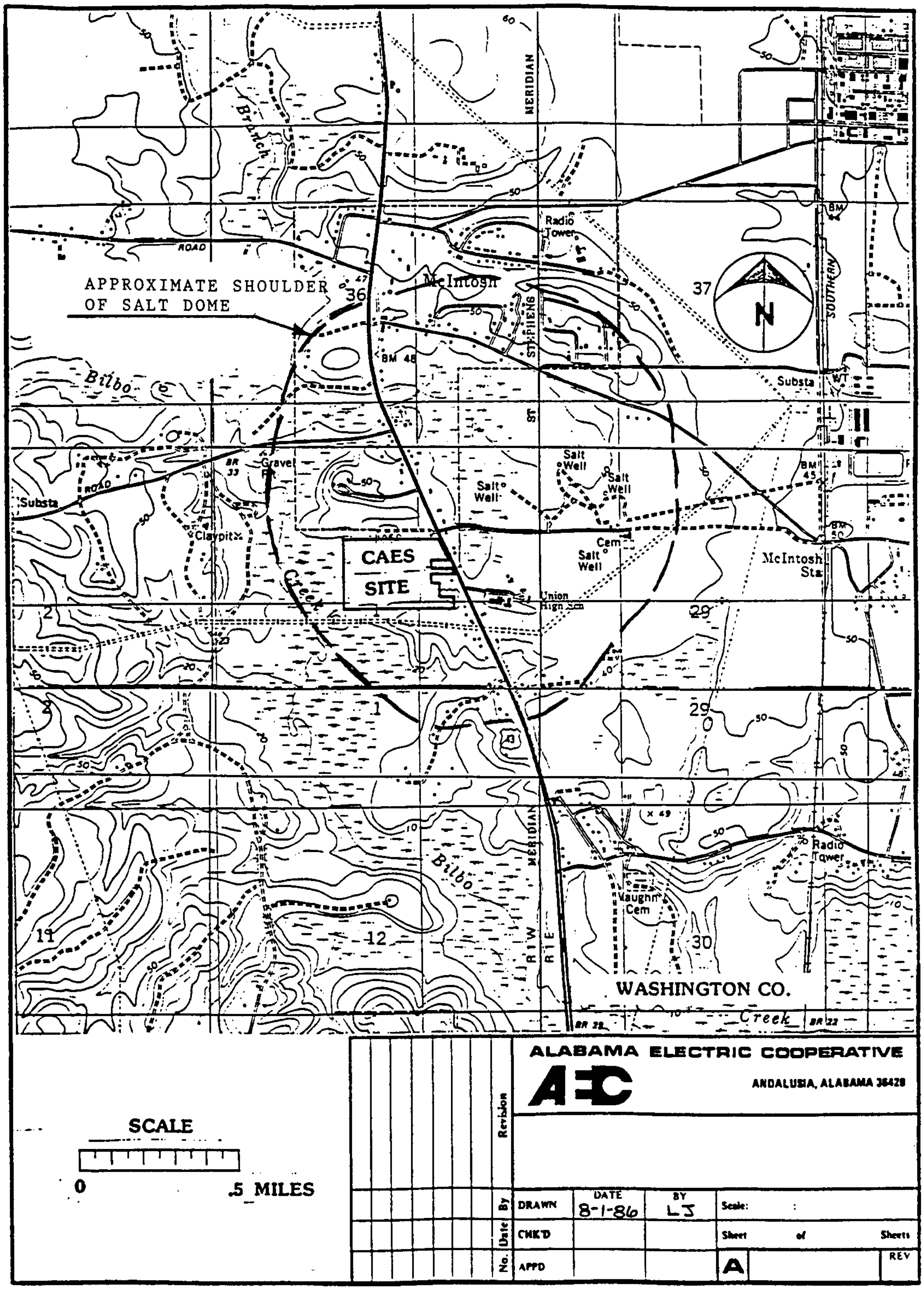

Figure 4.2.3-6. Location of Salt-Dome Shoulder

The preferred site was closer to the natural-gas pipeline and to the Alabama Power Company transmission line to facilitate an interconnection. The preferred site was offered by Olin, and since it posed no offsetting disadvantages, it was accepted.

A proposed plant layout, shown by Figure 4.2.3-7, and an alternative to this layout were considered, with the units running east-west (90° from the proposed arrangement). The proposed layout was more desirable for several reasons. The units are located near the back of this site. This puts them at the greatest possible distance from residences and the Olin Guest House, thus minimizing noise impact. The preferred site would minimize disturbance and erosion. It would also allow a maximum amount of tall timber to remain around the site, which would be more aesthetically pleasing.

4.2.4 Equipment: The type of equipment utilized in the CAES unit should not be prototype and should have a history of successful operation in a similar service. Standard designs or off-the-shelf equipment would be favored.

The generation/compression equipment required in the CAES plant consists of high-pressure combustion turbine, low-pressure combustion turbine, recuperator, motor/ generator, low-pressure compressor, intermediate-pressure compressor, high-pressure compressor, clutches, intercoolers and aftercooler, interconnecting piping, electrical systems, and control system.

The ancillary systems required to support the operation of the compression/ generation equipment consist of a) a fuel system which provides natural gas as a primary fuel from the gas pipeline through the fuel-gas compressor to the turbine combustors, as well as fuel oil which is stored in and supplied from a storage tank, and b) a cooling-water system in which the cooling-water pumps supply cooling water from the cooling tower to the interstage and after coolers. Other ancillary units include lube and waste-oil systems, interconnecting piping, electrical systems, control systems, and fire protection systems (water, Halon, and carbon dioxide).

4.2.5 Fuel: The CAES unit can burn natural gas, propane, or fuel oil. The decision to utilize natural gas as a primary fuel and fuel oil as a backup fuel was based on economics. Natural gas is a clean-burning fuel and can be readily obtained through an existing pipeline located on the east side of Highway 43. It was anticipated that an interruptable natural-gas contract could be negotiated at rates more favorable than either propane or fuel oil.

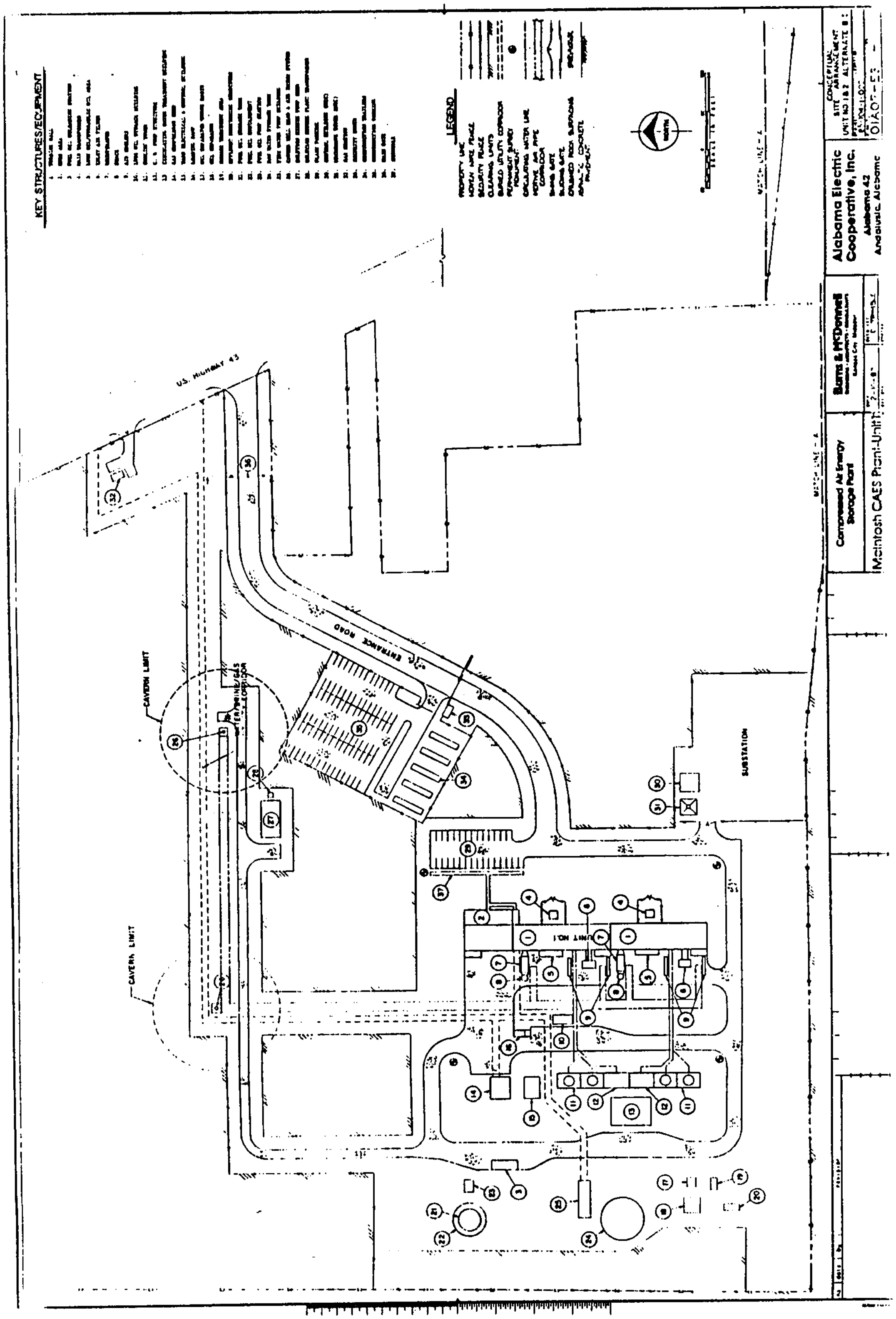

Figure 4.2.3-7. AEC CAES Plant Layout (Proposed)

The use of fuel oil as a backup fuel would allow natural gas to be contracted on an interruptable basis, meaning that the delivery company should not have to include delivery of gas to the CAES unit when maintaining or upgrading its delivery capacity. Since no additional pipeline or storage facilities would have to be constructed, other than a metering station and a distribution pipeline from Highway 43 into the plant site, the natural gas could be obtained on a more competitive basis.

The unit would be designed to burn natural gas or No. 2 fuel oil singly and be able to change from one fuel to the other automatically under any normal load conditions. Fuel transfers would include time delays as required to establish proper fuel pressure before transfer is implemented. Fuel oil would be used for black start, so that a gas compressor would not be necessary for start-up.

Exhaust emissions would be limited to the following:

a) Plant emissions of nitrogen oxides (NO_x) and SO_2 would be limited to comply with Standards of Performance for Stationary Gas Turbines (Title 40 Code of Federal Regulations Part 60, Subpart GG, as promulgated in Federal Register, September 10, 1979) at all loads and operating conditions. NO_x emissions would be limited to not more than 2.30 lb NO_x per MW-hr when burning natural gas and not more than 3.30 lb NO_x per MW-hr when burning fuel oil.

b) Limiting NO_x emissions to not more than 1.15 lb NO_x per MW-hr when burning natural gas through application of water injection into the combustion process may be required. It was determined that water injection is not required for the first CAES unit, but ports for such injection are included for the first unit, so that NO_x emissions can be permitted if a second CAES unit is built on the site.

c) SO_2 emissions would be limited by restricting the sulfur content of fuel.

4.2.6 Additional: Some further specifications are given in Table 4.2.6-1. It was further specified that the charging of the cavern to maximum operating pressure would use no more than 2,083.9-MW total energy consumption. The maximum operating pressure and temperature were specified as 1140 psia and 130°F. The maximum generator capacity

Table 4.2.6-1

Additional Design Specifications

Heat rate:

	Net Heat Rate (HHV) (Btu/kW-hr)	
	Gas	No. 2 Fuel Oil
Max 110 MW	4568	4353
Min stable 10 MW	6115	5622

Expander train inlet air mass flow with recuperator:

	Air Flow (lbs/second)	
	Gas	No. 2 Fuel Oil
110 MW	340.4	343.4
10 MW	79.7	78.0

Recuperator by-passed:

Max net	372.9 (95 MW)	375.4 (93.8 MW)
10 MW	89.3	87.5

would be 111.5 MW at 13,800 volts, 85% power factor. The motor capacity would be 72360 Bhp. The operation response with hot stand-by to full load would be 13 minutes, and 9 minutes with emergency start. Generation mode, as well as synchronous condensing mode, to blow-off valves closed for compression would not exceed 75 minutes.

The cavern maximum design pressure was specified as 1130 psig at 130°F, and cavern minimum design pressure as 0 psig at 40°F. The cavern minimum operating pressure was specified as 650 psig, allowing five starts of the unit in the compression mode. It is understood that all of the above pressures would be measured at the well-head.

The recuperator effectiveness at 110-MW load would be 75.0%, and at 10-MW load, 81.1%, with the effectiveness being given as the temperature difference between the air out and the air into, divided by the temperature difference between the gas into and the air into.

The plant would be tested in compliance with the owner's permit from the Alabama Department of Environmental Management, Air Division, when operating at any load, with the maximum emissions not exceeding those given in Table 4.2.6-2, with and without water injection, and all emissions measured simultaneously. The exhaust from the unit while burning the specified fuels without additives would appear as a "Clean Stack," and smoke levels would not exceed 20% opacity.

Table 4.2.6-2

Maximum Emissions (lb/MWh)

	With Water Injection		Without Water Injection	
	Gas	No. 2 Fuel Oil	Gas	No. 2 Fuel Oil
Nitrogen Oxides	1.15	1.65	2.3	3.3
Carbon Monoxide	0.49	0.49	0.33	0.33
Hydrocarbons	0.032	0.032	0.016	0.016

Foundation design was based on the Gibbs & Hill document issued January 9, 1989. This document presented the results of the geotechnical evaluations performed at the CAES-facility site and summarized the specific foundation criteria which would be implemented during the detailed engineering. The foundation-support systems dictated by the foundation-design criteria included tapered, concrete shell piles, timber piles, and spread footings/mats. The piles were to have a bearing capacity of 35 tons at 40 ft, 40 to 70 tons at 50 ft, and 100 tons at 90 ft. The spread footings/mats were to have a bearing capacity of 1200 lb/ft^2, with a 1" limit for total settlement. The supporting structure for the facility buildings and equipment are given in Table 4.2.6-3. The fire-water/raw-water pump house, gas compressor, cooling-water treatment building, electrical building, and pipe supports were each spread footings with 1200 lbs/ft^2 bearing capacity. Roadways would utilize geosynthetic select fill with a granular subbase and crushed aggregate surface, and permanent paved roads would have a granular subbase, granular base course, and asphaltic-concrete or cement surface course.

Table 4.2.6-3

Foundation-Support Systems

Item	System	Capacity (tons)	Depth (ft)
Turbine Pedestal	shell pile	100	90
Turbine-Bldg. Structure	shell pile	45-75	50
Turbine-Bldg. Floor	shell pile	40-75	50
Recuperator Stack	shell pile	100	90
Cooling Tower	timber pile	35	40
Fuel-Oil & Raw-Water Tanks	timber pile	35	40
Lube-Oil/Hyd.-Oil Storage Bldg.	shell pile	40-75	50
Main Transformer	shell pile	40-75	50
Lube-Oil Storage Bldg.	timber pile	35	40

The architectural design was performed by Gibbs & Hill, following the guidelines set forth in the contract. Design of plumbing, fire protection, HVAC, etc., were performed by its building-services group. The efforts of the architectural and building-services personnel were combined to complete the design of the buildings. Electrical design was undertaken from the Burns & McDonnell one-line drawings which accompanied the contract documents. The instrumentation was controlled by a portion of the contract which specified a distributive-control system (DCS) required because the facility was an unmanned plant controlled from a remote location. The system was incorporated in the turbomachinery purchase due to the extensive interface between the turbomachinery and the control system. Requirements for the DCS included the ability to operate the plant from local consoles at the site, from the Lowman Plant via microwave, and from Andalusia via microwave. The instrumentation not a part of the turbomachinery purchase was designed by Gibbs & Hill. Mechanical design of the plant, excluding the turbomachinery, was performed by Gibbs & Hill's mechanical group.

4.3 Bidding Process

AEC prequalified seven bidders for engineering and construction. The request for tenders was sent to the prequalified bidders. Each bidder returned his tender and reviewed his proposal with AEC personnel. After the receipt of the tenders and the bidders' presentations, the bids were opened in private, evaluated, and the decision was finalized as to the action to be taken. A chronology of the bidding process is give in Table 4.3-1.

Table 4.3-1

Bidding-Process Chronology

Date	Item
6/86	AEC - initial meeting
11/86	First draft of specifications
12/86	AEC meeting to review design and costs
87	Environmental permits complete: issued to bidders
7/14/87	50-MW bids received
7/27/87	Negotiations with all bidders
9/21/87	100-MW bids received
11/87	Negotations with all bidders
12/87	Negotations with Gibbs & Hill (G&H), United Engineers
1/15/88	Letter of recommendation to AEC
1/26/88	Notify G&H, exclusive negotiation to contract
2/1/88	Harbert joins G&H in Joint Venture
2/2/88	Limited notice to proceed
2/4/88	Negotiate with G&H
2/11/88	Burns & McDonnell (B&M) first comments on specifications 20000, 20100, and 20200
2/16, 17, 18/88	Negotiations, G&H, Div. 19 review committee set up, discuss Fenix & Scisson (F&S) 1/13/88 letter received at 2/4 meeting (new construction and engineering (C&E)), and F&S provides 2/12/80 Test Hole No. 2 agreement
2/19/88	Joint Venture (JV) requested to obtain letter from the bonding company committing to sign and extend bid bond
2/22/88	3/15/88 set as goal for edit of C&E
2/26/88	First set of conformed pages to JV contract (O1A, Div. 2,5,7,13)

Section 5

ENVIRONMENTAL PERMITS AND LICENSING ISSUES

AEC is sensitive to environmental issues and in the past has made a concerted effort to comply with all rules and regulations from all governing agencies. The CAES plant is no exception; AEC has made extensive environmental studies considering all areas of potential impact, including local social and economic considerations.

AEC received numerous informational requests concerning the CAES project, but no comments were received, including those from scoping meetings, critical of the project or identifying impacts not previously addressed. The federal and state agencies which were consulted about the environmental impacts of the CAES project prior to the scoping meetings did not choose to attend, apparently because they were satisfied that the CAES project would not result in major environmental impacts.

5.1 Regulatory Requirements

5.1.1 Federal agencies:

1. Rural Electrification Administration
   a) Environmental analysis for McIntosh plant.
   b) Submit research proposal for funding assistance.
2. U.S. Department of the Interior Fish and Wildlife Service.
   a) Compliance with the Fish and Wildlife Coordination Act.
   b) Compliance with the Endangered Species Act.
3. Department of the Army Corps of Engineers

   Review of site survey to determine that no Army permit is required.
4. U.S. Department of Agriculture Soil Conservation Service

   Review of site survey for prime farmland determination and impact.
5. National Pollutant Discharge Elimination System

   Permit to operate plant.

5.1.2 State agencies - Alabama:

1. Alabama Department of Environmental Management

    a) Permits to drill wells.

    b) Air permit in accord with the Alabama Air Pollution Control Act.

    c) National Pollutant Discharge Elimination System (NPDES) permit.

    d) Underground Injection Control (UIC) permit (Olin).

    e) Permit for solution-mining of caverns.

2. Alabama Historical Commission
   Archaeologist report submitted and reviewed to determine impact on historical places or cultural resources.

3. Alabama Highway Department
   Permits for road turnouts into state-right-of way, overhead telephone and electrical service crossing a highway, and road borings for brine and raw-water pipelines.

5.1.3 Local agencies:

1. Health Department - Washington County
   Survey and permit to construct and install septic tanks and a sewage-disposal field.

5.2 Schedules (Public Meetings and Notices)

December 25, 1986: AEC placed a notice in the Chatom "Call-News Dispatch" announcing a Public Scoping Meeting to be held at the McIntosh City Hall, on January 15, 1987. The meeting was held, with approximately 45 persons in attendance.

December 29, 1986: AEC placed a notice in the "Hattiesburg American" announcing a Public Scoping Meeting to be held at the Jackie Sherril Community Center, in Hattiesburg, Mississippi on January 14, 1987. The meeting was held, with approximately 20 persons in attendance.

January 12, 1987: "Federal Register" contained the announcement for the McIntosh and Hattiesburg Public Scoping Meetings.

The three main topics to be presented at the Public Scoping Meetings were need, environmental, and technical. The presentation regarding need for the CAES plant included AEC familarization, AEC's function as a cooperative, why the power storage was required, and the benefits of storing energy. The environmental presentation described the impact the CAES plant would have on prime farmlands, wetlands, floodplains, cultural resources, endangered species, habitat, air quality, water quality, noise levels, and aesthetics. The technical presentation included the required equipment for the CAES plant and how the plant would operate. Both meetings made the public aware that the favored site was the McIntosh site.

April 24, 1987: "Federal Register" contained the REA announcement of its "Finding of No Significant Impact." This announcement was also published in the Chatom "Call-News Dispatch" and the "Hattiesburg American." Since a "Finding of No Significant Impact" does not require submittal of a project environmental impact statement (EIS), no such document was needed or issued.

Section 6

PROJECT ADMINISTRATION

6.1 Contracts and Negotations

6.1.1 Site: On May 15, 1988, Olin Corporation and AEC entered into an agreement to provide AEC with a site for the CAES plant. This agreement contains provisions for a 50-year lease, in favor of AEC, with an option to renew the lease for an additional 25 years, giving AEC surface rights to a 40-acre tract of land adjacent to U.S. Highway 43, as indicated by Figure 6.1.1-1. AEC was obligated, if required, to obtain an environmental impact statement, environmental permits, or approval of any environmental agencies. AEC later negotiated with property owners and purchased four lots which join the leased property, as shown in Figure 6.1.1-1.

6.1.2 Solution mining - brine disposal: The Olin-AEC contract described in 6.1.1 contains the rights for AEC to solution-mine a minimum of one but not more than four caverns which would have a maximum capacity of 110% of 3,270,000 barrels capacity in each cavern. The cavern leaching would be done under Olin's existing UIC permit, other applicable permits, and cavity storage license. The maximum cavern pressure would be 0.9 pounds per square inch per foot gradient. Olin contracted to supply AEC with injection water (salt content of not more than 60 grams per liter and flow rate between 1400 and 2000 gallons per minute). The brine from the cavern leaching would be returned to Olin for use in Olin's chemical process.

6.1.3 Rights-of-way: The Olin-AEC contract described in Section 6.1.1 contains a temporary right-of-way for the water from Olin and the brine return to Olin for the solution-mining. The contract also contains a right-of-way (for the CAES plant raw-water supply) which runs concurrent with the property lease.

6.1.4 Consulting engineering services: AEC contracted with Burns & McDonnell Engineering Company for CAES-plant engineering services. Burns & McDonnell was named engineer for the project which, per the CAES bid documents and contract, defines the term, "engineer", to mean the engineer employed by the owner to provide engineering services for the project, along with said engineer's duly authorized assistants and representatives.

Shaded areas indicate AEC purchased property

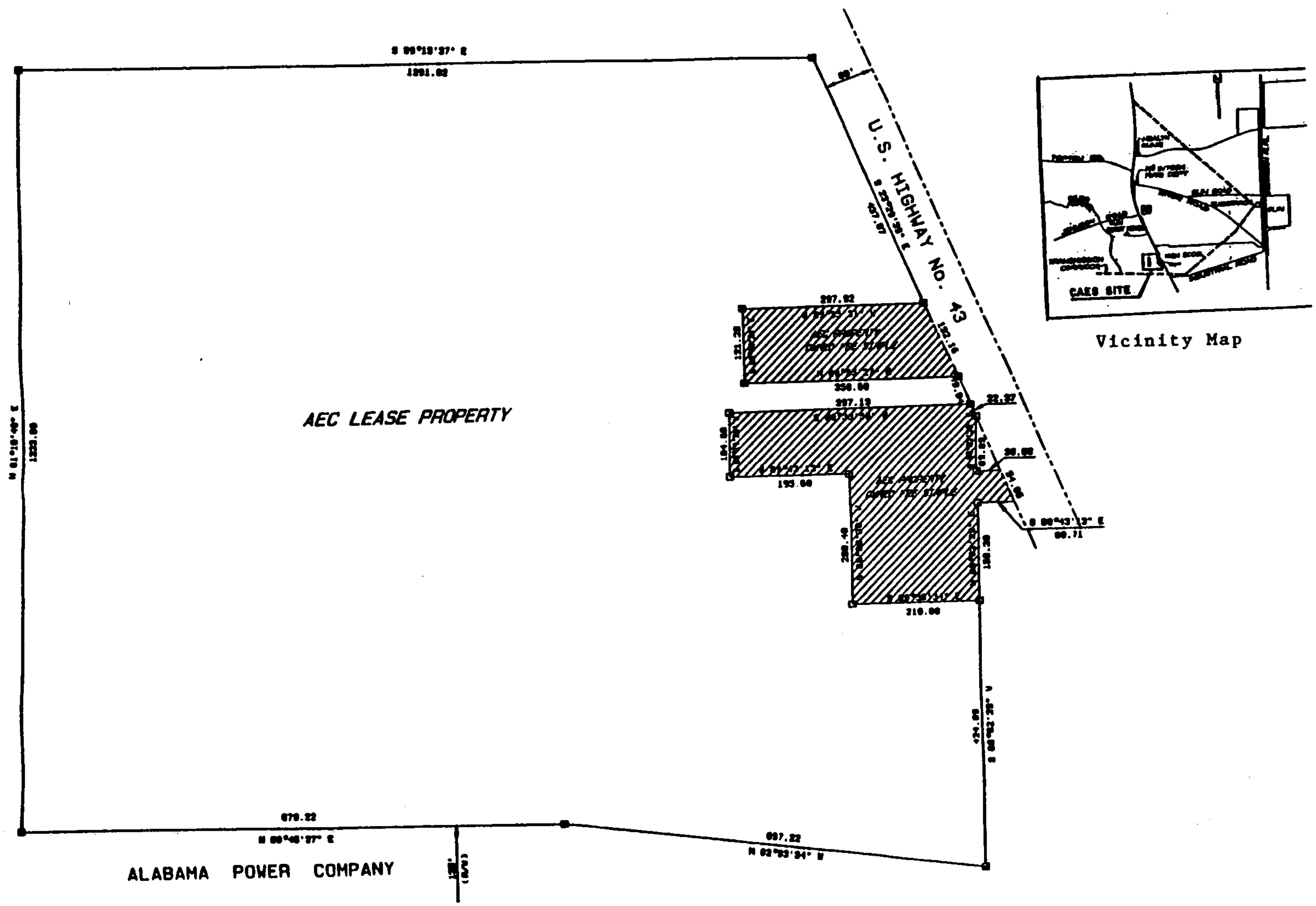

Figure 6.1.1-1. AEC Lease and Purchased Property

6.1.5 Construction: The contract was written by Burns & McDonnell and is a four-volume document, with the contract being a REA Form 200 (Rev 9-72). The first three volumes contain the modified contractor's proposal, including the following:

1. Notes and instructions to bidders REA Form 200 modified:

   Article I - General

   Article II - Construction

   Article III - Payments and Releases of Liens

   Article IV - Particular Undertakings of the Bidder

   Article V - Remedies

   Article VI - Miscellaneous

2. Supplement to contractor's proposal:

   a) Acceptance

   b) Accepted clarifications and exceptions

3. Contractor's bond (REA Form 168)

4. Certificate of completion - construction contract (REA Form 187)

5. Waiver and release of line (REA Form 224)

6. Certificate of contractor (REA Form 231)

7. Subcontract (REA Form 282)

8. Notice to contractors and sellers (REA Form 271)

9. Appendix F - Contractor's affirmative action plan for equal employment opportunity under Executive Orders 11246 and 11375 (Form AD 425)

10. Supplement to REA Form 200

11. Detailed specifications:

    Division 1 - General requirements

    Division 1A - Application, design parameters, and criteria

    Division 2 - Site work

    Division 3 - Concrete

Division 4 - Masonry

Division 5 - Metals: structural and miscellaneous

Division 6 - Wood and plastics

Division 7 - Thermal and moisture protection

Division 8 - Finishes

Division 10 - Specialties

Division 11 - Equipment

Division 12 - Furnishings

Division 13 - Special construction:

   a) Distributed control system

   b) Vibration monitoring system

   c) Control panels

   d) Process instruments

Division 14 - Conveying systems

Division 15 - HVAC and plumbing

Division 16 - Electrical

Division 17 - Unassigned

Division 18 - Mechanical and fire protection

Division 19 - Performance and acceptance tests

Division 20 - Guarantees, expected performance, cavern and equipment data, and organization of bidders' submittal and supplemental bid information

12. Exhibits

13. Piping design tables

The fourth volume includes supplemental data. (Contractor and seller furnished data clarifying the work to be done and equipment to be furnished.)

6.2 Project Management

6.2.1 CAES project team:

AEC

Vice President

Manager, Power Plant Construction

Project Engineer (on-site)

Consulting Engineer (Burns and McDonnell)

EPRI

EPRI interest and participation in the project dates to 1975, with the decision to perform research on the viability of CAES in the United States. R&D efforts on CAES continued: to identify a host utility; to provide monetary support for first-of-a-kind plant components (e.g., the recuperator); and to utilize EPRI talent, personnel, and consultants, as required. The EPRI personnel involved in the CAES Project are depicted in the following job-title listing:

Project Manager (surface activities)

Project Manager (subsurface activities)

Project Manager (representing EPRI on-site as Engineer of Record, Demonstration Engineer, and Test Engineer. This engineer acts in AEC's behalf as Site Project Manager.)

Consultant for Technical Engineering Support (Energy Storage and Power Consultants (ESPC))

Joint Venture (Harbert/Gibbs & Hill)

Harbert International

Joint-Venture Project Manager

Joint-Venture Financial Manager

Joint-Venture Controls Manager

Project QA/QC

Construction Manager

Procurement Manager

Cost-scheduling Engineer

Administrative/Material Control

Civil Superintendent

Pipe/mechanical Superintendent

Electrical/instrumentation Superintendent

Project Engineer

Pipe/mechanical Engineer

Electrical/instrumentation Engineer

Survey-party Chief

<u>Gibbs & Hill</u>

Director of Engineering

Design-Engineering Project Manager

Project Controls Engineer

Technical Director

Civil Engineer

Structural Engineer

Architectural Engineer

Mechanical Engineer

Electrical Engineer

Instrument & Controls Engineer

Consultants

<u>Fenix & Scisson (drilling and cavern development subcontractor to Joint Venture)</u>

Vice President

Project Manager

Site Superintendent

6.2.2 Project schedule: The original project schedule, as depicted in Figure 6.2.2.-1, was based on the premise that cavern development would be the operation requiring the greatest amount of time to complete. The drilling of the well, cavern leaching, testing, dewatering, conversion, and charging with air thus constituted the critical path. The projected time for cavern development was estimated to be 30 months, and the remaining engineering, procurement, and construction activities were dispersed in this period. The schedule had a start date of August 11, 1988, and the engineering was scheduled for 15 months. Construction was scheduled to begin on February 1, 1989 and continue until the end of September, 1990, with the cavern schedule extending to January, 1991, when startup activities would begin. Startup and testing would continue until plant acceptance, scheduled for June 10, 1991.

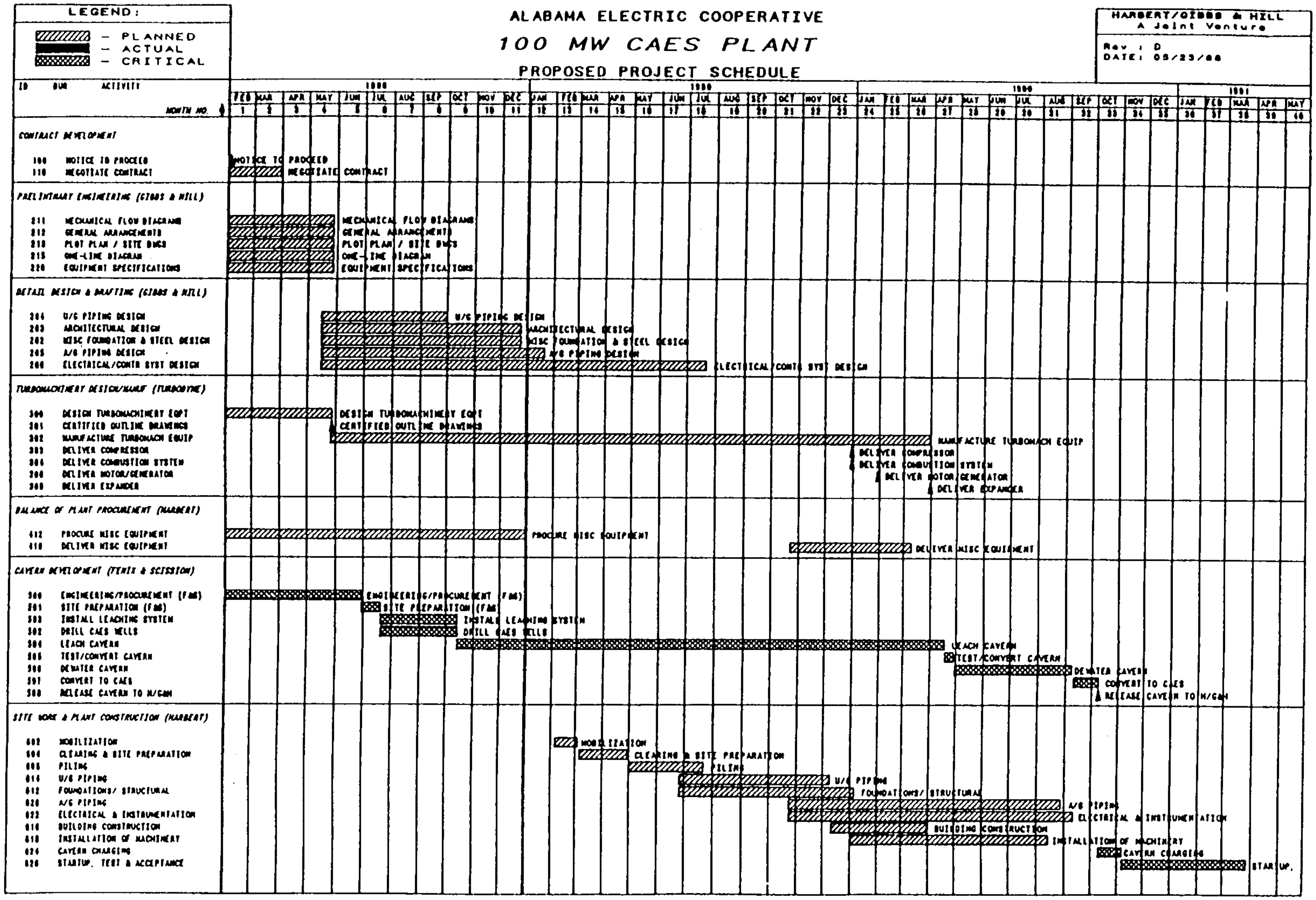

Figure 6.2.2-1. AEC 100-MW CAES Proposed Project Schedule

Section 7

TEST HOLES

During 1987, test holes No. 1 and No. 2 were drilled at the McIntosh site. Test hole No. 1 defined the perimeter of the salt dome. Test hole No. 2 was drilled to determine the salt quality and verify a suitable location for the first cavern on this site.

Test hole No. 2 offered a source for additional testing; AEC and EPRI agreed to complete the hole to provide access into the completed cavern as a possible aid for dewatering the cavern, as well as temperature, pressure, and corrosion tests during operation of the cavern. The original test hole No. 2 was cased to a depth of 455 feet with 12-3/4" OD casing, and a 7-7/8 diameter hole was drilled to 2700 feet. Preparation of the test hole as a permanent feature began by drilling out the current plug at the bottom of the surface casing; the hole was then reamed to 14" diameter from the bottom of the surface casing to a depth of 1453 feet, and the hole was opened to 11" diameter from 1453 feet to 1550 feet. A 10-3/4" OD casing was installed from the surface to a depth of 1468 feet and cemented. The cement was topped out, and slips were installed, after which a double-stud adapter was installed on the Braden head to reduce the flange size. A cement bond log was run, as well as a temperature log and a vertilog which would be used for corrosion comparisons in the future. The 12" casing was cut off above-grade, and a Braden head was installed, which has two 1" flanged connections 180° apart below the flange.

The test hole was pressure-tested with nitrogen to a pressure of 1135 psig with no leakage; then, a valve with a blind flange was installed, and the hole was pressured to approximately 200 psig. The test hole is located 30 feet from the main well, and the reaching process exposed the lower extremity of the hole, creating an entrance into the storage cavern via the test hole. When construction of the AEC CAES facility began in the latter part of July 1988, with the initial efforts were expended to clear brush and provide a location for Fenix & Scisson to have a drilling subcontractor, Griner Well Drilling, move a drilling rig and equipment on-site, August 3, 1988.

The first drilling operation was completing test hole no. 2 to provide a second entrance into the storage cavern for testing and research purposes. Site preparation included cleaning the mud pits used to drill test hole no. 2 and provide compacted fill for a suitable base for the drilling rig. The rig arrived, and rig-up was completed on August 5, 1988. Concurrent with the rig erection, a subcontractor, Homco International, was sandblasting and applying Ruff-Cote to the casing, as specified by the contract. EPRI's drilling and cavern consultant (Al Medley) arrived on-site August 5, 1988. Sandblasting and Ruff-Cote of the casing, leveling of the rig, and delivery of brine for drilling was completed August 6, 1988. The first drilling of the cavern well began August 7, 1988.

The test hole had been previously drilled to a depth of 2706 feet with an 18" casing run to a depth of 279 feet and cemented; a 12" casing was also run to a depth of 455 feet and cemented. The first drilling entailed drilling out the cement plug at the bottom of the 12" casing. After drilling to a depth of 618 feet, circulation was lost, and cement was pumped into the hole to resolve the lost circulation problem. On August 8, the hole was re-entered and drilled through the cement to a depth of 709 feet. The drill was removed from the hole and fitted with a 11-1/2" hole opener and a 7-5/8" drill bit.

Appendix A.1

ORIGIN AND EVOLUTION

The original concept of a turbine was by Hero of Alexandria in the second century, B.C. The first evolutionary step utilizing the turbine as a combustion turbine occurred with the issuance of a patent to John Barber in 1791. In 1872, F. Stolze was granted a patent for a fire turbine which consisted of a separately fired combustion chamber, a heat exchanger, and multistage axial-flow compressor directly coupled to a multistage reaction turbine, which was a significant advancement.

George Brayton presented the basis for analysis of the simple gas turbine cycle in 1873, and the first successful gas turbine was built in Paris in 1903, claiming an operating efficiency of three percent. The explosion-type turbine was developed in 1905 by Hans Holzwath, who with various associates continued the development of the gas turbine for about 30 years. About 1927, Stal-Laval of Sweden was assigned a patent for compressed-air energy storage utilizing the gas turbine.

During the pre- and post-World War II years, the gas turbine technology matured quickly because of the need for a reliable power and propulsion engine and because of the advances in associated technology, such as metallurgy and electronics. This maturity has made the gas turbine a valuable contribution for power generation, mechanical drives, as well as marine and aircraft propulsion.

The concept of compressed-air energy storage is the exploitation of old ideas and improved technology. The basic difference with the CAES concept and the patent issued to F. Stolze in 1872 is the unique idea of compressing, storing, and scheduling the use of compressed air in the combustion turbine at a time when power is needed rather than utilizing the air immediately after compression.

The successful operation of the first CAES plant, in 1978 at Huntorf, West Germany by NWK, proved the validity of the CAES concept. This plant created a potential market for equipment manufacturers and new cost-effective options for utilities to supply their intermediate peak demands.

First U.S. CAES plant: Research was performed, as were studies by several utility companies and engineering groups. In 1981, Soyland Power Cooperative of Decatur, Illinois initiated the construction of the Soyland CAES facility. The project was halted in February 1983, not because of any intrinsic difficulty, but as a result of a policy decision of the Soyland Board of Directors to revert to a transmission/distribution cooperative and not to assume the burden (technically and financially) to become a generation-based cooperative-owned utility.

Alabama Electric Cooperative, as early as 1979, had performed a study involving CAES technology, and in 1985 it entered into a joint feasibility study with the Electric Power Research Institute (EPRI). This study and additional engineering studies led to the conception and construction of the first CAES plant in the United States by the Alabama Electric Cooperative.

Alabama Electric Cooperative (AEC) is a generation and transmission cooperative formed in 1941 to supply power to its member-owners. AEC serves 35 Alabama counties and 10 Florida counties. AEC's member-owners are 16 distribution cooperatives, four municipals, and two industrials located in central Alabama, South Alabama, and the panhandle of Florida. As of 1988, AEC had 598 MW of installed base-load capacity, 1800 miles of transmission lines, agreements for use of transmission lines owned by others (wheeling agreements), and 130 substations. Appendix A.2 contains a list of AEC member-owners.

The AEC headquarters address is:

Alabama Electric Cooperative, Incorporated
P.O. Box 550
Andalusia, Alabama 36420
(205) 222-2571

Appendix A.2

ALABAMA ELECTRIC COOPERATIVE MEMBER-OWNERS

Power Distribution

1. Baldwin County EMC
2. Central Alabama Electric
3. Choctawhatchee Electric
4. Clarke - Washington EMC
5. Coosa Valley Electric
6. Covington Electric
7. Dixie Electric
8. Escambia Electric
9. Gulf Coast Electric
10. Pea River Electric
11. Pioneer Electric
12. South Alabama Electric
13. Southern Pine Electric
14. Tallapoosa River Electric
15. West Florida Electric
16. Wiregrass Electric

Municipal

1. City of Andalusia
2. City of Brundidge
3. City of Elba
4. City of Opp

Industrial

1. Micolas Mill
2. Opp Mill

Appendix A.3

EPRI CAES STUDIES

For completeness, this Appendix provides a bibliography of EPRI reports useful to those who wish to become more familiar with CAES technology.

<u>1991</u>

GS-7453 Compressed Air Storage with Humidification (CASH) Coal Gasification Power Plant Investigation, Energy Storage and Power Consultants, Inc., August 1991 (RP2834-01)

<u>1990</u>

GS-6620-Vol. 1 Compressed-Air Energy Storage Using Hard-Rock Geology: Test Facility and Results, Test Results, The Société Electrique de l 'Our S. A. Luxembourg, January 1990 (RP1791-13)

GS-6620-Vol. 2 Compressed-Air Energy Storage Using Hard-Rock Geology: Test Facility and Results, Evaluation of Test Results, The Société Electrique de l 'Our S. A. Luxembourg, January 1990 (RP1791-13)

GS-6646 Strategic Assessment of Storage Plants, Economic Studies: Benefits Under a Regulated Versus Deregulated Utility, Polydyne, Inc., January 1990 (RP128-15)

GS-6671 Compressed-Air Energy Storage Field Test Using the Aquifer at Pittsfield, Illinois, PB-KBB, Inc., February 1990 (RP1791-15)

GS-6688 Compressed-Air Energy Storage: Pittsfield Aquifer Field Test Data: Engineering Analysis and Evaluation, ANR Storage Company, February 1990 (RP2488-10)

GS-6784 Compressed Air Storage for Electric Power Generation, University of Michigan, February 1990 (RP2488-10)

GS-6987 CAES Plant with Steam Generation: Preliminary Design and Cost Analysis. Energy Storage and Power Consultants, October 1990 (RP2676-03)

GS-7070 User's Guide to DYNASTORE: A Computer Model for Quantifying Dynamic Energy Storage Benefits, Electric Power Consulting, Inc., December 1990 (RP3116-01)

1989

GS-6491 Use of Coal Gasification in Compressed-Air Energy Storage Systems, Energy Storage & Power Consultants, September 1989 (RP2999-02 Final Report)

GS-6571 Recuperators for Compressed-Air Energy Storage Plants, Gibbs & Hill, Inc., December 1989 (RP2676-01 Final Report)

1988

AP-5689 Low-Porosity Rock Cavern Design Concepts for Compressed-Air Energy Storage, Lindblom, Elf E., March 1988 (RP2488-06 Final Report)

AP-5717 Evaluation of Hard-Rock-Cavern Construction Methods for Compressed-Air Energy Storage, Fenix & Scisson, Inc., April 1988 (RP2488-11 Final Report)

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Appendix A.4

PERMITS, NOTICES, AND LETTERS

The Alabama Department of Environmental Management (ADEM) issued Air Permits and a National Pollutant Discharge Elimination System Permit. ADEM also determined that Olin Corporation's Underground Injection Control Permit could be utilized for construction of the new storage caverns because Olin would maintain sufficient control of construction details and leaching programs to ensure compliance with the permit.

The Air Permit was originally issued for two 50-MW units and was later reissued for one 100-MW unit. The Air Permits and associated letters are included below (see pp. A.4-2 to A.4-13). The letter for the draft of the National Pollutant Discharge Elimination System Permit is included (see p. A.4-14). Letters of explanation and confirmation to use the Olin Permit for Well Development are included (see pp. A.4-15 to A.4-17).

Additional considerations were impact of regulated wetlands, cultural resources, Fish and Wild Life Coordination Act, Endangered Species Act, and impact on prime farmland. Letters from the governing agencies are included (see pp. A.4-18 to A.4-22).

Notices and a news release were published to inform the public of the intent to construct a CAES Plant. These items were notice in the Federal Register (see p. A.4-23), legal notice published in the Chatom, Alabama Call-News Dispatch (see p. A.4-24), notice published by the U.S. Department of Agriculture, Rural Electrification Administration, in the Hattiesburg American (see p. A.4-25), and a news release published by the Call-News Dispatch (see p. A.4-26).

ADEM

ALABAMA
DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

Guy Hunt
Governor

Leigh Pegues, Director

1751 Federal Drive
Montgomery, AL
36130
205/271-7700

Field Offices:

Unit 806, Building 8
225 Oxmoor Circle
Birmingham, AL
35209
205/942-6168

P.O. Box 953
Decatur, AL
35602
205/353-1713

2204 Perimeter Road
Mobile, AL
36615
205/479-2336

January 29, 1987

Mr. Mike Noel
Environmental Engineer
Alabama Electric Cooperative, Inc.
P. O. Box 550
Andalusia, AL 36420

Dear Mr. Noel:

Re: Facility No. 108-0012

The enclosed Air Permits are issued pursuant to the Department's air pollution control rules and regulations. Please note the conditions which must be observed in order to retain these permits.

New sources of air pollution receiving approval by an Air Permit must notify the Chief of the Air Division upon completion of construction and prior to the planned operation. Authorization to operate must then be received from the Chief of the Air Division. Failure to notify the Chief of the Air Division upon completion of construction and/or operation without authorization can result in revocation of the Air Permit.

If you have questions or require clarification of permit conditions, please write or call Bob Cowne at 271-7861 in Montgomery.

Sincerely,

Richard E. Grusnick, Chief
Air Division

REG/BC:um

Enc.

ADEM

ALABAMA
DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

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1751 Federal Drive
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205/271-7700

Field Offices:

Unit 806, Building 8
225 Oxmoor Circle
Birmingham, AL
35209
205/942-6168

P.O. Box 953
Decatur, AL
35602
205/353-1713

2204 Perimeter Road
Mobile, AL
36615
205/479-2336

July 28, 1989

Mr. Mike Noel
Environmental Engineer
Alabama Electric Cooperative, Inc.
P. O. Box 550
Andalusia, AL 36420

Dear Mr. Noel:

RE: Facility No. 108-0012

The enclosed Air Permit is issued pursuant to the Department's air pollution control rules and regulations as a replacement for Permit Nos. 108-0012-X001 and X002. Please return the original copies of Permit Nos. 108-0012-X001 and X002. Please also note the conditions which must be observed in order to retain this permit.

New sources of air pollution receiving approval by an Air Permit must notify the Chief of the Air Division upon completion of construction and prior to the planned operation. Authorization to operate must then be received from the Chief of the Air Division. Failure to notify the Chief of the Air Division upon completion of construction and/or operation without authorization can result in revocation of the Air Permit.

If you have any questions or require clarification of permit conditions, please write or call Nate Hartman at (205) 271-7861 in Montgomery.

Sincerely,

Richard E. Grusnick, Chief
Air Division

REG/NH:cbd

Enclosure

ADEM

ALABAMA
DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

AIR PERMIT

PERMITTEE: ALABAMA ELECTRIC COOPERATIVE, INC.

LOCATION: MCINTOSH, ALABAMA

PERMIT NUMBER	DESCRIPTION OF EQUIPMENT, ARTICLE OR DEVICE
108-0012-X003	110 MW Compressed Air Energy Storage Gas Turbine

In accordance with and subject to the provisions of the Alabama Air Pollution Control Act of 1971, as amended, **Code of Alabama 1975**, *§§ 22-28-1 to 22-28-23 (the "AAPCA") and the Alabama Environmental Management Act, as amended,* **Code of Alabama 1975**, *§§ 22-22A-1 to 22-22A-15, and rules and regulations adopted thereunder, and subject further to the conditions set forth in this permit, the Permittee is hereby authorized to construct, install and use the equipment, device or other article described above.*

ISSUANCE DATE: July 28, 1989

Leigh Pegues

Alabama Department of Environmental Management

ALABAMA ELECTRIC COOPERATIVE, INC.

Permit No. 108-0012-X003

1. This permit is issued on the basis of Rules and Regulations existing on the date of issuance. In the event additional Rules and Regulations are adopted, it shall be the permit holder's responsibility to comply with such rules.

2. This permit is not transferable. Upon sale or legal transfer, the new owner or operator must apply for a permit within 30 days.

3. A new permit application must be made for new sources, replacements, alterations or design changes which may result in the issuance of, or an increase in the issuance of, air contaminants, or the use of which may eliminate or reduce or control the issuance of air contaminants.

4. Each point of emission will be provided with sampling ports, ladders, platforms, and other safety equipment to facilitate testing performed in accordance with procedures established by Part 60 of Title 40 of the Code of Federal Regulations, as the same may be amended or revised.

5. In the event there is a breakdown of equipment in such a manner as to cause increased emission of air contaminants for a period greater than 3 hours, the person responsible for such equipment shall notify the Department within an additional 24 hours and provide a statement giving all pertinent facts, including the duration of the breakdown. The Department shall be notified when the breakdown has been corrected.

6. All air pollution control devices and capture systems for which this permit is issued shall be maintained and operated at all times in a manner so as to minimize the emissions of air contaminants. Procedures for ensuring that the above equipment is properly operated and maintained so as to minimize the emission of air contaminants shall be established.

7. This permit expires and the application is cancelled if construction has not begun within 24 months of the date of issuance of the permit.

8. On completion of construction of the device for which this permit is issued, notification of the fact is to be given to the Chief of the Air Division at least 10 days in advance of planned operation of the unit. Authorization to operate the unit must be received from the Chief of the Air Division. Failure to notify the Chief of the Air Division of completion of construction and/or operation without authorization could result in revocation of this permit.

9. Prior to a date to be specified by the Chief of the Air Division in the authorization to operate, emission tests are to be conducted by persons familiar with and using the EPA Sampling Train and Test Procedure as described in the Code of Federal Regulations, Title 40, Part 60, for the following pollutants. Written tests results are to be reported to the Department within 15 working days of completion of testing.

Particulates	( )	Carbon Monoxide	( )
Sulfur Dioxide	( )	Nitrogen Oxides	(X)
Volatile Organic Compounds	( )		

10. Submission of other reports regarding monitoring records, fuel analyses, operating rates, and equipment malfunctions may be required as authorized in the Department's air pollution control rules and regulations. The Department may require stack emission testing at any time.

11. Additions and revisions to the conditions of this Permit will be made, if necessary, to ensure that the Department's air pollution control rules and regulations are not violated.

12. Nothing in this permit or conditions thereto shall negate any authority granted to the Department pursuant to the Alabama Environmental Management Act or regulations issued thereunder.

13. The Department must be notified in writing at least 10 working days in advance of all emission tests to be conducted and submitted as proof of compliance with the Department's air pollution control rules and regulations.

    To avoid problems concerning testing methods and procedures, the following shall be included with the notification letter:

    (1) The date the test crew is expected to arrive, the date and time anticipated of the start of the first run, how many and which sources are to be tested, and the names of the persons and/or testing company that will conduct the tests.

    (2) A complete description of each sampling train to be used, including type of media used in determining gas stream components, type of probe lining, type of filter media, and probe cleaning method and solvent to be used (if test procedure requires probe cleaning).

    (3) A description of the process(es) to be tested, including the feed rate, any operating parameter used to control or influence the operations, and the rated capacity.

    (4) A sketch or sketches showing sampling point locations and their relative positions to the nearest upstream and downstream gas flow disturbances.

    A pretest meeting may be held at the request of the source owner or the Department. The necessity for such a meeting and the required attendees will be determined on a case-by-case basis.

    All test reports must be submitted to the Department within 15 days of the actual completion of the test, unless an extension of time is specifically approved by the Department.

14. Only natural gas or No. 2 fuel oil will be burned in this turbine.

15. No more than 200,000 Mw hours of electricity may be generated by this source during any consecutive twelve-month period and no more than 20,000 Mw hours may be generated during this period while the turbine is burning No. 2 fuel oil. Records to document compliance with this proviso will be maintained in a form suitable for inspection for a period of at least two years.

16. The turbine will not discharge any gases into the atmosphere which contain nitrogen oxides in excess of 126 parts per million when burning natural gas and 181 parts per million when burning No. 2 fuel oil, as determined by 40 CFR Part 60 (7-1-88 Edition) Method 20.

July 28, 1989
Date

CALCULATIONS

Alabama Electric Cooperative, Inc.
108-0012

Total Expected Emissions for 2-50 MW Units: (Attachment 3)

Particulates: 6.22 TPY
SO_2: 20.20 TPY
NO_x: 122.24 TPY
CO: 45.54 TPY
VOC: 3.76 TPY

Total Expected Emissions for 1-110 MW Unit:

Given:

Takes 4500 BTU to produce 1 kw hour

200,000 MWH per year generation limit

$\frac{200,000}{110}$ = 1818 hours - 1636 on natural gas; 182 on fuel oil.

$\frac{1636}{2000} = 0.818$

$\frac{182}{2000} = 0.091$

$\frac{4500 \text{ BTU}}{\text{KWH}} \times 110,000 \text{ kw} = 495,000,000 \text{ BTU/hr}$

$\frac{495,000,000 \text{ BTU}}{\text{hr}} \times \frac{1 \text{ft}^3 \text{gas}}{1050 \text{ BTU}} = 471,429 \text{ ft}^3\text{/hr}$

$\frac{495,000,000 \text{ BTU}}{\text{hr}} \times \frac{1 \text{ gal fuel oil}}{133,300 \text{ BTU}} = 3714 \text{ gallons/hr}$

Emission Factors (Industrial Turbines): (Attachment 3)

Natural Gas:

Particulates - 14 $lbs/10^6$ ft^3
SO_x - 0.6 $lbs/10^6$ ft^3
NO_x - 300 $lbs/10^6$ ft^3
CO - 120 $lbs/10^6$ ft^3
VOC - 6.9 $lbs/10^6$ ft^3
Benzene - 1.18% of VOC emitted

Fuel Oil:

Particulates	-	5.0 lbs/10^3 gallons
SO_x	-	140(S) lbs/10^3 gallons
NO_x	-	67.8 lbs/10^3 gallons
CO	-	15.4 lbs/10^3 gallons
VOC	-	4.77 lbs/10^3 gallons
Arsenic	-	4.2 lbs/10^{12} BTU
Beryllium	-	2.5 lbs/10^{12} BTU
Cadmium	-	10.5 lbs/10^{12} BTU
Chromium	-	48 lbs/10^{12} BTU
Copper	-	280 lbs/10^{12} BTU
Mercury	-	3.0 lbs/10^{12} BTU
Manganese	-	14 lbs/10^{12} BTU
Nickel	-	170 lbs/10^{12} BTU
POM	-	22.5 lbs/10^{12} BTU
Formaldehyde	-	405 lbs/10^{12} BTU
H_2SO_4 Mist	-	39309(S) lbs/10^{12} BTU

Natural Gas Emissions:

Particulates	-	.471429 x 14 = 6.6 lbs/hr x 0.818 = 5.4 TPY
SO_x	-	.471429 x 0.6 = 0.28 lbs/hr x 0.818 = 0.23 TPY
NO_x	-	.471429 x 300 = 141.4 lbs/hr x 0.818 = 115.7 TPY
CO	-	.471429 x 120 = 56.57 lbs/hr x 0.818 = 46.3 TPY
VOC	-	.471429 x 6.9 = 3.25 lbs/hr x 0.818 = 2.66 TPY
Benzene	-	.0118 x 3.25 = 0.04 lbs/hr x 0.818 = 0.03 TPY

Fuel Oil Emissions:

Particulates	-	5 x 3.714 = 18.6 lbs/hr x 0.091 = 1.7 TPY
SO_x	-	140(.5) x 3.714 = 260 lbs/hr x 0.091 = 23.7 TPY
NO_x	-	67.8 x 3.714 = 252 lbs/hr x 0.091 = 23 TPY
VOC	-	4.77 x 3.714 = 17.7 lbs/hr x 0.091 = 1.6 TPY
CO	-	15.4 x 3.714 = 57.2 lbs/hr x 0.091 = 5.2 TPY
Arsenic	-	4.2 x 0.000495 = 0.002 lbs/hr x 0.091 = 0.0002 TPY
Beryllium	-	2.5 x 0.000495 = 0.001 lbs/hr x 0.091 = 0.0001 TPY
Cadmium	-	10.5 x 0.000495 = 0.005 lbs/hr x 0.091 = 0.0005 TPY
Chromium	-	48 x 0.000495 = 0.02 lbs/hr x 0.091 = 0.002 TPY
Copper	-	280 x 0.000495 = 0.14 lbs/hr x 0.091 = 0.013 TPY
Mercury	-	3 x 0.000495 = 0.001 lbs/hr x 0.091 = 0.0001 TPY
Manganese	-	14 x 0.000495 = 0.006 lbs/hr x 0.091 = 0.0006 TPY
Nickel	-	170 x 0.000495 = 0.08 lbs/hr x 0.091 = 0.007 TPY
POM	-	22.5 x 0.000495 = 0.01 lbs/hr x 0.091 = 0.001 TPY
Formaldehyde	-	405 x 0.000495 = 0.2 lbs/hr x 0.091 = 0.02 TPY
H_2SO_4 Mist	-	39305(0.5) x 0.000495 = 9.73 lbs/hr x 0.091 = 0.89 TPY

Total Emissions:

Particulates	-	5.41 + 1.7 = 7.1 TPY
SO_x	-	0.23 + 23.7 = 23.93 TPY

NO_x	-	115.7 + 23 = 138.7 TPY
VOC	-	2.66 + 1.6 = 4.26 TPY
CO	-	46.3 + 5.2 = 51.5 TPY
Benzene	-	0.03 TPY
Arsenic	-	0.0002 TPY
Beryllium	-	0.0001 TPY
Cadmium	-	0.0005 TPY
Chromium	-	0.0002 TPY
Copper	-	0.013 TPY
Mercury	-	0.0001 TPY
Manganese	-	0.0006 TPY
Nickel	-	0.007 TPY
POM	-	0.001 TPY
Formaldehyde	-	0.02 TPY
H_2SO_4 Mist	-	0.009 TPY

Emissions Increase:

Particulates	-	7.11 - 6.22 = 0.88 TPY
SO_x	-	23.93 - 20.20 = 3.73 TPY
NO_x	-	138.7 - 122.24 = 16.46 TPY
VOC	-	4.26 - 3.76 = 0.5 TPY
CO	-	51.5 - 45.54 = 5.96 TPY

Allowable Emissions: 40 CFR Part 60 Subpart GG

NO_x:

$$STD = 0.0075 \frac{(14.4)}{(Y)} + F$$

Where:

STD = Allowable NO_x emissions (percent by volume at 15% oxygen and on a dry basis).

Y = Manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour).

F = NO_2 emission allowance for fuel bound nitrogen

Unit Heat Input:

$$\frac{4500 \text{ BTU}}{\text{kw hr}} \times 110{,}000 \text{ kw} = 495{,}000{,}000 \text{ BTU/hr}$$

$$\frac{495{,}000{,}000 \text{ BTU}}{\text{hr}} \times \frac{1.055 \text{ kilojoules}}{1 \text{ BTU}} = 522.22 \times 10^6 \text{ kilojoules/hr}$$

Unit Procedures 110 MW

110 MW = 110 x 10^6 watts

$$Y = \frac{522.22 \times 10^6 \text{ kilojoules/hr}}{110 \times 10^6 \text{ watts}} = 4.75 \text{ kilojoules/watt hr}$$

AEC does not claim an allowance for fuel bound nitrogen

$\therefore$ F = 0

$$\text{STD } 0.0075 \times \frac{14.4}{4.75} + 0 = 0.227\% \text{ or } 227 \text{ ppm}$$

$$227 \text{ ppm } NO_x = \frac{1848 \text{ ug/m}^{3*}}{1 \text{ ppm } NO_x} \times \frac{1 \text{ gram}}{10^6 \text{ug}} \times \frac{1\#}{453.69 \text{ g}} \times \frac{0.0283 M^3}{1 \text{ ft}^3} \times \frac{288{,}411 \text{ ft}^3}{\text{min.}} \times \frac{60 \text{ min.}}{1 \text{ hr}}$$

$$= 227 \text{ ppm } NO_x \,(1.994767)$$

$$= 453 \text{ lb } NO_x/\text{hr}$$

$$\text{Flow Rate} = \frac{60 \text{ ft}}{\text{sec.}} \times 3.14 \left(\frac{12}{2}\right)^2 \times \frac{60 \text{ sec}}{\text{min}} \times 0.708725^{**} = 288411 \text{ ft}^3/\text{min.}$$

* at 68°F

$$^{**}\; V_1 = V_o \times \frac{460 + 68}{460 + 285} = V_o(0.708725)$$

<u>Expected Emissions</u> - AEC Submittal

$\frac{2.3 \text{ lb}}{\text{MWH}}$ x 110 MW = 253 lb/hr burning gas

$\frac{3.3 \text{ lb}}{\text{MWH}}$ x 110 MW = 363 lb/hr burning oil

253 x 0.818 = 207 TPY
363 x 0.091 = 33 TPY
TOTAL = 240 TPY

These emissions of NO_x are greater than AP-42 valves, but less than NSPS standard and combined emissions are less than the 250 TPY threshold

For permit purposes:

253 lb/hr = 126 ppm
363 lb/hr = 181 ppm

ADEM

ALABAMA
DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

Guy Hunt
Governor

January 29, 1987

eigh Pegues, Director

751 Federal Drive
lontgomery, AL
6130
05/271-7700

eld Offices:

nit 806, Building 8
25 Oxmoor Circle
irmingham, AL
5209
05/942-6168

O. Box 953
ecatur, AL
5602
05/353-1713

204 Perimeter Road
obile, AL
5615
05/479-2336

Mr. Mike Noel
Environmental Engineer
Alabama Electric Cooperative, Inc.
P.O. Box 550
Andalusia, AL 36420

Dear Mr. Noel:

A PTMAX dispersion model was run with the parameters furnished for the NO_x emissions from the two gas turbines at AEC's proposed Compressed Air Energy Storage (CAES) facility in McIntosh. The results showed that minimum stack heights of 75 feet can be utilized without exceeding ambient standards or toxic emission criteria.

If you have any questions concerning this, please contact me.

Sincerely,

Bob Cowne

Bob Cowne
Engineering Services Branch
Air Division

BC:dm

ADEM

ALABAMA
DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

Guy Hunt
Governor

Leigh Pegues, Director

1751 Federal Drive
Montgomery, AL
36130
205/271-7700

Field Offices:

Unit 806, Building 8
225 Oxmoor Circle
Birmingham, AL
35209
205/942-6168

P.O. Box 953
Decatur, AL
35602
205/353-1713

2204 Perimeter Road
Mobile, AL
36615
205/479-2336

February 10, 1987

Mr. Mike Noel
Environmental Engineer
Ala Electric Cooperative
P O Box 550
Andalusia, AL 36420

Dear Mr. Noel:

RE: NPDES PERMIT NO. AL0054950
McIntosh CAES Plant

We are transmitting herein a preliminary draft of the above-referenced permit.

Please note that we have not as yet run the water quality model to determine the allowable DSN001C BOD_5 levels, thus they are blank. As soon as the model is complete, we will forward the results to you.

Should you have any questions please contact the undersigned.

Sincerely,

James P. Martin

James P. Martin, P.E.
Industrial Branch
Water Division

JPM/jd

Enclosure

Olin CHEMICALS

McINTOSH PLANT — McINTOSH, ALABAMA 36553 (205) 944-2231

October 7, 1986

Mr. John Poole
Alabama Department of Environmental Management
1751 Federal Drive
Montgomery, AL 36130

Dear Mr. Poole:

In order to clarify the operational responsibility question raised in your letter dated September 4, 1986, the following is submitted:

Olin will retain surface ownership, will retain exclusive salt mining rights presently owned, and will retain exclusive cavity storage rights. The plan is to lease the surface, license construction of, and license storage use of cavities to AEC under contract terms which give Olin not only sufficient operational controls, but also sufficient control of construction details and leaching programs to protect plant interests and insure compliance with the existing UIC Permit. The contract is being written so that all cavity development activities will be undertaken or approved by Olin. This includes design of well and casing program, drilling program, and leaching program.

During cavity development, Olin will supply injection water (presently being injected into wells 7, 8 & 9), will use brine produced during creation of a salt cavity as raw material, and will be in total control of this aspect of the project. Design is to be such that Olins total process brine requirments will be used in cavity development. Since plant chlorine-caustic production is totally dependent upon this brine flow, it is imperative that Olin control this aspect of the project. Although Olin will retain total control, intentions are that due to manpower limitations, AEC may be required by Olin to observe, record and report well head pressure readings and to verify flows indicated on instrumentation located at the well head of the well being developed. The data will then be analyzed by Olin and Olin will make any needed flow adjustments at Olins pumps and/or valving, and make the required UIC reports.

> It is intended that when cavity development and brine evacuation is complete, Olin will relinquish controls it has exercised to protect the present day-to-day operations and those required to meet the existing UIC Permit. AEC will then operate under a Class V Permit requested by and issued to AEC. Olin then will contractually require only controls which will protect company long term interests and contractual obligations to subsurface owners.

In summary, it is believed operational control Olin will exert during cavity development allows well construction and cavity development to be undertaken under the existing UIC Permit. Further, it is believed Olin will not retain sufficient operational controls during air storage and generation to allow application for a Class V Permit to be made in its name. At this time AEC would become responsible for the required permits.

Would you verify that, under the listed conditions, the planned cavities can be constructed, leached, and operated as stated? Your response to this request is very much appreciated.

Sincerely,

W J Derocher

W. J. Derocher
Plant Manager

JWF/~~TBO~~ JBO/WJD:js

bc: A. Feldman
J. Fleming
F. Champion
J. Rytlewski

ADEM

ALABAMA
DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

George C. Wallace
Governor

1751 Federal Drive
Montgomery, AL
36130
205/271-7700

Field Offices:

Unit 806, Building 8
225 Oxmoor Circle
Birmingham, AL
35209
205/942-6168

P.O. Box 953
Decatur, AL
35602
205/353-1713

2204 Perimeter Road
Mobile, AL
36615
*5/479-2336

October 27, 1986

Mr. William J. Derocher
Plant Manager
Olin Corporation
P.O. Box 28
McIntosh, AL 36553

Dear Mr. Derocher:

Based on the information submitted to the Department, it has been determined that the new well proposed to be developed by Olin Corporation is covered under the present Class III UIC Permit Number ALSI4065010.

Sincerely,

Laura Ming

Laura E. Ming
Engineer
Groundwater Section
Water Division

LEM/vrh

DEPARTMENT OF THE ARMY
MOBILE DISTRICT, CORPS OF ENGINEERS
P.O. BOX 2288
MOBILE, ALABAMA 36628-0001
October 20, 1986

REPLY TO
ATTENTION OF:

Regulatory Branch

SUBJECT: Department of the Army Regulatory Requirements - Jurisdictional Determination Number ALJ86-00439-S

Mr. Mike Noel
Alabama Electric Cooperative, Inc.
Post Office Box 550
Andalusia, Alabama 36420

Dear Mr. Noel:

On October 15, 1986, Mr. David Schwartz met with Mr. Mikell Speaks at the site of your proposed compressed air energy storage plant near Bilbo Creek, community of McIntosh, Washington County, Alabama.

Mr. Schwartz and Mr. Speaks, utilizing the recently completed site survey, determined that no regulated wetlands will be impacted by your proposed facility; therefore, a Department of the Army permit will not be required.

If further clarification is required, feel free to contact Mr. Schwartz at (205) 694-3780.

Sincerely,

Ronald A. Krizman
Chief, Regulatory Branch
Operations Division

Copy Furnished:

Mr. Mikell Speaks
Mikell D. Speaks & Associates
Consulting Engineers Incorporated
732 Oak Circle Drive West
Mobile, Alabama 36609

F. LAWERENCE OAKS
EXECUTIVE DIRECTOR

STATE OF ALABAMA
ALABAMA HISTORICAL COMMISSION
725 MONROE STREET
MONTGOMERY, ALABAMA 36130-5101

TELEPHONE NUMBER
261-3184

July 17, 1986

Mr. Mike Noel
Alabama Electric Cooperative, Inc.
Post Office Box 550
Andalusia, AL 36420

RE: Proposed Compressed Air
Energy Storage Facility
Washington County, AL

Dear Mr. Noel:

Our files indicate that there are no known cultural resources within the above referenced project area. However, the specific location has never been surveyed for cultural resources and it is unknown if sites potentially eligible for the National Register of Historic Places exist here. The project area is similar environmentally to areas nearby which are known to have significant cultural resources. Therefore, it must be considered archaeologically sensitive.

The Alabama Historical Commission requests that the project area be surveyed by a professional archaeologist. The archaeologist's report should be submitted to our office for review and concurrence prior to any construction activities.

Should you have any questions, direct written inquiries to Greg Rhinehart at this office.

Sincerely,

F. Lawerence Oaks

F. Lawerence Oaks
State Historic Preservation Officer

FLO/GCR/cs

United States Department of the Interior

FISH AND WILDLIFE SERVICE

P.O. Drawer 1190
Daphne AL 36526

July 18, 1986

Mr. Mike Noel
Alabama Electric Cooperative, Inc.
P.O. Box 550
Andalusia, Alabama 36420

Dear Mr. Noel:

This responds to your letter dated July 11, 1986, regarding a proposed compressed air energy storage (CAES) plant in Washington County, Alabama. We have reviewed the information provided and have the following comments in accordance with requirements of the Fish and Wildlife Coordination Act (48 Stat. 401, as amended; 16 U.S.C. et seq.) and the Endangered Species Act (87 Stat. 884, as amended; 16 U.S.C. 1531 et seq.).

A. Fish and Wildlife Coordination Act

As indicated in the provided topographic map and alluded to in your letter, the proposed plant site abuts an extensive tract of forested wetlands along Bilbo Creek. Since AEC is not planning to dredge or fill these wetlands, we do not expect project impacts to be significant. However, considering the nearness of the wetlands to the proposed plant site, we recommend AEC ask the Corps of Engineers to conduct a field inspection to delineate the jurisdictional wetland line. A buffer zone (at least 100 ft.) should then be established between the wetlands and the construction site. Such information would also be beneficial if future plant expansion is proposed. We would oppose any expansion into the wetlands.

If you require further information regarding our concerns for the protection of fish and wildlife habitat, contact our Ecological Services field office at P.O. Drawer 1190, Daphne, Alabama 36526. (Phone 205/690-2181).

B. Endangered Species Act

Our records indicate no endangered, threatened or proposed species, or their critical habitat occurring in the project area. Therefore, no further endangered species consultation will be required for this project, as currently described.

If you anticipate any changes in the scope or location of this project, please contact our Endangered Species office for further coordination. (Phone: 601/960-4900). Their mailing address is U.S. Fish and Wildlife Service, 300 Woodrow Wilson Avenue, Suite 316, Jackson, MS 39213.

Sincerely yours,

Larry E. Goldman
Field Supervisor

cc: SE, Jackson, MS
ADCNR, Montgomery, AL

United States
Department of
Agriculture

Soil
Conservation
Service
P.O. Box 446
Chatom, AL 36518
Phone 847-2292

Subject: Prime Farmland Determination

Date: July 29, 1986

To: Mr. Mike Noel
Environmental Engineer
Alabama Electric Cooperative, Inc.
Post Office Box 550
Andalusia, Alabama 36420

430-13-11

Dear Mr. Noel:

The area in Washington County that you requested a prime farmland determination has approximately 7 acres of soil mapped 245 A (map symbol) Escambia - fine sandy loam, 0 to 2 percent slopes which is considered prime farmland soil, however this location should have no adverse affect on prime farmland in Washington County.

Enclosed is your topographic map of proposed location, photo copy of soil map with prime farmland legend and copy of soil scientist letter.

Please let me know if any additional assistance is needed to assist you with this project.

Sincerely,

Carl Pennington

Carl Pennington
District Conservationist

Enclosure

Notices

Federal Register
Vol. 51, No. 239
Friday, December 12, 1986

This section of the FEDERAL REGISTER contains documents other than rules or proposed rules that are applicable to the public. Notices of hearings and investigations, committee meetings, agency decisions and rulings, delegations of authority, filing of petitions and applications and agency statements of organization and functions are examples of documents appearing in this section.

DEPARTMENT OF AGRICULTURE

Rural Electrification Administration

Intent To Conduct Public Scoping Meetings and Prepare a Draft Environmental Impact Statement for a Proposed Compressed Air Energy Storage Project

AGENCY: Rural Electrification Administration.

ACTION: Notice of intent to conduct public scoping meetings and prepare a draft enviromental impact statement.

SUMMARY: The Rural Electrification Administration (REA) intends to conduct public scoping meetings to assess the environmental impacts of the potential construction of a 100 MW Compressed Air Energy Storage (CAES) generating facility in Washington County, Alabama, or Forest County, Mississippi, by Alabama Electric Cooperative Inc. (AEC), P.O. Box 550, Andalusia, Alabama 36420.

Meetings Schedule—REA will conduct public scoping meetings as below:

—Wednesday, January 14, 1987, at the Jackie Sherrill Community Center on Front Street in Hattiesburg, Mississippi, at 7:30 p.m.

—Thursday, January 15, 1987, at the Town Hall in McIntosh, Alabama, at 7:30 p.m.

ADDRESS: All interested parties are invited to submit written comments to REA prior to, at, or within 30 days after scoping meetings, in order for the comments to be part of the formal record. Comments may be submitted to Mr. Frank W. Bennett, Director, Southeast Area—Electric, REA, U.S. Department of Agriculture, Washington, DC 20250, or delivered to the REA representative conducting the scoping meetings.

FOR FURTHER INFORMATION CONTACT: Mr. Alexander Sherman, Chief, Distribution and Transmission Engineering Branch, Southeast Area—Electric, U.S. Department of Agriculture, Washington, DC 20250 or Mr. Ray Clausen, Manager, Engineering & Operation Division, Alabama Electric Cooperative, Inc., P.O. Box 550, Andalusia, Alabama 36420.

SUPPLEMENTARY INFORMATION: REA has scheduled these meetings, in order to meet its requirements under the National Environmental Policy Act of 1969, the Council on Environmental Quality Guidelines (40 CFR Part 1500) and REA Environmental Policies and Procedures (17 CFR Part 1794). Depending upon information received at these meetings, together with information obtained from public agencies and from special studies, REA will determine if an Environmental Impact Statement or an Environmental Assessment is required to complete its environmental responsibilities under 7 CFR Part 1794.

The sites are being considered for a proposed 100 MW CAES facility. The complete system components include combustion turbines, a motor-generator, an air compression system, an underground air storage cavern, transmission facilities and related auxiliary equipment. Alternatives to be considered include: (1) No action, (2) load management, (3) purchase power from other utilities, and (4) other type or generation facilities.

The public scoping meetings, to be conducted by a representative of REA, will be held to solicit public input and comments including any significant issues and environmental concerns. These concerns should relate to the impacts of the proposed project, its possible location and alternatives. Requests for additional information concerning the scoping meetings and the project may be directed to AEC at the above address.

Any REA action authorizing AEC to proceed with construction of the CAES facility will be subject to, and contingent upon, reaching satisfactory conclusions with respect to the environmental impacts and need for the project, and such action will be taken only after full compliance with REA's environmental policies and procedures.

This program is listed in the Catalog of Federal Domestic Assistance as 10.850—Rural Electrification Loans and Loan Guarantees. For the reasons set forth in the notice for the final rule related to 7 CFR Part 3015, Subpart V, this program is excluded from the scope of Executive Order 312372 which requires intergovernmental consultation with state and local officials.

Dated: December 9, 1986.

Richard A. Jones,
Acting Administrator.

[FR Doc. 86–27962 Filed 12–11–86; 8:45 am]
BILLING CODE 3410–15–M

DEPARTMENT OF COMMERCE

Office of the Secretary

[Docket No. 61099–6199]

Privacy Act of 1974; Addition of a New Location and Revision to an Existing System of Records

AGENCY: Office of the Secretary, Commerce.

ACTION: Notice: request for comments.

SUMMARY: In accordance with the requirements of the Privacy Act, this notice announces the revision of an existing system of records entitled, COMMERCE/NOAA—5, Fisheries Law Enforcement Case Files. The revision reflects two new routine uses, and provides notification of an additional location of the records.

EFFECTIVE DATE: Commerce invites interested persons to submit comments on the proposed changes. Otherwise, the revisions will be adopted without further notice January 12, 1987, unless comments are received which would result in a contrary determination.

ADDRESS: Please address or deliver written comments to the: Information Management Division, Attention: Mrs. Geraldine P. LeBoo, Office of Information Resources Management, Department of Commerce, Room 6622, Herbert C. Hoover Building, 14th and Constitution Avenue, NW., Washington, DC 20230.

FOR FURTHER INFORMATION CONTACT: Mrs. Geraldine LeBoo, Information Management Division, (202) 377–4217

SUPPLEMENTARY INFORMATION: The National Oceanic and Atmospheric Administration (NOAA), a Commerce component, has determined that an additional location of the records in this system be added. NOAA performs enforcement and investigations of

Legal Notice

DEPARTMENT OF AGRICULTURE
Rural Electrification Administration

Notice of Intent to Conduct Public Scoping Meetings and Prepare a Draft Environmental Impact Statement for a Proposed Compressed Air Energy Storage Project.

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For Further Information: A report entitled, "Alternatives Evaluation and Site Selection Study for Compressed Air Energy Storage," prepared by Alabama Electric Cooperative (AEC) is available for review at public libraries in Hattiesburg, MS, and Chatom and McIntosh, AL. Additional information is available from Mr. Mike Noel, Environmental Engineer, Alabama Electric Cooperative, P.O. Box 550, Andalusia, AL 36420 (telephone number (205) 222-2571). Alternatively, you may call Mr. Alexander Sherman, Chief of Distribution and Transmission Engineering Branch, Southeast Area Electric, U.S. Department of Agriculture, Washington, DC 20250 or Mr. Ray Clausen, Manager of Engineering and Operations Division, Alabama Electric Cooperative.

Supplementary Information: REA has scheduled these meetings in order to meet its requirements under the National Environmental Policy Act of 1969, the Council on Environmental Quality Guidelines (40 CFR Part 1500) and REA Environmental Policies and Procedures (17 CFR Part 1794). Depending upon information received at these meetings, together with information obtained from public agencies and from special studies, REA will determine if an Environmental Impact Statement or an Environmental Assessment is required to complete its environmental responsibilities under 7 CFR part 1794.

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12/25/1tc

DEPARTMENT OF AGRICULTURE
Rural Electrification Administration

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The public scoping meetings to be conducted by a representative of REA, will be held to solicit public input and comments including any significant issues and environmental concerns. These concerns should relate to the impacts of the proposed project, its possbile location and alternatives. Requests for additional information concerning the scoping meetings and the project may be directed to AEC at the above address.

Any REA action authorizing AEC to proceed with construction of the CAES facility will be subject to and contingent upon reaching satisfactory conclusions with respect to the environmental impacts and need for the project, and such action will be taken only after full compliance with REA's environmental policies and procedures.

December 29, 1986

THE CALL-NEWS DISPATCH
December 25, 1986

Meetings Called To Discuss Plans For Storage Plant

Scoping meetings to discuss plans for a proposed compressed air energy storage plant which may be constructed by Alabama Electric Cooperative are scheduled in Hattiesburg, Miss., and in McIntosh Jan. 14 - 15.

The Hattiesburg meeting is scheduled for Jan. 14 at 7:30 p.m. in Jackie Sherrill Community Center. The McIntosh meeting will be held the next night at McIntosh Town Hall at 7:30 p.m.

AEC environmental engineer Mike Noel said discussions would explain what a compressed air energy storage plant is, AEC's need for the facility, and the site selection process.

In addition, he said the general public will be given an opportunity to ask for pertinent questions and to express views concerning the potential environmental impacts of the proposed plant.

AEC, a generation and transmission cooperative, is considering construction of a compressed air energy storage plant to supplement the cooperative's other generating facilities and to provide energy during periods of high utilization.

AEC is the power supplier for 22 member systems in central and south Alabama and the panhandle of Florida.

Two potential sites for the proposed plant are being studied, one in the Petal salt dome near Petal, Miss., and another in the McIntosh salt dome near McIntosh.

The salt dome would be utilized to store air compressed by off-peak coal-fired generation. During periods when electrical consumption on the AEC system is high, the air would be released and with supplemental heat and air would operate a turbine-generator to generate electricity.

Electric Power Research Institute, founded in 1972, will contribute financial and engineering assistance to the project if it is approved. EPRI conducts a technical research and development program for the U. S. electric utility industry to improve power production, distribution and use.

AEC is one of 600 utilities who are members of EPRI. The National Rural Electric Cooperative Assn. is also involved in the project.

A compressed air energy storage facility is in operation in West Germany and two others are under construction in Italy and Russia. The proposed plant would be the first for the United States.

Appendix A.5

REFERENCES

This Appendix provides selected references useful to those who wish to become more familiar with CAES technology.

1. R. Schainker, M. Nakhamkin, "Compressed-Air Energy Storage (CAES) Overview, Performance, and Cost Data for 25-MW to 50-MW Plants," 1985.

2. Alabama Electric Cooperative, Inc., Engineering and Operation Division System Planning Department, "Alternatives Evaluation and Site-Selection Study for Compressed-Air Energy Storage" (AEC internal report), 1986.

3. Alabama Electric Cooperative, Inc., Engineering and Operations Division System Planning Department, "Environmental Analysis for the McIntosh Compressed Air Energy Storage Plant" (AEC internal report), 1987.

4. Encotech, Inc., "Recuperative Heat Exchangers in Compressed-Air Energy Storage Plants," EPRI report, EM-3843, 1985.

5. M. Nakhamkin, L. Andersson, E. Swensen, J. Howard, R. Meyer, R. Schainker, R. Pollak, and B. Mehta, "AEC 110 MW CAES Plant - Status of Project," American Power Conference, April, 1991.

6. H. Brown, J. Witt, and R. Pollak, "Compressed Air Energy Storage (CAES) RAM," ASME 89-JPGC/Pwr-9.

7. M. Nakhamkin, E. Swensen, R. Schainker, and R. Pollak, "Advanced Compressed Air Energy Storage Concepts with Utilization of the Low Pressure Expander Exhaust Gas Heat for Steam Generation," ASME 89-GT-221.

8. R. Pollak, "Status of First U.S. CAES Plant," EPRI Journal, December, 1988.

9. M. Nakhamkin, et al., "Advanced Recuperator for Compressed Air Energy Storage Plants," ASME 89-JPGC-GT-7.

10. M. Nakhamkin, et al., "CAES Plant Performance and Economics as a Function of Underground Salt Dome Storage Transient Processes," ASME 89-GT-143.

11. E. Swensen, B. Mehta, and M. Nakhamkin, "Analysis of Temperature Transients of Underground Air Storage in a Salt Dome during CAES Plant Operation," Solution Mining Research Institute, Fall Meeting, Paris, October, 1990.

Appendix A.6

GLOSSARY

AA	ambient air
ADEM	Alabama Department of Energy Management
AEC	Alabama Electric Cooperative
BBC	Brown, Boveri & Cie
B&M	Burns & McDonnell
CAES	compressed-air energy storage
C&E	construction and engineering
CFC	Cooperative Financing Corporation
CT	combustion turbine (gas turbine)
EIS	environmental impact statement
EPRI	Electric Power Research Institute
ESPC	Energy Storage & Power Consultants
FA	forced air
FOA	forced oil-to-air
FRP	fiberglass plastic
F&S	Fenix & Scisson
G&H	Gibbs & Hill
HHV	higher heating value
HVAC	heating-ventilating air-conditioning
JV	Joint Venture
KBB	Kavernen Bau-Und Betriebs-GMBH
LHV	lower heating value
MW	megawatt
NPDES	National Pollutant Discharge Elimination System
NWK	Northwestdeutche Kraftwerk
OA	oil-to-air
OD	outer diameter
QA	quality assurance
QC	quality control
REA	Rural Electrification Authority
SEPA	Southeastern Electric Power Administration
SERC	Southeastern Reliability Council

SMEPA	South Mississippi Electric Power Association
SPP	Southwest Power Pool
UE&C	United Engineers & Constructors
UIC	Underground Injection Control

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Funded through annual membership dues from some 700 member utilities, EPRI's work covers a wide range of technologies related to the generation, delivery, and use of electricity, with special attention paid to cost-effectiveness and environmental concerns.

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