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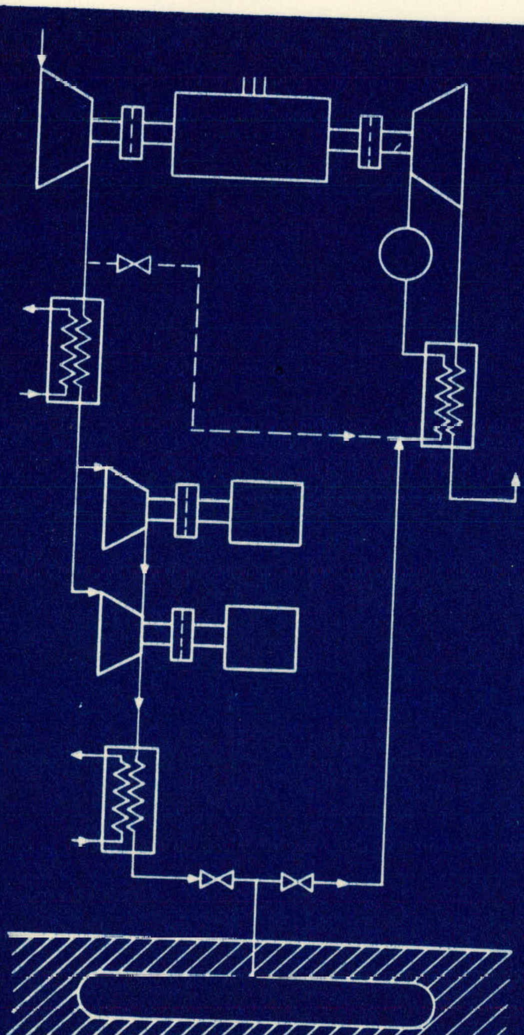
ECONOMIC AND TECHNICAL FEASIBILITY STUDY OF COMPRESSED AIR STORAGE



FINAL REPORT

Prepared for the
United States Energy Research
and Development Administration
Office of Conservation
Contract E(11-1) - 2559

GENERAL ELECTRIC

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ECONOMIC AND TECHNICAL FEASIBILITY STUDY OF COMPRESSED AIR STORAGE

March 1976

OFFICE OF CONSERVATION
U. S. ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION
WASHINGTON, D. C.

Prepared Under

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Prepared by

Advanced Energy Programs Operation
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General Electric Company
Schenectady, New York 12301

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FOREWORD

This "Economic and Technical Feasibility Study of Compressed Air Storage" is one of several studies directed toward identification and development of new energy conservation measures, which are being conducted by the United States Energy Research and Development Administration. The report contains an account of work completed under Contract E(11-1)-2550 from the Energy Research and Development Administration to the General Electric Company. The work was initiated under letter contract AT(11-1)-2559 on March 1, 1975. The following organizations and personnel contributed to the completion of this work.

General Electric Company
J.B. Bush, Jr. (Principal Investigator)
J.M. Campbell
P.M. Jarvis
E.S. Jerabek
D.A. Plionis

Fenix and Scisson, Inc.
P.A. Aamodt
R.D. Andersen
J.L. Ash
A.S. Mitchell
L.A. Rives

United Engineers and Constructors, Inc.
G.A. Englesson
E.J. Sosnowicz

The General Electric Company personnel provided overall program management and contributed to the sections dealing with the literature on compressed air storage, turbomachinery concepts, performance and economics, and the evaluation of institutional constraints. Fenix and Scisson, Inc. performed the work needed to evaluate the feasibility and economics of the underground reservoirs, as well as the geographical and geological assessments of compressed air storage. United Engineers and Constructors, Inc. contributed to the performance and cost estimates of the balance of plant, including the design of the air collection manifold.

The program was initiated under the technical supervision of:

Mr. Rufus Shivers
Division of Conservation R&T
Office of Conservation
U.S. Energy Research and Development Administration

and completed under the technical supervision of:

Dr. George C. Chang
Chief of Mechanical Energy Branch
Division of Conservation R&T
Office of Conservation
U.S. Energy Research and Development Administration

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Section 1

INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

The potential for conserving premium fuels and the economic advantages of incorporating energy storage facilities into an electric utility network have been increasingly recognized, especially as the twin pressures of shifts in fuel availability and enormous increases in capital requirements influence the generation planning by utilities. At present, pumped hydroelectric storage is the only alternative to storage of energy as chemical fuels which is now in widespread use by utilities. Siting constraints and the extensive lead-time to build facilities requiring two surface reservoirs have limited the application of this technology and encouraged the development of advanced technologies for energy storage by utilities.

A broad assessment of the technical alternatives for utility energy storage has recently been completed for the Energy Research and Development Administration and the Electric Power Research Institute. This study has concluded that in the near term a technically and economically promising technology for utility energy storage is that of using electrical energy generated by base load plants during offpeak load periods to compress air which is then stored. During peakload periods, the compressed air is heated by burning fuel in a combustion chamber, and the air and combustion products expanded through a turbine. The turbine furnishes the shaft power to a generator which provides power to an electric utility network. Figure 1-1 is a schematic outline of a compressed air energy storage (CAES) system.

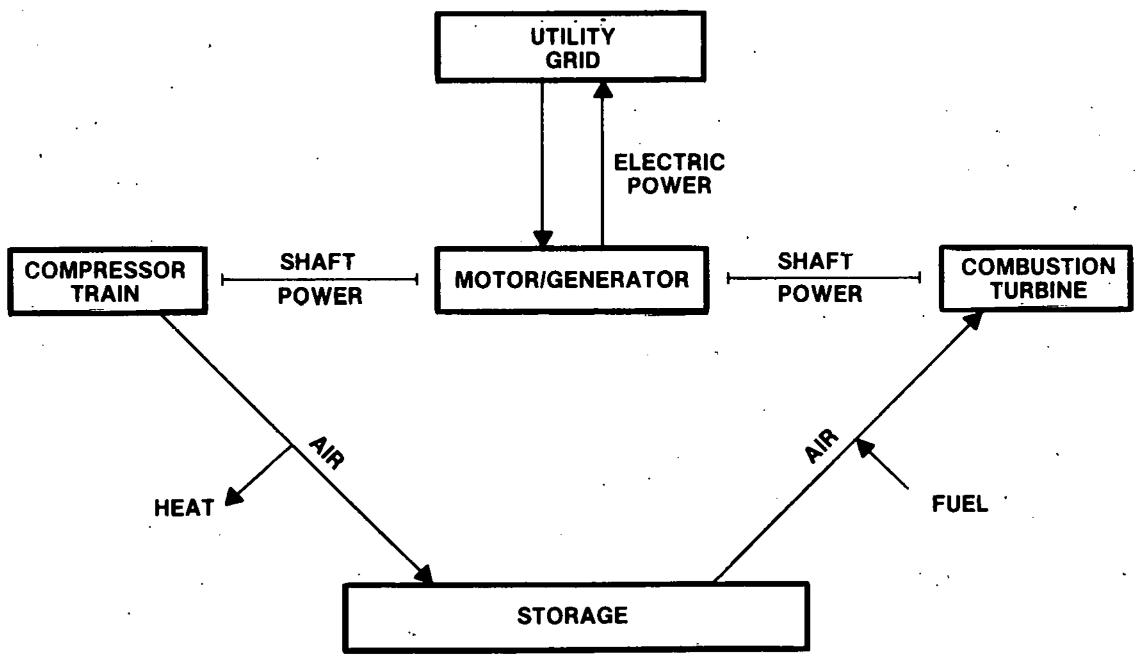

Figure 1-1. Schematic of Basic Compressed Air Cycle

1.2 SUMMARY

The results of a study of the economic and technical feasibility of compressed air storage are contained in the present report. The study, which concentrated primarily on the application of underground air storage with combustion turbines, consisted of two phases. In the first phase a general assessment of the technical alternatives, economic characteristics and the institutional constraints associated with underground storage of compressed air for utility peaking application was carried out. The goal of this assessment was to identify potential barrier problems and to define the incentive for the implementation of compressed air storage. The report of this assessment is contained in Sections 2 through 6. In the second phase, the general conclusions of the assessment were tested by carrying out the conceptual design of a CAES plant at two specific sites, and a program of further work indicated by the assessment study was formulated. The conceptual design of a CAES plant employing storage in an aquifer is contained in Section 7, while that of a plant employing storage in a conventionally excavated cavern employing a water leg to maintain constant pressure is contained in Section 8. Recommendations for further work, as well as directions of future turbomachinery development, are contained in Section 9. Details of the methods and data employed in the assessment, as well as background geological information, are contained in the Appendices. A summary of the principal conclusions follows.

TECHNICAL FEASIBILITY

There appear to be no identifiable, generally prevailing technical barriers preventing the application of CAES for energy storage by utilities. However, geological conditions at specific sites may limit or prevent the implementation of CAES at the site. There are technical areas where laboratory and field investigations are indicated to provide information needed for design of the surface plant and of the underground air reservoir. Physical and chemical characterization of material transported from the air reservoir into the turbine is needed to determine the need for a cleanup train. Investigations of the mechanical response of the host formation to the relatively rapid temperature and pressure cycling and high flow rates characteristic of a daily pumping/generation cycle are required. The work in both these areas may be carried out during the preliminary phases of the development of specific sites potentially suitable for CAES.

The major component subsystems of a CAES system are the compressor train, including inter- and after-coolers and water separators, the underground storage, the expander train which consists of regenerator(s), combustor(s) and expander turbine(s), the motor-generator and couplings, the switchyard and transformer facility, the electrical, mechanical and airflow control subsystems, and auxiliary support systems such as the fuel supply. The analysis of the turbomachinery alternatives is based on the evolutionary development of gas turbine technology from a base system representing the state-of-the-art in 1975. The heat rate for this base system, 5252 Btu/kWh

(HHV) is somewhat less than one-half that for state-of-the-art simple cycle gas turbines, 11,300 Btu/kWh. Thus, the oil or natural gas used by a base system CAES plant would be about 46 percent of that required by a simple cycle turbine plant to generate the same quantity of electrical energy.* If oil- or gas-fired plants are used to generate the electrical energy needed to compress air in the CAES plant, the amount of fuel consumed by those plants should be included in estimating the potential oil savings from the implementation of CAES. Modifications of the basic system incorporating either a high pressure combustor or a high pressure recuperator and expander were considered. The general conclusion is that for compressed air storage employing fuel-fired turbines, the basic turbomachinery technology to demonstrate the concept exists now. With a definable, and relatively low-risk development effort, it should be possible to implement a technology base for advanced systems that will show both lower generation costs and lower fuel consumption than the base case. While more detailed specification of plants adapted to specific sites will be required, no technical barriers to implementation of compressed air storage were identified arising from turbomachinery.

In addition to the two generations of compressed air energy storage turbomachinery already described, limited consideration was given to a third generation unfired turbine system. A distinguishing characteristic of this cycle is that no fuel is required during generation. Instead, a heat storage regenerator is employed to store the heat of compression and to heat the air coming out of storage during generation. A preliminary assessment indicates that sufficient economic incentive for the cycle may exist if it is possible to employ temperatures and pressures much higher than those in current compressors. The material requirements and life expectancy of such equipment needs to be established since it is far beyond the present state-of-the-art in compressors.

It is difficult to make general statements about the state of the technology of underground compressed air storage because of the determining effect that conditions at the specific site will have on the feasibility of carrying out compressed air storage at that site. The approach followed in this report is initially to summarize and compare the characteristics and distribution of rock types that are potential hosts for compressed air storage. Of these, only certain shales appear to be unsuitable either for constant volumes or constant pressure compressed air storage without extensive and costly protection of the rock surface. A number of ways for providing the storage space are considered: natural caverns, mines, conventionally mined caverns,

*The potential oil saving resulting if compressed air storage were already fully implemented for peaking in 1975 would be 67 million barrels of oil per year. This estimate is based on the difference in the present efficiency of fuel conversion for the simple cycle gas turbine relative to a base compressed air storage system, installed peaking capacity of 40,000 MW and an average 600 hrs/yr of operation.

solution mined caverns, aquifers and depleted oil and gas fields. The technical characteristics of each are considered in relation to the requirements of compressed air storage. The general conclusion is that only conventionally mined caverns, solution mined caverns or aquifers offer the potential for widespread implementation of compressed air storage. Depleted oil and gas fields however may provide a valuable guide in identifying aquifers suitable for compressed air storage. Because the technical requirements for site identification and exploration are of critical importance to the implementation of compressed air storage, they are discussed in some detail, and a format provided for identifying the appropriate technologies.

ECONOMIC FEASIBILITY

It is essential to the widespread implementation of compressed air storage not only that the technology be feasible and adaptable to the utilities' requirements, but that it meet the economic criteria utilities employ in planning expansion of their generation plant. To provide a basis for this assessment, cost estimates for the complete turbomachinery systems were made for the base system and for the second generation system with a high pressure recuperator and expander. Total costs (in 1975 dollars), including balance of plant, ranged from 110.8 to 179.8 $/kW depending on the maximum pressure and the nature of the expansion train.

The costs of the turbomachinery and of the balance of plant components can generally be based on experience with standard manufactured equipment. However, the range of uncertainty in the costs of the underground storage needed in a CAES system is much greater because the cavern design or aquifer development plan must be based on the conditions prevailing at the specific site of the plant. The costs of construction at that site can be profoundly affected not only be the geological characteristics of the host formation, but by such regional variables as labor costs, land values and the cost of disposal of waste rock or brine. In carrying out the economic assessment, a set of assumptions were made drawn from experience in the construction of conventional and solution mined caverns for hydrocarbon or gas storage, and from the experience of natural gas storage in aquifers. Employing these assumptions, generalized conceptual designs and site development plans were prepared from which storage costs were derived. Typically, storage costs ranged from $4.30/kWh to $38.20/kWh for large storage volumes. The lowest cost of storage was associated with solution mined caverns, but the lowest cost aquifer storage was only about 40 percent more costly than the lowest cost solution cavern storage. The costs derived on this basis represent a bench mark against which the costs relevant to a specific site can be measured.

From the turbomachinery, balance of plant and storage costs, investment costs for a number of CAES alternatives were calculated. When these are combined with fuel, compression energy and variable operating and maintenance costs, a total cost for generation is obtained. Two comparison years were chosen: 1975 and 1981. In the 1975 comparison, none of the CAES alternatives is economically favored over a simple cycle gas turbine plant. However, for the low pressure CAES plants employing storage in solution caverns or aquifers, a compression energy cost of $4/ MWh would favor the CAES alternatives over the S/C turbine alternative in 1975. In the 1981 comparison year, these CAES alternatives are favored over the S/C turbine plant even at compression energy costs greater than $10/ MWh and a 1981 turbine fuel cost of $3.44/ MBtu.

Thus, this economic assessment indicates that there are conditions under which CAES plants may be economically favored over S/C turbine plants to meet peak demand. These conditions are specific to particular sites, both with regard to the geology and geography of the site, and with regard to the characteristics of the utility in whose service area the site is located. The relative economic attractiveness of CAES will be enhanced relative to S/C turbines by a continuing increase in the price of turbine fuel.

INSTITUTIONAL CONSTRAINTS

There are no institutional problems that will generally limit the implementation of CAES. However, considerations such as the requirement to dispose of waste from underground construction operations or the potential for contamination of ground or surface water during operation of a CAES plant may provide constraints at specific sites. This may be particularly true for the preparation of solution mined caverns and shallow aquifers containing potable water. Local as well as State and Federal regulations must be carefully reviewed with regard to permitted uses for aquifers either as storage or as brine disposal sites. The means by which risk is allocated in carrying out underground construction presently adds to the overall cost of storage preparation and thus may be regarded as a general constraint. A number of patents, both United States and foreign, have been issued that bear on CAES. The existence of patents in force covering key aspects of one or several of the technologies, e.g., turbomachinery, or underground construction, that interact in a CAES system may act either as a constraint or an incentive to the implementation of a particular embodiment of CAES. Before the decision to build a compressed air plant of any design is made, a review on that specific embodiment should be conducted.

POTENTIAL FOR UTILITIES APPLICATION

One of the most important factors in estimating the extent to which utilities may apply CAES is that of the geography and the relationship of suitable storage sites to transmission corridors. In the case of storage in salt, using solution caverns, or conventionally mined caverns, it is possible to arrive at an estimate of the availability of sites to utilities by comparing the location of salt domes and bedded salt with the location of transmission corridors. In this way, using the 1971 figures for peak generation, it is estimated that a total of 52,185 MW is provided by utilities geographically situated to employ CAES in salt. These utilities represent 17.6 percent of the peak generation in the United States in 1971. The East Central Area Reliability Coordination Agreement Area (ECAR) is the largest single group of utilities in terms of generation capacity that potentially might employ storage in salt. Extensive application of CAES in solution mined caverns by utilities belonging to the Electric Reliability Council of Texas and the Southwest Power Pool has a significant potential. It is more difficult to estimate the potential for storage in aquifers since sites for compressed air storage in aquifers have not been identified with the precision possible for salt storage. Based on regional geology, it can be estimated that utilities serving 148,100 MW or about 50 percent of the United States peak demand in 1971, are in areas potentially suitable for aquifer storage. Because of the relatively unattractive economics of storage in mined caverns, such storage was not included in the estimate of the potential for implementation. However, particularly in the Northeastern United States, there will be sites specially suited for compressed air energy storage which should add to the extent to which CAES technology is implemented.

There are many other factors besides geography that must be considered in estimating the extent to which utilities may employ CAES. For example, the characteristics of the technology, in particular, system reliability and component availability, the environmental constraints applicable to a particular utility, the utility load characteristics, peak demand growth rate, and the availability of low cost offpeak energy will influence the utilities decision among alternatives. A particular environmental constraint, very difficult to quantify at this time, is the availability to the utility of a secure supply of oil to meet peak power demands. In the near future, at least, availability of capital provides a constraint for a number of utilities. Because of this complex of factors, there is considerable uncertainty in any estimate of the potential for the implementation of CAES. A basis for an estimate is provided by the results of studies of implementation of energy storage, in particular, batteries, in utilities generation expansion. These studies indicate that 10 to 15 percent of the generating capacity of the utility might be served by energy storage with the technology having the characteristics of CAES. Based on a peak demand growth of 6 percent per year, an incremental 1985 addition of approximately 40,000 MW of capacity can be estimated. Geographic considerations indicate that salt or aquifer storage will be available to meet 52 percent of this demand. Thus, a 1985 market of the order of 2,000 to 4,000 MW/yr of additional capacity for CAES may be estimated.

CONCEPTUAL DESIGN OF THE BROOKVILLE STATION

To test the conclusions of the general assessment, and to refine the CAES technical and economic characteristics developed in that work, a site specific conceptual design of a CAES plant was carried out. An aquifer storage plant was selected. With the substantial cooperation of the Commonwealth Edison Company, a survey of some of the potential aquifer storage sites in that utility's service area was made. A site near Brookville, Illinois, approximately 100 miles west of Chicago, was selected, and the conceptual design for a CAES plant at that site was carried out.

A plant with an ultimate generating capacity of 600 MW, a 10 hour daily generation time and a compression cycle that derives 40 percent of its energy on weekends was specified. In addition, the utility stated that it would be advantageous to achieve a close match between capacity expansion and demand growth. Increments of 150 MW with four nearly identical modular units were selected. Employing known or estimated characteristics of the formations at the Brookville site, a plant with a stable, fixed air reservoir was designed. Because the permeability of the reservoir formation is estimated to be rather low, the reservoir is expected to behave nearly as a constant volume air store, without significant water drive. The formation pressure, 240 psia, is rather low and one limiting design consideration for this site was that at its lowest pressure the reservoir be capable of delivering the required airflow to the turbine at an inlet pressure of at least 10.8 atm. Approximate descriptions of the complex water balance, temperature distribution and airflow in the formation were developed to complete the design. The final choice of the well spacings and the fraction of the stored air mass involved in the weekly cycle was based on a tradeoff between the investment in air collection manifold and wells. A plan is described for achieving the final equilibrium reservoir by operating at a higher than equilibrium average waterfront pressure of 314 psia for a period of two to five years, followed by reduction to the equilibrium waterfront pressure of 240 psia. A technical description, equipment list and costs for all the plant systems are provided.

In general, the results of the conceptual design of the Brookville Station confirmed the general conclusions of the assessment. While a number of special problems associated with conditions at the site were identified, no limiting technical barrier to the construction of the facility was found. Even though some work has been carried out at the site and the available records of that work were examined, the extent of the knowledge regarding the prevailing underground conditions is not sufficient. Extensive site investigation to study formation depth, pressure, thickness, porosity, permeability, compressibility, caprock integrity and caprock threshold pressure would be needed before a decision could be made to build a plant at the Brookville site. In addition, the study indicated a need for developing more precise models of the airflow and the moisture and heat balance for compressed air storage in porous formations. With respect to the economics of the Brookville Station, a 1981 fuel cost of approximately \$3.00/MBtu corresponds to near equivalency of CAES alternatives with that of installation of a simple cycle turbine plant. This fuel cost corresponds to near the mid-point of several recent estimates of costs of petroleum derived fuels. Since the Brookville Station is a low pressure aquifer storage CAES plant, this general conclusion was anticipated from the assessment results.

CONCEPTUAL DESIGN OF THE SYKESVILLE STATION

A limited conceptual design for a CAES plant employing a conventionally excavated, water leg compensated air reservoir was carried out to test the conclusions of the assessment phase of the study. The generation time, power rating and maximum storage pressure were specified to be the same as those prevailing at the Brookville site, so that the conceptual design of the Brookville surface plant might be used with only minor modification. The geological and economic conditions prevailing near Sykesville, Maryland, approximately 20 miles north of Washington, D.C., were used to carry out the study. A cavern of room and pillar design was prepared and the cost of construction estimated. This resulted in a storage cost of $12.45/kWh for a 600 MW, 10 hour generation time plant, in general agreement with costs for storage used in the assessment. The total plant investment required for the Sykesville Station is approximately $40/kW more than that required for the Brookville Station. For operation in 1983, a simple cycle turbine plant is favored over the Sykesville Station by 30.4 mills/kWh. The 1983 fuel cost corresponding to equivalent generation costs for the CAES and gas turbine plants is $5.49/MBtu, well outside the range of recent estimates of 1983 fuel costs.

AREAS FOR FURTHER INVESTIGATION

The approach taken in defining areas and directions for further work is based on consideration of the following questions:

- What are the significant barriers to the immediate implementation of CAES by utilities?
- What technical effort might, if successful, substantially increase the long-term attractiveness of CAES to utilities?

A number of the potential barriers to the immediate implementation of CAES will be resolved most efficiently by a phased program leading, if successful, to demonstration of each of the three principal methods for carrying out CAES.

To increase the longer range attractiveness of CAES to utilities, programs to reduce capital costs and increase the efficiency of premium fuel usage are needed. New developments in turbomachinery are discussed that could be instrumental in achieving both objectives. Because of the differences in performance characteristics of turbomachinery operating in the conventional gas turbine cycle and in the CAES cycle, developments that improve the efficiency and specific cost of the former do not necessarily benefit the latter. The development of a turbine system with a 40 atm inlet pressure capability is indicated as a desirable goal. An analysis of the relationship of specific output and efficiency to firing temperature indicates that the choice of optimum inital and reheat temperatures in a two-stage expansion train is substantially affected by the introduction of a recuperator in the cycle. Development of a single shaft compressor with suitable flow capacity with a pressure ratio capability of 16:1 to 20:1 is a realistically achievable interim goal. The probability of success in developing a 40:1 pressure ratio compressor with the necessary flow capacity, without intermediate speed changes and inter-cooling, is not considered to be very high.

Because the potential oil savings from widespread implementation of a combined air and thermal storage system are considerable, this system should be given careful consideration. The equipment required to carry out this cycle is so far beyond the present state of technology, that a detailed conceptual design study is required to estimate the capital and operating economics and to identify critical engineering problems and the necessary development programs.

A area requiring experimental investigation is that of the possible effects on the turbine caused by materials carried out of the underground reservoir. Sulfur compounds, invariably contained in the fuel, and alkali metals (particularly sodium), lead, or vanadium interact in a complex way in a combustion turbine to produce very rapid attack on metal parts in the hot gas path leading to a serious shortening of the turbine blade life. This phenomenon is known as hot corrosion. Because of the presence in the fuel of alkali metals and sulfur compounds, it is customary to cite a safe limit for a total of alkali metals, lead and vanadium in the inlet air of the order of 5 ppb. Use of special alloys or ceramics and lower firing temperatures increase the tolerance of the turbine to fuel contaminants. A second potential problem related to the carryover material from the cavern, is that of particulate erosion. Most experience in the gas turbine industry derives from the effect of particulates on the erosion of compressor blades. If the total particulates in the air entering the compressor are less than 0.45 mg/m^3, and if the fractions of particles smaller than 10 microns is less than about 5 weight percent, then compressor erosion is minimal. The air inlet to the turbine from the underground air store must meet conditions of particle content and corrosive element content comparable to these, so as to provide the necessary life and reliability to the compressed air energy storage installation. Failure to do so would result in unacceptable forced outage rates and operating and maintenance costs. An experimental program is needed to measure particle size distribution and air chemical composition at each site to provide the information needed to design an appropriate air cleaning system.

The potential mechanical and chemical changes induced in host formations by the temperature, pressure and humidity cycling associated with CAES needs further clarification. The questions involved differ for each type of storage reservoir. It is not clear yet to what extent one may generalize, particularly with regard to mechanical behavior based on work at one site or in one formation. Because of the plastic flow behavior of salt at relatively low temperatures and pressures, theoretical and experimental work is indicated to guide field studies leading to a CAES plant employing a solution mined cavern.

The mathematical description of air and water flow in porous media that was used in designing the Brookville Station does not appear adequate for a detailed design study. For example, work already in progress elsewhere, indicates that the steady state approximation on which the conceptual design calculations were based introduces an appreciable error into the calculated formation pressure losses. The existence of temperature and moisture gradients around each well bore was not taken into account and will surely modify the behavior of the reservoir compared to that calculated using the simple flow model. A more detailed treatment to describe the performance of aquifers should be carried out.

Because depleted oil and gas reservoirs represent potentially available and well characterized formations for carrying out compressed air storage. A detailed examination of a depleted reservoir to evaluate the interaction between stored compressed air and residual hydrocarbons is indicated. The experience of the petroleum industry in fire flooding should be examined. Some preliminary laboratory investigation is required of the interaction of bitumen impregnated reservoir rock with hot compressed air to observe either ignition or oxygen depletion.

As has already been noted frequently in this summary, the nature of the specific site selected for CAES and the system needs of the utility with access to the site will be the determining factors in the technical and economic feasibility of any CAES project. This was most clearly shown in carrying out the conceptual design of the Brookville and, to a lesser extent, Sykesville Stations. It is clear that the most important area for further work is that of carrying out preliminary designs of CAES plants for specific sites which, coupled with appropriate experimental programs at the sites, could, if successful, lead to pilot and demonstration CAES programs.

Section 2

REVIEW OF PREVIOUS WORK

2.1 INTRODUCTION

Compressed air storage on a small scale in rock caverns was used by the mining industry for many decades as a means of powering pneumatic equipment. Patents have been issued dating back to the turn of the century. The first references to compressed air storage for utility application were included in patents issued to Gay in the United States (1948), the turbine manufacturer Stal Laval in Sweden and Great Britain (1952), and to Djordjevic in Yugoslavia (1950). A technical article describing the potential application to United States utilities of compressed air storage coupled with gas turbines was published in 1951 (Ref. 8). Since then a number of papers and patents have appeared as the idea has undergone conceptual evolution.

Frequently, the articles have presented the viewpoint of advocates, citing the many apparent advantages to utilities of employing compressed air storage (Refs. 12, 16, 18, 28, 34, 50, and 52). Many of these publications resulted from the work of the major manufacturers of industrial gas turbines, both in the United States and in Europe. Recent appraisals generally favorable to the application of compressed air storage have been published by those associated with the United States electric utility industry (Refs. 23, 45, and 46) and by firms dealing with underground construction (Refs. 61, 62, and 63). Announcements of preliminary plans, or references to well advanced plans, for constructing compressed air storage plants (Refs. 5, 7, 11, 17, 44, 50, and 58) have appeared on several occasions, but until 1974 no commitment had been made by a utility to construct such a plant. The first compressed air storage plant is now being constructed by the German utility Nordwestdeutsche Kraftwerke A.G. with plans for operation in 1977 (Refs. 3, 6, 9, 11, 39, and 54).

In view of the relatively long history of this technology as a concept and its apparent attractiveness for utility application, it is puzzling that there have been no commitments to build plants in the United States. It is the purpose of this section of the report to provide a brief overview of the types of compressed air plants that have been considered, to review the historical development of the concept, and to present a summary of the characteristics of the surface and underground components of the alternatives as well as the operating characteristics for those systems described in the literature. The objective of this review, in addition to providing background for readers of subsequent sections of the report, is to formulate from the literature hypotheses as to the barriers that have delayed implementation of compressed air storage. These hypotheses are then tested against the findings of the present study to determine which, if any, are relevant to the current situation prevailing in the United States.

As part of a general assessment of energy technologies being conducted for the Energy Research and Development Administration and the Electric Power Research Institute, a comprehensive review of the literature of compressed air storage has been written from a somewhat different viewpoint than that of the present review. That report, which became available in a draft form during the course of this assessment study, should be consulted for additional details.

2.2 GENERAL CHARACTERISTICS OF COMPRESSED AIR ENERGY STORAGE SYSTEMS

A compressed air energy storage (CAES) plant can be considered to consist of the systems shown in Figure 1-1. In operation in a utility network during periods of low demand such as nights and weekends, the power generated by efficient, low-fuel-cost plants (either nuclear or coal fueled) would be taken from the utility grid, through a switchyard and transformer, to power a large electric machine driving a compressor train. The air from the compressor train, after cooling and perhaps dehumidification, would be injected into some form of underground storage chamber. Under the control of the utility dispatcher, the compression phase would be terminated when the incremental energy costs to the utility exceeded some target, and the underground storage would be valved off. The electric machine would be disengaged from the compressor train. When the utility system incremental energy cost exceeded some preset value, or when an emergency situation arose, the dispatcher would engage the electric machine with the turbine expander train and open the valve connecting the underground storage to the expander train.

If it had been necessary to cool the air before storage, then it would be necessary to heat it as it was released from storage. This can be done in a variety of ways, but for the near term, use of fuel in a combustion turbine is most practical; the heated air is then allowed to expand through the turbine providing shaft power to the electric machine now operating as a generator. Electric power from the generator is fed to a step-up transformer and through a switchyard to the utility grid. Generation can continue until the air in the cavern is exhausted. If power is still required by the demand on the utility grid an appropriately designed plant can continue to operate as a conventional turbine plant, but the rating will be only one-third to one-half that of its rating as a compressed air plant because the turbine must power its compressor when no stored air is available. When generation is no longer required, the dispatcher can seal off the air store and disengage the turbine from the electric machine in preparation for the next compression phase.

Because the gas turbine in the CAES cycle does not have to power a compressor, the heat rate, which provides a measure of the amount of fuel required to produce a unit of electricity (Btu/kWh), is substantially less than in conventional gas turbines. Thus the requirement by the utility for oil or natural gas to meet peak demand can be reduced to 35 to 50 percent of that which would be required if the peak load were met by conventional gas turbines.

The saving in fuel costs that results is partially offset by the costs of fuel needed to power the base load plant that provides power during the compression phase. Thus, the two critical operating parameters of a compressed air plant are its heat rate (Btu/kWh) and its compression energy factor, which is defined in this report as the ratio of net electrical energy generated divided by the electrical energy consumed to compress the stored air. The relative cost of turbine fuels and of offpeak energy available for pumping will be important characteristics of a utility in determining whether compressed air storage is economically advantageous.

A third important characteristic of a compressed air plant is the capital investment required to build it. The overall measure of the economic benefit of a compressed air plant is the cost of generation of electricity by the plant. This is the sum of the capital charges, fuel and pumping power charges, and operating and maintenance charges of the plant. If the generation costs for a compressed air plant are not lower than those of alternatives available to the utility, then it is improbable that the utility company will commit itself to build the plant in the absence of some overriding institutional consideration. Even if the sent-out costs are potentially favorable, there may be a number of other reasons for a utility not to commit to construct a plant. Possible factors in that decision will be considered later in this report.

There are a number of alternatives for carrying out the operations needed in a compressed air storage plant. For example, instead of heating the air from storage with fuel, one can either store it at the compressor discharge temperature, which may create geomechanical problems, or one can reheat cooled air, using the stored heat generated during compression (Ref. 29). To implement this approach requires development of an appropriate, low-cost heat storage system as well as some advances in turbomachinery design and construction. Aspects of this approach will be discussed in subsequent sections of this report.

Another possible method for freeing the system from the constraint of the use of petroleum-derived fuels is to use coal or a coal-derived fuel (Refs. 4 and 33). Since this approach may add substantially to the capital investment required, it would be more suited to midrange than peaking applications. The technology for employing coal-derived fuels in gas turbines is being developed for combined cycle applications; it should also be considered for compressed air storage when it is sufficiently advanced.

Underground space, either in caverns or in the pore space in porous rock formations, may be employed for storage of compressed air. The caverns may be natural or mined. In the latter case, they may be constructed by conventional methods, by nuclear explosives, or by the solution mining of salt. The characteristics of caverns prepared by these techniques are compared in subsection 2-5. Since porous rock formations generally contain either fresh water or brine, they are called aquifers. To prepare an aquifer for compressed air storage, the water initially present must be displaced by air.

The efficiency of gas turbines falls off very rapidly when the inlet pressure is more than 5 to 10 percent away from the design pressure. Thus it is necessary that the pressure at the turbine inlet be nearly constant during the generation period. This can be accomplished either by using a constant volume-variable pressure reservoir with a throttle to control the pressure at the exit to the reservoir, or by the use of a variable volume-constant pressure reservoir. Some distinguishing characteristics of these two modes of storage are:

Constant Volume Storage

- The formation used for storage is subjected to substantial pressure variation during cycling ($\Delta P > 10$ atm).
- The minimum pressure in an air reservoir must exceed the turbine inlet pressure.
- The compression energy needed to raise the pressure in a cavern above the turbine inlet pressure is not recovered during expansion.
- Mined caverns or aquifers of low permeability may be applied to carry out this mode of storage.

Constant Pressure Storage

- The formation used for storage is subjected to very little pressure variation ($\Delta P < 1$ atm).
- Mined caverns may be used if a hydrostatic leg is provided to permit water to flow to and from a surface reservoir during charge or discharge. The pressure in the air reservoir is determined by the height of this water column.
- Aquifers of very high permeability may also behave as constant pressure reservoirs.
- This mode makes the most efficient use of underground storage space and compression energy.

2.3 HISTORICAL SUMMARY

As noted previously, plans for compressed air energy storage plants have been discussed frequently in the literature, but with only one exception these plans have not materialized. In this subsection, a summary of these developments will be presented.

Much of the interest, particularly in Sweden, was due to the activity of the gas turbine manufacturer Stal Laval (Ref. 36). A reason for particular interest in Sweden in storage using a water leg compensated, excavated cavern, was the rapid development of hard rock mining technology in that country as a matter of national priority (Refs. 13 and 58). In a series of papers presented between 1970 and 1973, a conceptual design for a compensated plant was described in some detail (Refs. 34, 35, 36, 57, 58, 59, and 60). In 1972, plans were announced for the "world's first pumped air storage plant," to be built by Sydsvenska Kraft A.B. near Växjo, in southern Sweden (Ref. 5). This was planned to generate for six hours at a constant pressure of 25 atmospheres and to be screened by a water curtain over the cavern, to limit leaks. The same report mentioned plans by the Swedish State Power Board to build a similar plant. These plans were further elaborated in 1973, when it was reported that the Swedish State Power Board had conducted successful test borings at a site north of Norrköping and was likely to soon place an order for a 230 MW prototype plant for that site (Ref. 44).

Apparently the two Swedish utilities were cooperating in the planning for this development and had selected compressed air storage over underground hydroelectric because of the smaller storage volume required in the former (Ref. 57).

Unfortunately, these plans have been delayed or cancelled. Two reasons have been cited. The November 1973 oil embargo has been offered as one explanation (Ref. 33); the Swedish utilities were not willing to build a peaking plant that required oil derived fuels, considering the potential for supply interruption. A second reason has been suggested: that insufficient offpeak power from nuclear plants was yet available in Sweden to permit the economical operation of a compressed air plant (Ref. 6). In no case has there been any indication that technical problems caused the delay.

In the Federal Republic of Germany, the development of compressed air storage does not appear to have been actively carried out over as long a period as in Sweden. Studies on the technical and economic feasibility of compressed air storage carried out in the late 1950's by the Geological Survey concluded that it was feasible for utilities and that abandoned salt mines provided the cheapest means to carry out the storage (Ref. 53). There was no apparent followup to this assessment. A combination of circumstances has now resulted, however, in the construction of the first plant in Germany. The critical difference from the situation in Sweden is apparently that a utility Nordwestdeutsche Kraftwerke A. G. (NWK), with both a potential excess nuclear capacity and an assured supply of natural gas has identified an opportunity for improving its performance by incorporating compressed air storage.

Because of the high proportion of nuclear generating plants forecast for the mid-1980's, some form of energy storage in addition to the use of storage heaters was indicated in the planning of NWK. There are no suitable sites for pumped hydroelectric storage in the NWK service area, and the geology does not appear to lend itself to underground pumped hydroelectric storage. As a result of previous oil exploration activity, it was known that salt formations suitable for high-pressure storage existed in the area. Another consideration in selecting a site was that the brine generated by the solution mining be disposable by release into a local estuary. The quantities of salt involved are too small to be economically valuable to a chemical company.

A site for a CAES plant was selected between Bremen and Oldenburg on the Hunte River, very near the Weser estuary. The plant is designed to generate 290 MW for two hours and to compress air for eight hours daily. There will be two solution mined salt caverns with a total volume of 270,000 to 290,000 m^3 at a depth of 600 to 800 meters. Two caverns will be used, so that the generation can be maintained in the event of the loss of pressure from one cavern; the compressors are sized too small to operate the high- and low-pressure turbines by themselves. The caverns will be pressurized to about 65 atmospheres maximum, and the pressure will be allowed to fall to 45 atmospheres during discharge. This pressure range was chosen as an optimum in the tradeoff between cavern cost and equipment cost. A constant volume system was selected because there are no formations at a depth of 450 to 460 meters in the North German coastal area that are suitable for caverns for constant pressure systems.

Drilling of the entrance shaft began in March 1975 and washing of the cavern in July. Two years will be required for completion, and the costs are estimated as follows (1973 basis):

Equipment	68	million DM (~$29.6 million)
Cavern	18.5	million DM (~$8.0 million)
Engineering and Other	5.5	million DM (~$2.4 million)
TOTAL	92.0	million DM (~$40 million)

This amounts to approximately $138/kW. It is estimated that doubling the cavern size to accommodate four hour generation would raise the total cost of the facility to 106 million DM ($168/kW), of which the cavern cost would be about 30 percent (Refs. 39, 40, and 41).

This plant has been widely described in the literature (Refs. 3, 6, 9, 11, 39, 40, and 41). A new turbine system under development for this facility comprises a high-pressure combustor and turbine (40 atmospheres inlet pressure) and 4.5 expansion ratio, and a low-pressure combustor (10 atmospheres inlet pressure) and 10:1 expansion ratio (Refs. 52, 54, and 66). This equipment will be described in more detail in a later section of this report.

An air storage plant of quite different design is being considered by the utility Rhenische Westfalische Elektrizitätswerke (RWE), which has its headquarters in Essen (Refs. 37, 38, and 51). The design is that of a water leg compensated cavern, with excavation to be done by boring rather than con ventional blasting. The site is to be near the very large pumped hydroelectri plant near Vianden, on the Luxembourg-German border. A plant with a four hour generation time, 300 MW rating, and a turbine inlet pressure of less than 45 atmospheres has been described. The decision to commit or not to the building of this plant will probably be made in 1976.

The introduction of compressed air storage into the electricity grid in England and Wales has been considered on several occasions, but the conclusions have thus far been negative. For example, a study carried out by the Central Electricity Generating Board (CEGB) in 1960 concluded that the costs of sealing the cavern and employing a water leg made compressed air storage economically unattractive. Attention then turned to unlined, uncompensated hard rock caverns, and some preliminary pressurization tests were carried out on an unlined test gallery at the Ffestiniog pumped hydroelectric site in North Wales. However, a site assessment showed that the only suitable crystalline rocks were in the western part of the island, where pumped hydroelectric sites were available, and the decision between an established technology and a new one favored pumped hydroelectric (Refs. 14 and 22). Morc recently, CEGB has reexamined those conclusions and generally confirmed them.

The earliest date of significant commercial application of compressed air storage in Great Britain is estimated to be 1990 (Ref. 27). The 7.7 GWh pumped hydroelectric plant at Dinorwic is likely to meet the CEGB system needs for some time. A study of the system performance of a plant of the NWK design was carried out and it was found to be uneconomical in England now. Because the coal/oil price differential is not great enough in England, the introduction of compressed air storage only appears attractive when the nuclear capacity significantly exceeds the winter base load. The Northern Ireland Electricity Authority, however, is reported to be considering a plant of the NWK design (Ref. 30). The combination of compressed air and heat storage to provide "true energy storage" is currently receiving attention in laboratory investigations at the CEGB Marchwood Engineering Laboratories (Refs. 24 and 29). This approach is discussed in more detail elsewhere in this report.

No utility company in the United States has yet announced plans to construct a compressed air storage plant. However, there is substantial interest among many utilities today, and the current situation is reviewed in Section 6 of this report. As noted earlier, papers on compressed air storage have been published since 1951 (Ref. 8). Three U.S. manufacturers of gas turbines have published technical articles on aspects of compressed air storage (Refs. 12, 16, and 28), and a number of U.S. patents have been issued. One company has been formed to commercialize the use of compressed air storage in aquifers (Ref. 50). Studies of the feasibility of compressed air storage in caverns excavated by nuclear explosives (Ref. 26) and general assessments of compressed air storage (Ref. 49) have been completed for the Atomic Energy Commission. Work was carried out on the equipment needed to store compressed air in a cavity in a salt dome, extracting geothermal heat from the salt during the expansion phase without the use of fuel (Ref. 67). This investigation has been terminated (Ref. 68).

Results of the recent general assessment of energy storage technology for the Energy Research and Development Administration, as well as papers by people connected with the utilities (Refs. 23, 45, and 46) and with underground construction, have indicated that the current conditions in the United States are more favorable for utility application of compressed air storage (Refs. 61, 62, and 63).

Elsewhere in the world, there have been sporadic reports of interest in aspects of compressed air storage for utilities. Studies commissioned by Electricité de France and carried out by Societé Générale d'Etude et d'Equipment examined the feasibility of storage in aquifers in the Pays de Bray and in caverns of the salt beds in southwestern France (Ref. 7). These studies have been discontinued without leading to a commitment to build a plant (Ref. 49). The rapid introduction of nuclear generation planned for the Electricité de France system and the successful hydrocarbon storage program in thick salt beds near Marseille (Ref. 20) are two factors that may lead to renewed interest in compressed air storage in France.

There is a reported interest in compressed air storage in salt in Denmark, which has formations similar to but not identical with those employed by NWK (Ref. 7). A proposal has been reported to employ compressed air storage coupled with tidal power in salt domes at the Bay of Fundy in Canada (Ref. 2). There have been references to interest in compressed air storage in Finland (Ref. 28), South Africa (Ref. 44), and Yugoslavia (Ref. 50), and a patent concerning compressed air storage has been issued in Poland. However, in none of these countries has the decision to build a plant been announced.

2.4 CHARACTERISTICS OF THE SURFACE PLANT

The principal components of the surface plant of a compressed air storage facility are the motor/generator, the compressor train, the expander train, the switchyard and transformer, the control systems, and the auxiliaries. Only two designs, those of the Swedish utilities plan and the NWK plant, have been described to the extent of referring to most of these components. The transformer, switchyard, and auxiliaries have generally been ignored, since operation in a compressed air storage plant imposes no special requirements on them.

TURBINE-EXPANDER TRAIN

Performance parameters for five expander trains employing characteristics of industrial combustion gas turbines are summarized in Table 2-1. References 12 and 16 are based on existing gas turbine designs and Reference 28 on a design of a United States turbine manufacturer. References 35 and 57 discuss two generations of designs for the Swedish plant and Reference 54 the NWK plant design. The lower heat rates (Refs. 16 and 28) reflect the incorpo tion of a recuperator in the cycles. The lowest heat rate corresponds to a cycle employing two stages of expansion with reheat (Ref. 28), similar in concept

Table 2-1

CHARACTERISTICS OF COMBUSTION TURBINES
FOR COMPRESSED AIR STORAGE

Reference	Pressure Ratio	Inlet Temperature (°F)	Specific Turbine Flow (lb air/kWh)	Speed (rpm)	Output (MW)	Heat Rate Btu/kWh
12	10:1	1850	14	3600	168	6200
16	11:1	-	-	3600	169	4600
28	40:1	2000	11	3600	-	4000
35	43:1	1470	13	3000	220	4770
57	25:1	1650	13	3000	232	5370
54 High pressure	4.5:1	1022	11.4	3000	290	5560
Low pressure	10:1	1517				

to the NWK design (Ref. 54); the difference in heat rate is attributable to the presence of a recuperator and the higher firing temperature in the former case. One effect to be expected from the difference in firing temperatures for these various designs, if the degree of metal cooling is comparable, is that the machines with a lower firing temperature will be less susceptible to hot corrosion caused by sulfur and alkali metal compounds.

The turbine design for the Swedish plant was based on a commercial machine with three shafts running at different speeds and a single stage of expansion with a single-flow high pressure unit and a double-flow low pressure unit (Ref. 50). As indicated in Table 2-1, the initial design called for a 43:1 expansion, but this was subsequently modified to 25:1 (Ref. 54). For the air storage application, the design of the commercial machine was modified so that the components operate in common off a single shaft at the speed (3000 rpm) determined by the network frequency (Ref. 57).

For the NWK plant, two stages of expansion with intermediate reheat will be employed. The low-pressure turbine is of conventional design, although some modification of its combustor would be required for employing vitiated air from the first stage. The high-pressure turbine will be a new design, which operates at temperatures and pressures within the range of current steam turbine technology. These two units are mounted on a single shaft (Ref. 54). An alternative that has been considered for this plant is the use of a high-pressure recuperator in place of the high-pressure combustor. On the basis of work reported by Hartmann and Hoffmann of RWE (Ref. 38), it was concluded that this approach would increase the capital cost by 17 percent while lowering the heat rate to 4100 Btu/kWh (Ref. 52).

For the cycle coupling storage of the reject heat from the compressors with compressed air storage, a somewhat different turbine expander would be required than any of those considered above (Ref. 29). A variable pressure ratio, from 100:1 to 60:1 with an inlet temperature around 1560 F, has been suggested as one set of design parameters, corresponding to a specific turbine flow of 8.2 lb/kWh. Such a machine has not yet been designed.

COMPRESSOR TRAIN

Less detail has been reported concerning the design of the compressor train for a compressed air storage plant than for the expander train. The NWK plant will employ two compressors: an axial flow, 3000 rpm unit of industrial design, and a six-stage, 7600 rpm, centrifugal unit to boost the output of the axial unit to a final pressure of 68 atmospheres. The mass flow through the train will be 238 lb/s, about one-quarter that needed to power the expander train. The compressor/expander trains in this facility thus will not be operable as a unit. Intercooling and aftercooling will be accomplished with closed-loop heat exchangers flowing 16,800 gpm during the charging of the cavern (Ref. 52).

The compressor train for the Swedish plant, when it was designed for a 43:1 pressure ratio, employed three stages of compression with intercooling and aftercooling. The low-pressure and intermediate-pressure compressors were to run directly from the motor shaft; the high-pressure compressor would be geared to the shaft. The low- and intermediate-pressure compressors were of the type used with the gas turbine set, modified to operate at 3000 rather than 3600 rpm. Thus, the airflows of the compressor train and expander train were matched, and the unit was capable of operating without drawing air from storage (Refs. 34 and 60). The modification design operating at a 25:1 pressure ratio employed only two stages of compression (Ref. 57).

The compressor required for the combined heat/air storage cycle would be of a new design. To save as much of the heat as possible, it is proposed that the intercooling not be employed. Compression would be in two stages, with a discharge temperature of 1650 F at a pressure of 100 atmospheres (Ref. 30).

MOTOR/GENERATOR

In general, no unusual design features have been considered to be required in the motor/generator unit. For the NWK plants, a three-phase, 341 MVA, two-pole, hydrogen cooled unit providing 21 kV at 50 hertz is planned. The design efficiency of this machine is 0.85. Static excitation from the compressor side with aircooling of SCR's will be employed. Excitation from the compressor side limits the shaft output to the compressor to 200 MW (Refs. 40, 52, and 54).

The NWK plant will employ self-switching synchronized (SSS) couplings between the motor/generator and the turbines. These couplings which can be engaged and disengaged while the machines are in motion, allow the turbine to be used to start the compressor and then be disengaged to prevent losses due to "windmilling" of the turbine. The connection between the compressor and the turbine will be by a coupling that can be disengaged only when the machines are stationary. Both couplings will be controlled remotely by a dispatcher (Ref. 40). A similar arrangement was planned for the Swedish plant (Ref. 57).

CONTROLS

Special controls over and above customary gas turbine electric and mechanical controls have not been considered in detail in most papers on compressed air storage. Valving to control and throttle remotely controllable air from the cavern will be needed both for uncompensated storage and to achieve good part-load efficiency for any CAES system. The fact that with the compressor separated from the turbine the CAES system is capable of much higher efficiencies at part load than is a conventional gas turbine has been cited as one of the advantages of the CAES system (Refs. 39 and 40). It has been shown that the heat rate may not vary by more than 10 percent from full load down to 30 percent load when the airflow is throttled to reduce output (Ref. 38). Controls to regulate changeover from one mode to another and to protect the compressor against surging have been described (Ref. 16). The development of these controls may be a significant task in the final implementation of compressed air storage (Ref. 33).

2.5 UNDERGROUND INSTALLATION

The characteristics of some storage volumes that have been proposed for air storage schemes are summarized in Table 2-2. It is particularly difficult to relate to one another the cost per kWh or cost per unit volume of storage reported in different papers. The factors affecting conventional mining costs can be summarized as follows:

- Rock type and hardness
- Depth and size of excavation
- Shaft requirements
- Stability requirement
- Special sealing requirements
- Mining method employed
- Equipment cost
- Prevailing labor rates
- Land acquisition costs

Table 2-2

CHARACTERISTICS OF SOME PROPOSED COMPRESSED AIR STORAGE CAVERNS

Type	Constant	Pressure (atm)	Depth (m)	Temperature (°C)	Spec Volume (m^3/kWh)	Costs		Reference
						\$/kWh	\$/m^3	
Salt	V (Th)[a]	45 to 66.5	600	20	0.517	12.50	24.17	51
Salt	V (Th)	45 to 66.5[b]	600 to 800	20 to 50	0.517	13.80	26.67	40,42
Aquifer	P (Aq)	15.3	158	82	2.22[c]	1.17	0.53	12
Nuclear	P (±5%)	10	464	49	7.03	5.46	0.78	26
Hard rock	P (H)	43.5	435	15	0.124	2.20	17.74	58
Hard rock	P (H)	28.2	293	52	0.223	2.78[d]	12.47	60
Slate	P (H)	47	459	27	0.114	--	--	38,50
Hard rock	P (H)	44	--	182	0.272	0.74	2.72	16
Hard rock	P (H)	16.3	550	52	0.382	--	--	62
Hard rock	P (H)	28.2	960	52	0.222	--	--	62
Hard rock	P (H)	60	--	66	0.115	0.68	5.90	45

(a) Th = Throttled, Aq = Aquifer, H = Hydraulic leg.
(b) Includes 5 atmospheres in cavern from weight of air column.
(c) Fivefold excess storage volume.
(d) Includes both upper and lower reservoirs.

Because of the specific character of many of these factors, it is difficult to provide a usefully narrow range of excavation costs for making an economic assessment of compressed air energy storage. For example, the range of costs for conventional underground construction in the United States has been estimated to be from \$2.50 to 60.00/m^3 (Ref. 26), while for tunneling under favorable conditions in the United States the cost has been estimated to be about \$35/m^3 (Ref. 49). The estimated cost for excavation reported in the literature usually does not include the cost of site exploration and development. In some cases, the interest on capital tied up during construction is included as a cost incurred in construction; in other instances it is not.

In a particular case, it is frequently unclear whether the disposal of the brine or rock tailings resulting from the cavern excavation has been credited or debited to the cost of constructing the cavern. A further complication arises from the usual practice of including in the overall cavern costs for a hydraulically compensated system a cost of the dam and other surface facilities needed to impound and control the water. These factors contribute to the great range of costs in \$/m^3 for cavern excavation recorded in Table 2-2.

CAVERN EXCAVATION AND ECONOMICS

With the exception of the caverns for the NWK storage facility, the characteristics needed for a salt cavern for compressed air storage have received little attention in the literature. However, caverns currently in operation in the United States for hydrocarbon storage appear to have approximately the required characteristics (Ref. 1). For example, the southeastern Michigan gas storage facility employs two salt caverns with a total volume of 318, 000 m^3. These caverns cycle during a prolonged season between a maximum pressure of 238 atmospheres and a minimum pressure of 75 atmospheres, and at the minimum pressure they are capable of delivering gas at a rate corresponding to the air required for a 240 MW output from a gas turbine.

The NWK facility (Refs. 40, 42, and 51) will employ two salt caverns with a total volume of approximately 280, 000 m^3, the top of the caverns lying at a depth of 600 meters and the bottoms at a depth of 800 meters. Between the top of each cavern and the top of the salt belt, there will be a salt ceiling with a thickness of 100 meters. Each cavern will be very closely cylindrical, 30 meters in diameter. Apparently a great deal of attention is being paid in the excavation of these caverns to obtaining an ideal cylindrical shape. Others (Ref. 60) have claimed that the configuration of the cavern for constant volume storage is not as important a factor as it is in the case of the constant pressure system.

It has been asserted (Ref. 59) that caverns excavated by subsurface detonation of small nuclear weapons are approximately spherical in shape and have volumes that are pretty largely independent of cost. Neither of these assertions appears to be true on closer examination (Ref. 26). Such caverns seem to have the characteristic shape of rubble-filled chimneys roughly cylindrical in shape. Because of the rubble filling, their characteristics in regard to pressure drop may be intermediate between those of an excavated cavern and those of an aquifer. While the cost of nuclear weapons may be only roughly proportional to the size of the weapon, the safe depth at which they may be detonated increases with increasing weapon yield; the larger the cavern excavated in this fashion, the greater the depth of shaft that must be drilled, thus adding to the cost of the storage volume.

Considerable attention has been paid in the literature to caverns excavated for use with hydraulic compensation and constant pressure air storage schemes. An early proposal (Ref. 8) was to construct a compensated system with pyramid shaped caverns. The advantages of this design have apparently not been further discussed, but a similar design has been proposed in the patent literature. A proposal that appears to have received considerable acceptance (Refs. 58 and 60) is to construct the air storage volume as a number of parallel tunnels blasted side by side in a suitable rock formation. It is anticipated that with the excavation carried out in this fashion the cracking of the rock induced by the blasting will result in minimal leakage of air from the storage volume (Ref. 13).

A quite different design was recently proposed for a facility planned by RWE. Lenssen presents a very careful discussion of the factors entering into this design (Ref. 38). A single continuous tunnel in the form of an elongated loop, with long sides of about 2100 meters and a radius at the semi-circular ends of 125 meters, will be constructed with a tunnel boring machine. An entrance shaft 6 meters in diameter, sufficiently large to admit the boring machine, will be constructed and the machine needs to be lowered only once through the shaft to begin its excavation. The tunnel diameter will be 5.5 meters and the total length of the tunnel 5000 meters. Not only does this design eliminate the multiple lowering of the boring machine, but it also allows maximum advantage to be taken of the good rock structure. To reduce contact between air and water in the storage volume, the loop may be tipped slightly from the horizontal, at an angle of about 2.5 percent. However, such an inclination of the loop will result in a 2.5 atmosphere pressure variation during operation of the storage chamber.

The air and water shaft must be dimensioned so as to result in acceptable pressure losses. It will probably be necessary to line the shaft with steel to limit friction losses (Ref. 60). Air collection shafts of 0.6 to 0.7 meter (Refs. 26 and 58) and air manifolds of 0.91 meter diameter (Ref. 11) have been proposed. The usual water shaft diameter proposed is 6 meters (Ref. 38). However, one way to control the so-called champagne effect is to enlarge the diameter of the water shaft to 12 meters (Ref. 59).

The siting and construction of the cavern will be a crucial operation in the success of any air storage scheme. From the papers of Herbst (Ref. 42) and Lenssen (Ref. 38) it is apparent that the decision between constant volume and constant pressure storage depends critically on the geology of the available, suitable site. Lenssen further stresses the site specificity of the particular design employed. A number of possible problems associated with the cavern must be considered during its siting: contamination of the surrounding aquifer; damage to urban structures and services as well as to potable water supplies, caused by the lowering of aquifers or their contamination; and provision of a means for periodic inspection and leak testing (Ref. 48). Furthermore, cavern construction must be done in a way that will minimize damage to the rock, to reduce the leakage from the storage volume when it is in operation.

It has been pointed out that the field studies must "be done with great precision" (Ref. 13). These studies must map fissures in the rock, providing their direction, width, and frequency; determine the presence on intersecting fracture zones and faults; determine the permeability of the formations by water pressure tests; and determine the characteristics of the overburden, which will decide what surface effects may be observed at the site.

SUITABILITY OF ROCK FORMATIONS

As noted in the previous subsection, the presence of a suitable rock formation at the appropriate depth may largely determine what technical option will be employed to carry out compressed air storage. The suitability of the rock for excavation and employment with hydraulic compensation generally depends on its being unaffected by contact with water and possessing appropriate bedding planes, low permeability, and relative integrity with regard to vertical or horizontal cracking. Lenssen (Ref. 38) has selected a firm laminated rock: e.g., shale, slate, or schist, for the RWE facility. It is further desirable that the rock quality be such that it can be used for concrete aggregate or as crushed stone for highways (Ref. 60). For example, a detailed feasibility study of a compressed air storage scheme was conducted at a site from which gneiss, which is excellent as a concrete aggregate would be excavated (Ref. 62).

Harboe (Ref. 33) asserts that good rock for hydrostatically compensated excavated rock caverns is available in Sweden and along the east coast of the United States, from Washington D. C. northward. A study conducted by the University of Massachusetts has identified 90 formations in New England that appear to be potentially suitable for either compressed air storage or underground pumped hydroelectric storage (Ref. 69). On the other hand, in a study of rock in England, undisturbed hard rock sites were identified only in the western part of the country. The chalk formation prevailing in the heavily populated southern and eastern parts of the island are not suitable for air storage unless the caverns constructed in them are lined with steel, greatly adding to the expense (Ref. 14).

For nuclear explosions to be most effective, the rock in which they are carried out must contain an optimum amount of water and not be too impermeable or lacking in porosity. A number of investigations have been carried out to identify appropriate rock, in connection with studies by the Atomic Energy Commission (Ref. 26).

Considerable attention has been given to the suitability of salt for the excavation of tight storage caverns. In planning the NWK facility, petromechanical investigations showed that a fine-grained salt deposit containing 5 to 10 percent insoluble material (clay, anhydrite, or sand) was most suitable for pressurized storage. The first test drilling at the selected site resulted in the identification of a formation containing large crystals free of insoluble materials and including stringers of potassium-rich salt, the presence of which would lead to an irregularly shaped cavern. Analysis of the cores by geologists led to the recommendation that a new test hole be drilled 150 meters from the initial site. This resulted in the identification of excellent salt deposits for pressurized storage (Ref. 42). Because the salt dome must be isolated from ground water (it would otherwise have dissolved before this), such formations have been generally assumed to provide minimum leakage or possible contamination of ground water. Frequently, disposal of the brine by injection into saline aquifers is practiced (Ref. 46).

CHARACTERISTICS OF AQUIFERS OR DEPLETED RESERVOIRS

Much of the information with regard to storage in these structures comes from the experience of natural gas storage, which has been carried out in depleted gas fields since 1915 and in aquifers since 1931. The characteristics of these gas storage fields vary widely: in depth, from 90 to 2700 meters; in pressure, from 6.4 to 312 atmospheres; and in area, from 220,000 m^2 to 160 million m^2 (Ref. 31). Some gas storage fields now in operation employing aquifers or depleted oil and/or gas reservoirs have the characteristics that might allow them to serve as CAES storage reservoirs if the turbomachinery to match their operating pressures were available (Ref. 31).

The general structural requirements for an air storage formation and for a gas storage formation are similar: dome, reef, or anticline traps to prohibit lateral air bubble migration; an impermeable cap rock covering a porous storage volume, and a porous stratum of sufficient volume and permeability (Ref. 12). A study using typical aquifer characteristics indicated that for all depths from 120 to 1200 meters air storage could be carried out in an economically favorable fashion, but that below 600 meters very impermeable formations are unfavorable. A typical aquifer storage facility in this study consisted of 50 wells, each 30.4 cm in diameter and filled to a depth of 158 meters in a formation of porosity 12 percent and permeability 1.13 darcy, with a ground water pressure of 15.3 atmospheres, and employing an aquifer air bubble five times the daily air demand. To decide whether a particular aquifer would fit the necessary economic criteria, it is necessary to have porosity and permeability data on the aquifer, and in accordance with the conclusions of this study (Ref. 12) in general the compressors for the storage facility must be matched in their output pressure to the formation pressure in the aquifer.

RESERVOIR TEMPERATURE

In Table 2-2 it can be seen that the assumed maximum operating temperature for various proposed compressed air schemes cover a wide range: from 15 to 182 C. In fact, the temperature range of operation of presumably the identical salt cavern has been estimated to be 20 to 50 C (Ref. 35) and 10 to 40 C (Ref. 52). In the latter case, it was asserted that the maximum air inlet temperature was limited to 80 C because of the use of concrete to encase the steel inlet/outlet tube. The maximum temperature of 40 to 50 C was presumably based on the mechanical properties of the salt, but in neither article was a basis for arriving at this temperature explained.

In the case of a nuclear excavated cavern (Ref. 26), not only was a maximum temperature of 49°C proposed but also an example in which the maximum temperature was allowed to reach 350 C was considered. In the reference it was concluded that operating at the higher storage temperature produced an economic disadvantage because of the larger storage volume required at that temperature. However, if one redoes the calculation employing costs of \$1.50 per million Btu and 12 mills/kWh for fuel and offpeak energy rather than the \$0.30 per million Btu and 2 mills/kWh assumed in the reference, it becomes advantageous to operate the cavern at 350 C rather than at 49°C. The effect of operation at that temperature, and particularly of cycling to that temperature, was not taken into account in analyzing the characteristics and life of the storage cavern.

The appropriate reservoir temperature for water compensated caverns or aquifer storage is complicated by the effect of temperature on the rate of water evaporation from the storage cavern. The most common approach seems to be to limit the maximum air temperature to approximately 50 C, so as to limit the transfer of heat to the water in the lower reservoir, and thereby to reduce the evaporated losses in a hydraulic system. It has also been suggested that to avoid fracture of concrete linings and grouting in the storage volume the temperature of 50 C not be exceeded (Ref. 13).

Because of the high pressure to which the water in the storage volume is subjected, it is of course possible to heat it above 100 C without the onset of boiling. For this reason it has been suggested in one scheme (Ref. 16). In that case, the water picked up by evaporation actually added to the overall efficiency of the system by increasing the mass flow through the turbine. However, it is of concern that the superheated water, upon ejection from the cavern, may provide an exaggeration version of the champagne effect, and that storage temperatures as high as 180 C may not in fact be feasible (Ref. 67). Aquifer storage lacks this complication, but the question of the rate of inflow of water to the aquifer to replace evaporative loss and questions of cementation due to mineral deposition and oxidation of minerals in the ground water may complicate the operation of aquifers at elevated temperatures.

For dry rock the maximum temperature of 200 C has been proposed as an upper limit (Ref. 60). It seems probable that the upper limit of the temperature is a less critical criterion, but the frequency and range of temperature cycling may in fact be the critical parameter in the operation of the storage cavern.

RESERVOIR PRESSURE

At least the following factors play a role in determining the optimum pressure for the operation of an air storage cavern:

- Pressure capability of the turbomachinery
- Cost of construction of the cavern and shaft, and quantity of energy to be stored

- Load bearing capability of the rock formations
- Characteristics of the excavation technology
- Depth of suitable formation or pressure in the formation

Each of these factors will be considered in the following paragraphs.

An examination of Table 2-2 suggests that, at least in the recent literature, operating pressures of 40 to 50 atmospheres have become the consensus. It has been asserted repeatedly that pressures in this range represent an overall economic optimum for the construction and operation of energy storage (Refs. 40 and 59). However, pressures ranging all the way from 10 atmospheres (Ref. 26) to 90 atmospheres in an unfired cycle (Ref. 30) have been proposed. The pressure cited in Table 2-2 for aquifer storage is one example of the range of pressures determined by the characteristics of the formation used for storage.

Both compressor and turbines must be matched in outlet and inlet pressure, respectively, to ensure effective compressed air energy storage. Today's conventional gas turbine technology employs inlet pressures of 10 to 11 atmospheres, and this may extend in the 1980's to 15 to 20 atmospheres. One manufacturer is already offering a multiple-shaft turbine with a 15:1 pressure ratio. To enable such turbines to operate with a cavern containing compressed air at 40 atmospheres or higher, a number of options are possible. One option is to employ a fired turbine operating at a fixed higher pressure, say 40 atmospheres as in the case of the NWK facility. The availability of commercial equipment of this sort may determine the selection of operating pressures in future compressed air storage facilities. Another possible approach (Ref. 16) is to employ an expander turbine to interface between the combustion turbine and the cavern. Such an approach would require either storage of hot gas, the use of heat storage, or the design and construction of a high-pressure regenerator. It should be noted that the last approach, the design of a high-pressure regenerator, is indicated in the studies by RWE to be the most economical route (Ref. 38). The economics of designing and building specific expander turbines to match particular formation pressures to the inlet pressure of conventional combustion turbines remain to be established.

Another approach, which in fact will be employed in the NWK facility, is storage at pressures exceeding those of the maximum inlet pressure of the turbomachinery, and throttling from the high pressure to maintain a constant lower inlet pressure to the turbomachinery. This approach has the disadvantage of the expense of high-pressure compressors and the loss of additional compressor work, with a reduction in overall efficiency. There appear to be no problems in matching industrial compressors to the pressure requirements currently foreseen for compressed air storage caverns. It has been suggested that there is a minimum in the cost of the turbomachinery at a storage pressure of about 40 atmospheres for compensated storage (Ref. 59).

The ability of rock formations to withstand the total pressure exerted by the gas stored in the formation does not appear to represent a limitation for any foreseeable pressure. Salt caverns and aquifers are now operated for natural gas storage at maximum pressures in excess of 200 atmospheres. Allen (Ref. 60) points out that for an uncompensated system the storage pressure must be well below the weight of the superimposed rock. To lift a column of rock containing water requires a pressure at a particular depth corresponding to 1.0 to 1.1 psi/ft (Ref. 48). This places an upper limit on the maximum reservoir pressure in an aquifer or salt formation, although higher pressures may be acceptable in extremely tight crystalline rock (Refs. 14 and 28).

It is a practice in the natural gas storage industry not to exceed maximum pressures corresponding to a pressure gradient of 0.7 psi/ft, and this seems a reasonable guide to compressed air storage pressures in aquifers (Ref. 48). The maximum pressure in compensated caverns cannot exceed that corresponding to a gradient of 0.43 psi/ft if fresh water is the pressure compensating fluid, or 0.52 psi/ft if saturated brine is employed, since the maximum cavern pressure is determined by the height of the water leg. An area that may require further examination is the relationship between the maximum pressure in the storage chamber and the leakage rate increase from the storage chamber.

The excavation technology employed may have specific depth limitations which in turn provide limits to the pressure range useful for storage prepared by that technology. For a nuclear excavation the minimum head is established by the minimum implant depth; for a 100 kt explosive a minimum implant depth of about 460 meters, corresponding to about 45 atmospheres is required (Ref. 26). There may also be depth limitations set by the need to lower and recover large pieces of excavating equipment. There appear to be no depth or pressure limitations, at least to a depth of 1000 meters, for caverns prepared by solution mining from salt.

The interrelationship between the depth of suitable rock formation, the cost of cavern excavation, and the turbomachinery capabilities has been frequently pointed out. Rogers and Larson have suggested that different turbomachinery manufacturers may in the future compete for a compressed air storage job on the basis of the pressure characteristics of their equipment and the particular geological situation prevailing at the site (Ref. 62). In a hydraulically compensated system, if the inlet pressure is set at 40 to 50 atmospheres, then the depth at which the suitable rock must lie is 400 to 500 meters. However, a greater flexibility in the depth of suitable rocks is possible with dry storage schemes and perhaps with aquifers. Brown (Ref. 14) has pointed out that with hydraulic compensation the pressure store at 215 meters would be operated at 21 atmospheres, while the same store could be operated dry at a maximum pressure of approximately 50 atmospheres. The relationship between reservoir pressure and depth for depleted oil and/or gas fields and aquifers is not as simple as would be suggested by the straight proportionality of 0.1 atm/m. In Figure 2-1 the maximum pressure is plotted as a function of depth for some giant gas storage reservoirs in the United States. The straight line corresponds to a slope of 0.098 atm/m.

When one looks at a particular storage pressure, however, the range of suitable depth is rather large. For the 45 to 50 atmospheres storage the depths vary from 450 meters to about 1000 meters. Thus, it appears probable that for storage in aquifers pressures significantly less than that corresponding to the 0.1 atm/m proportionality may be employed. This may give greater flexibility to the aquifer turbomachinery combination than is the case with hydraulically compensated storage. Because of the possibility that salt caverns may begin to reseal themselves if kept permanently at pressures below those corresponding to the 0.1 atm/m, the question of the lower limit for the operating range of salt caverns should be carefully examined.

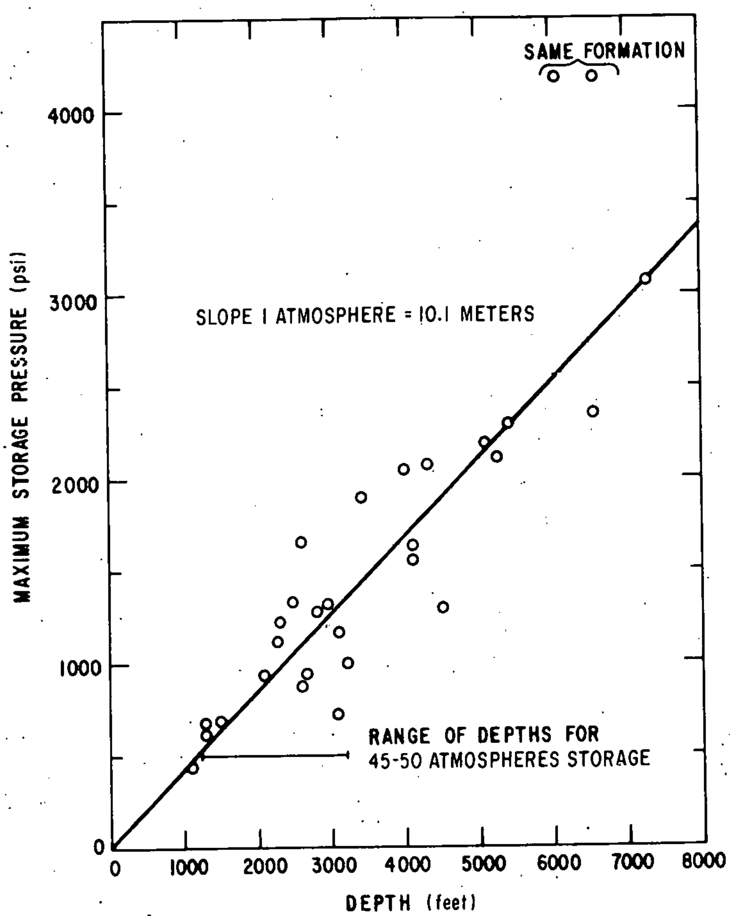

Figure 2-1. Maximum Storage Pressure vs Depth for 33 Giant Gas Storage Reservoirs in the United States (Ref. 31)

EFFECT OF PRESSURE AND TEMPERATURE CYCLING

The only report of a consideration of the effect of pressure cycling on specific reservoir performance has been made in connection with the planning for the NWK facility (Ref. 42). As a result of petromechanical investigations carried out by consultants at the University of California at Berkeley and the

University of Clausthal-Zellerfeld, a maximum rate of depressurization of 10 atm/hr was determined to be within safe limits. This, of course, was for rock salt of the particular mechanical properties prevailing at the Huntorf site. Herbst has also reported that cycling of the NWK salt caverns between 20 and 50 C is within safe limits (Ref. 42), but the basis for this conclusion has not been discussed in the literature.

Further analysis of the literature of rock mechanics should be made to determine pertinent data for both salt and crystalline rocks as well as for sedimentary rocks. Studies have been reported of the separate effects of temperature and pressure cycling of certain crystalline rocks. For wide pressure variation in uncompensated granite caverns, the fatigue life of the cavern walls may be comparable to the lifetimes expected of the compressed air storage facility (Ref. 32). This experimental work should be extended to other rock types that may be suitable compressed air host formations. However, its translation to the actual performance of caverns will be complicated by the nature of the fissure and stress patterns in the formation at the particular site.

The effects of temperature cycling on crystalline rocks has also been the subject of limited experimental investigation. The results have been encouraging in that damage has been found to level off after approximately three cycles, and the network of surface cracks does not coalesce to the extent that the surface crumbles (Ref. 65). The potential effects of residual stresses in rock formation and of cyclic water erosion in compensated caverns must be considered in assessing the implications of these findings to compressed air storage. If rock may be considered to be a representative ceramic material, then the number of cycles to which the rock is subjected may not be the important factor; instead, the time spent at stresses above the critical level and the humidity content of the atmosphere during the stress period may be crucial. It is probable for all practical temperatures of storage in crystalline rocks other than salt that the temperature of the rock will be too low to have any appreciable effect on the ductility of the rock.

For a compensated storage system in which air is admitted into the cavern during charging at 50 C, resulting in compression of the rock, and water at 10 C is admitted in the cavern during discharging, resulting in tension on the rock walls, it has been proposed that the result will be the opening of the previously existing fissures (Ref. 13). For the case considered, the heating from 10 to 50 C results in compressive stresses which reach about 40 percent of the compressive strength of grouted granite. These are sufficiently large stresses, particularly the tensile stress, that considerable degradation in the cavern walls might be expected, depending on the initial surface conditions.

Before proposing cycling over wider temperature ranges or at more rapid pressure loadings or unloadings, a careful examination of the mechanics of the particular formation being considered may have to be conducted. Furthermore, the treatment referred to (Ref. 13) considers granite as a homogeneous material, not taking into account the differential thermal expansion of the various constituents of the rock. This factor needs to be considered in evaluating the range of effects of temperature cycling on crystalline rock.

LEAKAGE FROM RESERVOIR

In many studies, the effect of leakage is either ignored, assumed to be zero (Ref. 62), or declared not to be a serious concern (Refs. 42 and 50). In the last instance there is perhaps justification, since the integrity of salt domes to gas leakage has been well established. Some field trials have been carried out, as for example in unlined test galleries in Wales, which showed that the leakage was "satisfactory" (Ref. 14). The design of excavated hard rock caverns and the manner of their excavation have been related to possible leakage in some cases; if tunnels made by blasting in the rock are to be employed for storage, it has been recommended that they be arranged in a grid side by side (Ref. 58). It has also been proposed that small shafts be drilled horizontally over the air storage structure and filled with water to form a water curtain over the cavern, thus reducing the air loss. To reduce the fracturing of the tunnel surface for the proposed RWE facility, it is planned that blasting not be employed, but that instead a tunnel boring machine be used (Ref. 50).

The most extensive investigations of possible leakage from hard-rock air storage caverns appears to have been carried out in Sweden. Olsson assumes in his analysis of a proposed storage scheme that one percent leakage in 24 hours occurs from the cavern because of the cracks existing in good-quality crystalline rock and that 2 1/2 percent leakage in 24 hours will result from the solubility of air in water. The leakage is taken into account in the design of the facility by adding 3 1/2 percent to the calculated required compressor capacity (Ref. 59).

The loss of stored air through its dissolution in the water stored in the cavern gives rise to another potentially serious effect in hydraulically compensated systems, called the champagne effect. This results from the coming out of solution of dissolved air during the charging of the cavern when the air-saturated water is pushed up the hydraulic leg. Decreasing pressure on the air in the water, will cause bubbles of air to form in the water, and because of a difference in density they will begin to rise in the column. In extreme cases this will result in a breaking of the water column, causing a pressure drop on the air in the cavern that can lead to a catastrophic evacuation of all the air contained in the storage vessel. Olsson proposed to oversize his compressor by 1 to 4 percent to compensate for the drop in pressure due to the water coming out in the hydraulic leg (Ref. 58). Lenssen, however, has proposed a number of rather elaborate measures for controlling this effect: constructing a siphon between the surface reservoir and the inlet neck, constructing a gated overflow tower in the water reservoir in the surface, or providing a valved air pressure chamber to control pressure fluctuations in the hydraulic leg during charging of the cavern (Ref. 50). Olsson has also suggested that the hydraulic leg be enlarged to 12 meter diameter rather than the 6 meter diameter included in his analysis, to minimize the pressure drop due to water coming out of solutions (Ref. 59). Probably because of the large increase in capital cost that such a measure would lead to, Lenssen did not appear to consider this approach.

The most extensive discussion of the problem of leakage from a hard-rock excavated storage cavern is contained in a paper by Berg and Noren (Ref. 13). They assumed specific fissure sizes in the rocks and a situation with no impermeable sealing layer above the storage chamber. Because the pressure at the top of the chamber will always be greater than the hydrostatic formation pressure, leakage from such a storage chamber is inevitable. They considered a case in which the pressure difference between the hydraulic formation and the air storage was 1.5 atmospheres. (It might be noted that in the RWE system, this pressure difference will be 0.55 atmospheres.) Under the circumstances proposed by Berg and Noren, air will gradually displace water in the formation above the storage cavern, to produce a dry zone through which air will continually leak out. The effect of ground water is at first to delay the loss of air from the storage cavern, but ultimately its effect is to compress the flow field of the escaping air. According to the results reported by Berg and Noren, leakage from a continuous tunnel in good water-saturated granite will be about 2 percent in 24 hours, while from a tunnel grid the leakage would be of the order of 1.25 percent in 24 hours. The corresponding leakage from a dry rock tunnel would be about 5 percent in 24 hours.

The question of the extent of the leakage to be expected from compressed air storage in various types of rocks needs more attention than has been given to it to date in the literature. In particular, the effect of temperature and pressure cycling on the leakage rate from excavated hard-rock caverns appears to be a question of considerable importance to the economics of systems employing such caverns.

SURFACE EFFECTS OF AIR STORAGE

This topic has received little attention in the literature to date. German law requires that the NWK powerplant be located at least 100 meters away from the spot on the surface directly above the cavern. Berg and Noren (Ref. 13) have briefly considered possible surface effects from the leakage that they calculated; for example, for rock with homogeneous fissures and a storage cavern consisting of a single tunnel, 90 percent of the air leaking from the storage cavern will come out in an area whose breadth is equal to the tunnel's depth. For a tunnel at a depth of 450 meters, a minimum area of about 200,000 m^2 at the earth's surface would be affected by the escaping air. In this affected area, the surface runoff due to rain would be unusually great because of the inability of ground water to descend into the soil. Where there is loose soil there should be cratering in the affected area; where there is thick clay or where the ground freezes, extreme effects such as blisters and damaging blowouts may occur. Because of the undesirable nature of these surface effects as well as the effect on the overall plant efficiency, it appears highly desirable to employ storage methods that minimize the leakage of air from the cavern.

LEAKAGE INTO RESERVOIR

This effect has not generally been considered significant in analyzing the performance of compressed air storage facilities. A rather unusually detailed analysis of such an effect has been carried out by Herbst (Ref. 35). During each pressure cycle, the air injected into the cavern will pass through the dew point and rain will form. Roughly 1 to 2 m^3 of water will enter the reservoir per cycle. The moisture will collect in the sump at the bottom of the cylindrical cavity. Berg and Noren have also considered the situation in which ground water pressure exceeds the storage pressure and have pointed out that under these circumstances air bubbles may rise through the saturated rock. This leakage represents no fundamental problem with hydraulically compensated systems except as a form of self-discharge and, therefore, inefficiency or loss of performance.

With noncompensated systems, however, this leakage may be a potentially serious problem. If it occurs at a significant rate, the storage chamber would have to be periodically pumped out. Because of the watertightness of salt formations, they should not be susceptible to this form of performance degradation. However, in the case of a throttled, constant volume storage in a porous water-saturated rock such as might be suitable for nuclear excavation (Ref. 26) the effect could be serious. In such a case, when the air caverns were full air would leak out the top of the cavern, driven by the hydraulic pressure gradient between the bottom and the top of the nuclear-excavated chimney. This water would be driven out again during the filling of the cavern; but the rate at which it leaves would be slower than the rate of entry of air into the cavern, because of the greater viscosity of water over air. Overall, the rate of filling will be determined by the shape of the cavern, the permeability of the formation, and the integrated average pressure in the cavern.

CARRYOVER FROM RESERVOIR

The carryover situation has been discussed for three cases: salt carryover, water vapor carryover, and radiation carryover from nuclear mine storage. It is claimed that six months after nuclear excavation of the cavern the short-lived radioisotopes will be sufficiently decayed that the cavern can be operated without concern for carryover of radioactive materials (Ref. 26). In only one case has the carryover of water from a hydraulically compensated storage apparently been explicitly included in the calculation of cycle efficiency (Ref. 16).

Because of the serious effect that alkali metal salts such as sodium chloride have on the corrosion of gas turbine buckets the problem of carryover from salt caverns has received somewhat greater attention. Luthi (Ref. 51) reports that laboratory experiments show that the carryover under the conditions prevailing in the NWK plant will be negligible, but the details of these experiments have not been described. Herbst (Ref. 42) reports the same results, presumably based on the same set of experiments, and asserts that less than 0.1 ppm of NaCl will be carried over from the cavern into the inlet of a gas turbine. The intake for air in the NWK facility will be located 150 meters above the sump and 20 meters from the cavern walls; the air velocity at the wall surface at the maximum rate of discharge will be about 20 cm/s. Thus, the mist in the cavern near the intake is likely to be pure water from moisture condensation during compression, and not brine.

Additional attention to the quantitative aspects of NaCl carryover from salt caverns appears justified. One possible approach might be to analyze the NaCl pickup by the glycol absorbers used to strip moisture from the gas stored in the southeast Michigan gas storage plant. An analogous approach might be employed with other gas storage plants to determine the carryover of harmful material such as sulfur and vanadium. This is a problem area requiring experimental as well as theoretical analysis.

SITING REQUIREMENTS

In addition to the availability of suitable salt formations at the appropriate depth for storage, a special siting requirement of a compressed air storage plant employing storage in brine-excavated caverns is a means of disposing of the brine. This was one reason for the location of the NWK plant near the estuary of the Weser River (Ref. 35). Alternatives that have been employed in the United States are to sell or give the brine to a commercial salt or chlorine plant, or to inject the brine into suitable underground formations. The former of these approaches is of rather narrow applicability, and the latter encounters increasing institutional problems because of the concern of contamination of subsurface water (Ref. 43).

The site requirements for a hydraulically compensated storage plant are similar to those for underground pumped hydroelectric storage. The upper surface reservoir must be large enough to prevent surface level fluctuations from affecting the pressure in the cavern more than ±5 percent (Ref. 50). Not only a river (Ref. 45) but even an ocean (Ref. 34) has been suggested as a possible surface reservoir for compensated plants. It has been estimated that a variable-pressure CAES plant will require only 10 to 15 percent of the surface area that a hydraulically compensated plant will require (Ref. 62).

Berg and Noren point out that in preparation of the site for such a plant measures must be taken at the surface to prevent hydraulic fractures due to air escaping from the store -- relief borings, drainage control, and perhaps even pressurization of the ground water (Ref. 13).

Excavation with a nuclear device presents special siting problems. For example, a 100 kt device produces plaster cracking at a distance of 6.5 km. To maintain radiation within one percent of natural background at inhabited locations it would be necessary to locate the plant 10 miles from the nearest permanent habitation. Contamination of ground water during excavation and during operation of a hydraulically compensated plant represents a potential problem. For a nuclear-excavated cavern, uncompensated systems are preferred because they can be located in arid regions of low population (Ref. 26).

2.6 SYSTEM CHARACTERISTICS

ECONOMICS

Numerous estimates of the economic characteristics of fuel-fired compressed air storage plants have appeared in the literature. These evaluations have been made by people who design and build the equipment for such plants, by the engineering firms that would install such plants, by the utility companies that are assessing the state of the technology, and by at least one utility that is in the process of actually building such a plant. One would therefore expect, and indeed one finds that there is a substantial range in the critical quantities needed to evaluate the economic performance of a particular scheme. This can be appreciated by reference to Table 2-3, which compiles data from papers since 1970.

The important factors in the generation cost of electricity of a CAES plant are the capital investment with associated carrying charges, the utilization factor, the life, the cost and efficiency of fuel use, the cost and efficiency of pumping power use, and the operating and maintenance charges. As indicated in Table 2-3, estimates of the cost of the equipment and balance of plant exclusive of storage cavern have ranged from \$36/kW in 1970 to \$102/kW in 1974. It should be pointed out that this high figure in 1974 refers to equipment actually being built for the first air storage plant, and includes some amount for the engineering required to develop the new equipment needed for that plant. It is probably not a valid basis upon which to estimate future costs of turbocompressor equipment for pumped air storage plants.

The estimated cost of the storage cavern has also varied rather remarkably in the estimates of different authors. The estimates for uncompensated storage in solution-mined salt caverns have ranged from \$2 to \$15 kWh. The figures quoted by NWK for their installation in a salt bed at a depth of about 600 meters are \$13.80/kWh. Hydraulically compensated caverns excavated in hard rock are estimated to cost from ~ \$2/kWh to ~ \$5/kWh. A recent consensus for fuel cost of about \$2/MBtu seems to prevail, but there is substantial disparity in the estimated costs of offpeak power, with variation from 2 to 11 mills/kWh. Similarly, estimates of operating and maintenance costs cover a substantial range from 0.3 to 2 mills/kWh. In view of the rapid changes that are taking place within the economy with respect to fuel and raw materials costs, a new and independent assessment of the economic parameters characteristic of various compressed air storage cycles will have to be made.

Table 2-3

CHARACTERISTICS OF COMPRESSED AIR STORAGE SYSTEMS

Reference		Surface Plant \$/kW	Storage \$/kWh	Projected Life Years	Heat Rate Btu/kWh	Compression Energy Factor (Output Energy/ Input Energy)
Kalapasev (47)	1970	50	0.68	-	3960	1.22
Harboe (34)	1971	55	300 to 375	28 to 40	4770	1.32
Fryer (26)	1973	38	5.50	-	5830	1.41
Kalhammer (45)	1974	90	3 to 5	30	-	1.20
Day (16)	1974	85	-	-	4600	1.24
Ayers (12)	1974	56	7*	-	6200	1.28
Giramonti (28)	1974	65	1 to 6	-	4000	1.60
Rogers (63)	1974	92	2.80	-	3860	1.41
Luthi (52)	1975	96	15	-	5560	1.20
Herbst (38)	1975	102	13.80	-	5560	1.20

* Per kW for an aquifer

Another factor of importance in the economics of a powerplant is the time from commitment to build at a site to startup of the plant. This has been estimated to be two (Ref. 59) or three (Ref. 47) years for excavated cavern storage. The NWK plant in salt will require about two years to construct; about five years from the initial planning (Ref. 42). The rate limiting step is the construction of the underground storage.

OPERATION

The normal mode of operation of a compressed air storage plant will be to provide constant blocks of power at peak load periods for a time determined either by demand or by the capacity of the air store. In the case of constant volume plants, it will be possible to operate them past their design capacity for a time, but care must be exercised to leave enough air in the cavern for a subsequent startup if the system depends on the turbine to start the compressor (Ref. 40). If the turbine and compressor have matched flow, it will be possible to operate the unit as a conventional gas turbine after the air store is exhausted. Various mixed modes of operation have also been proposed (Ref. 59).

In contrast to conventional gas turbines, the output of a CAES plant is insensitive to ambient temperature or pressure. However, the compressor efficiency is affected by temperature, resulting in some variability in the time required to fill the storage cavern (Ref. 57). Also in contrast to gas turbine powerplants, a CAES system, because of its relatively high part-load efficiency, can serve effectively as hot spinning reserve. This application does, however, consume air that would otherwise be used for peak period generation (Ref. 34). From the hot idling condition, according to estimates, a plant of the Swedish design could reach 70 percent of its rated output in 15 seconds (Ref. 60). In ordinary operation, however, the CAES system is judged less effective than the pumped hydroelectric in meeting a utility reserve requirement (Ref. 38).

Times estimated for changeover from one mode of operation to another are summarized in Table 2-4. Emergency startup of a CAES system will have a shortening effect on turbine life, just as with a conventional gas turbine. With an SSS coupling between the motor/generator and the compressor, a CAES system provides a rapidly sheddable load during its generation phase of operation (Ref. 57). Another mode of operation is as a synchronous condenser with the compressor and turbine both disconnected from the rotating motor/generator. With the SSS coupling, rather rapid changeover from this mode to the generating mode is possible (Ref. 40).

Table 2-4

STARTUP AND CHANGEOVER TIMES
FOR COMPRESSED AIR STORAGE PLANTS

Reference	Facility	Generation from Standstill		Pumping from Standstill (min.)	Generation from Pumping Emergency (min.)	Generation from Idling (seconds)
		Normal (min.)	Emergency (min.)			
40	NWK plant	11	6.0	6.0	>21	--
52	NWK plant	20	6.0	6.0	16	--
54	NWK plant	11	6.0	6.0	--	--
60	Swedish plant	8	4.0	--	--	15
57	Swedish plant	--	2.5	--	10	--
38	RWE design	7.5	2.5	--	--	--

The initial startup of a CAES system requires special consideration. If the turbine and compressor have matched flows, then the unit can be started as a conventional turbine, the motor/generator brought up to speed and synchronized with the compressor, and the turbine disconnected (Ref. 16). In the NWK plant this is not possible, because the compressors are too small to power the turbines; a special transmission link will be made between the Huntorf site and a gas turbine plant at Emden. Another possibility might be to employ a portable turbine or diesel-driven compressor to partially pressurize the air store and subsequently start the turbine by windmilling in the ordinary fashion (Ref. 59).

Reliability is an extremely important characteristic of a powerplant. Because of the additional controls for the air system a CAES system might be expected to be somewhat less reliable than a conventional gas turbine. However, the fact that the compressor and turbine operations are separated should enhance the reliability during generation over that of a conventional turbine. At present, the reliability of the two forms of peak power generation appear to be comparable (Ref. 60).

2.7 SUMMARY

The potential benefits to utilities of the introduction of suitable energy storage devices have been cited in a number of references (23, 26, and 45). They can be summarized as follows:

- The overall cost of generation during peak periods should be decreased by storing low-incremental-cost energy produced by base-load plants during offpeak periods and providing it to meet the demand at peak periods. The extent to which this benefit is realized will depend on the characteristics of the energy storage device and the utility generation and load characteristics. The generation cost provides a quantitative measure of this benefit.
- Because peak demand is now met by equipment fueled by petroleum-derived fuels, reduced dependence on such fuels should be achievable by the use of stored energy that had been produced from the conversion of coal or uranium to meet peak demand.
- Storage systems may provide a low-cost, effective way to provide spinning reserve and emergency power.
- Air, noise, and aesthetic pollution should be reduced by decreasing the use of dispersed generation plants using fossil fuels.
- Transmission net load factors could be improved by storage near load centers.
- Storage systems may provide improved system stability because of their ability to respond rapidly to change.

From the foregoing literature review it can be expected that compressed air storage should be able to provide the first four benefits under the proper set of economic conditions. However, it is doubtful, because of the special siting requirements, that CAES systems can generally be located near load centers, and the ability to respond rapidly to changed load conditions should be comparable to that of gas turbines. The extent to which existing and projected compressed air storage technology may be able to fulfill these expectations is the subject of Sections 3 and 4 of this report.

In addition to examining the general benefits of energy storage technology, it is necessary to examine the specific advantages and disadvantages of compressed air storage as compared with other alternatives open to utilities now or in the near future.

COMPARISON WITH GAS TURBINES

The gas turbine is the current technology widely used by utilities to meet load growth, especially for peaking. In comparison, the CAES system

- Will require one-half to one-third of the fuel/kWh (Ref. 52).
- Will produce less local air pollution/kWh (Ref. 34).
- Will be insensitive to environmental conditions during generation (Ref. 50).
- Should be quieter than a conventional turbine, since the compressor and turbine are not operating at the same time (Ref. 47).
- Because of the uncoupling of the compressor from the turbine during generation, the output for a given frame size of turbine will be substantially increased (Ref. 34).
- Because both air and fuel can be throttled at part load to give high efficiency, the CAES system can serve well as hot spinning reserve, as compared with a partly loaded gas turbine (Ref. 38).

The principal disadvantages of CAES systems relative to gas turbines are associated with the air store. The need to have appropriate formations at the proper depths limits the siting flexibility of CAES systems. A number of environmental problems may arise, depending on the kind of underground air reservoir employed. The lead time, for construction will be greater than for a gas turbine facility. Because each site will have an optimum pressure ratio, to obtain the optimized system performance a different design for the turbomachinery will be required for each site. Unless standardized components can be used in these designs the capital investment/kW for a CAES system may tend to be greater than for industrial gas turbines. While the component technologies of the CAES system are well known, its peaking plant performance relative to a gas turbine performance is unknown; thus the risk with regard to performance in building such a plant is greater than with a gas turbine plant.

COMPARISON WITH PUMPED HYDROELECTRIC STORAGE

The principal advantage of a CAES system over pumped hydroelectric storage is the greater siting flexibility of the former. Thus CAES systems are potentially applicable in areas where the relief is not sufficient to warrant construction of a pumped hydroelectric plant. The impact on the environment at ground level of a CAES station is much less than is the case for hydroelectric plants. Compared with pumped hydroelectric plants with one reservoir on the surface and one below ground, a water leg compensated CAES system, has a much smaller surface reservoir for comparable depths of storage (Ref. 28). The lead time for the construction of a CAES system may be less than that for a pumped hydroelectric plant.

The CAES system has a number of disadvantages when compared with pumped hydroelectric storage. A principal one is that the CAES system requires the utility to depend on petroleum-derived fuels to meet its peak load. The availability and life of surface-pumped hydroelectric plants are expected to be greater than for compressed air plants. Pumped hydroelectric technology has been in use by utility companies for many years; they are familiar with its characteristics and may feel that the risk involved in building a pumped hydroplant is less than that in constructing a compressed air plant (Ref. 14). Pumped hydroelectric plants have been made with very large storage capacities and may be somewhat better adapted to pumping over weekends or longer periods than are CAES systems (Ref. 34). As spinning reserve, pumped hydroelectric plants appear to be advantageous (Ref. 38). When sites can be found, the generation costs from pumped hydroplants are projected to be lower than from compressed air plants (Ref. 46).

COMPARISON WITH BATTERIES AND FLYWHEELS

The CAES system is in a much more advanced state of development for utility energy storage than are the battery and flywheel technologies. Thus for some years CAES systems should have the advantage that their characteristics will be better known to utilities. Costs projected for batteries and flywheels at present indicate that unless a credit for storage near a load center is extended to these devices, the peak period sent-out costs should be greater than for CAES systems. The principal disadvantages of CAES systems relative to these developmental technologies are in the use of petroleum-derived fuel and the much reduced siting flexibility.

FACTORS IN UTILITY DECISION

From the foregoing discussion it can be seen that a utility's decision to build a CAES system versus some other alternative will depend on a complex set of technical, economic, and social factors. The following is a list of some possible barriers that may have hindered the implementation of compressed air storage. The extent to which these may be valid considerations is discussed in subsequent sections of this report. These barriers may be considered, somewhat arbitrarily, as being characteristic of either the technology or the utility.

Technology

- Despite all that has been written, since no compressed air plant has been put into operation, the technical feasibility of the concept is still subject to question.
- The capital costs of the plant, particularly those of the air reservoir, may be too great.
- The absence of off-the-shelf equipment imposes a delay which may be unacceptable.
- Environmental restrictions or other institutional considerations may impose a limiting barrier.

Utility

- The load curve may be too flat or peak demand may be economically met by existing units, particularly older generation plants.
- There may be insufficient generation capacity in low-fuel-cost base load, particularly nuclear plants.
- Suitable geology for siting a CAES system may be lacking near transmission corridors.
- Sufficiently detailed geological information for the service area may be lacking.
- A technical staff with the appropriate background to plan and oversee construction and operation of a CAES system may be lacking.
- Where either pumped hydroelectric or a CAES system can be sited, the known technology may tend to be selected.
- Fear that fuel to operate a CAES system could be shut off by arbitrary action may discourage acceptance of the scheme.
- Adequate experience with industrial gas turbines may be lacking.
- Priorities for limited capital may preclude building a CAES system.
- Degree of risk in successful completion of underground construction at a specific site may be unacceptable.

The potential barriers related to the technology are assessed in Sections 3, 4, and 5 of the present report; those related to the utility, in Section 6.

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Section 3

TECHNICAL CHARACTERISTICS OF ALTERNATIVES FOR THE IMPLEMENTATION OF COMPRESSED AIR STORAGE

3.1 INTRODUCTION AND SUMMARY

An initial objective of this phase of the study was to analyze the technical characteristics of the major systems required in a compressed air storage plant to determine whether with the information now available any of the design alternatives for CAES systems could be eliminated on the basis of technical feasibility. A number of areas were identified in which insufficient information is available to make a definite statement; none of the major design variants for CAES systems could be unequivocally shown to lack technical feasibility.

A second objective was to assess the state of development of the technologies needed to demonstrate the CAES concept and to identify directions for technology development that could provide improvements in overall system performance. The general conclusion is that with only moderate engineering effort the technology exists in the United States today to demonstrate the technical feasibility of CAES systems. This is true of all the major subsystems that make up a CAES system. Because of the variability and site specificity of geological conditions, however, the risk of technical failure associated with the creation of underground storage is greater than the risks ordinarily incurred in the construction of utility plants. The development of technology to reduce that risk could have an important benefit in accelerating the use of compressed air storage. Since the incentive to develop such technology is a very broad one, applying to all phases of an underground structure, the establishment of the goals for this development was not considered further in this study.

Two potential problems of general significance were identified: the mechanical behavior of the underground storage medium when subject to relatively rapid temperature and pressure cycling, and the effect on the turbomachinery of carryover from the underground storage into the expander train. These problems are discussed in Section 9 of this report.

The major component subsystems of a CAES system are:

- Compressor train, including inter- and aftercoolers and water separators
- Expander train -- regenerator(s), combustor(s), and expander turbine(s)
- Motor/generator and couplings

- Switchyard and transformer facility
- Electrical, mechanical, and airflow control subsystems
- Auxiliary support systems -- e.g., fuel supply

In this section of the report, these components have been grouped into three larger sets: turbomachinery, storage, and balance of surface plant. The analysis of the turbomachinery alternatives has been based on the evolutionary development of gas turbine technology from a base case representing the state of the art in 1975. Aspects of some nonevolutionary developments, particularly high compression ratio/high discharge temperature compressors for heat storage combined with compressed air storage, are also considered.

The general conclusion is that the basic turbomachinery technology now exists to demonstrate the concept of compressed air storage employing fuel fired turbines. With a definable and relatively low-risk development effort, it should be possible to implement a technology base for advanced systems that will show both lower sent-out costs and lower fuel consumption than the base case. While more detailed specification of plants adapted to specific sites will be required, no technical barriers to implementation of compressed air storage were identified.

It is difficult to make general statements about the state of the technology of underground compressed air storage because of the determining effect that conditions at the specific site will have on the feasibility of carrying out compressed air storage at that site. The approach followed in this report therefore is to summarize and compare the characteristics and distribution of rock types that are potential hosts for compressed air storage. Of these only certain shales appear to be unsuitable either for constant volumes or constant-pressure compressed air storage without extensive and costly protection of the rock surface.

A number of possible types of storage space are considered: natural caverns, mines, conventionally mined caverns, solution mined caverns, aquifers, and depleted oil and gas fields. The technical characteristics of each are considered in relation to the requirements of compressed air storage. The general conclusion is that only conventionally mined caverns, solution mined caverns, or aquifers offered the potential for widespread implementation of compressed air storage. Depleted oil and gas fields, however, may provide a valuable guide in identifying aquifers suitable for compressed air storage. Because the technical requirements for site identification and exploration are of critical importance to the implementation of compressed air storage, these are discussed here in some detail and a format is provided for identifying the appropriate technologies.

3.2 TECHNICAL CHARACTERISTICS OF TURBOMACHINERY SYSTEMS

The turbomachinery of the CAES system serves as the link between the utility system that supplies and receives the electrical energy and the storage cavity. Clearly, therefore, the characteristics of the turbomachinery must be matched to the characteristics of both of these systems. There are in principle two ways to approach the matching of turbomachinery characteristics to the site specific reservoir characteristics such as pressure, temperature, and volume, and to utility system characteristics such as the ratio of generation and charge time and the required power rating. The first approach would be to start with a clean piece of paper and design an optimum set of turbomachinery components for each installation. Although this method has the merit of providing optimized system performance, it clearly would result in very substantial design and development costs for each system.

To provide a technological base potentially capable of widespread application, the more practical approach is to develop modularized systems based on available designs of compressors and turbines that can be adapted to a wide range of storage and utility system characteristics without requiring major redesign for each system. It is the latter approach that has been followed in delimiting the range of characteristics applicable to compressed air storage.

FIRST GENERATION SYSTEM

For the purpose of reviewing and assessing the characteristics of the alternative turbomachinery configurations, a First Generation Base System has been designed. This base system, shown schematically as Figure 3-1, will identify the components essential to any CAES system and provide a basis for comparison of other arrangements.

The system components are based on current state-of-the-art gas turbine technology. Although some engineering development would be necessary to make the system available, no basic technology research or development would be required. Hence, this base system represents minimum development risk, development cost, and lead time approach, based on the axial flow compressors and turbines that are components of the industrial gas turbines now in use by utilities. This establishes a set of basic characteristics in terms of pressures, flows, and temperatures for the system that are quite representative of the current capabilities of gas turbines. The selection of these components should not limit the generality of the study conclusions. A representative set of the component design characteristics is shown in Table 3-1. These are similar to the design characteristics of the General Electric MS 7001 gas turbine.

Compressor Train

It is essential in the design of a normal gas turbine that the airflow capability and pressure ratios of the compressor and turbine be equal, after allowance is made for pressure losses. However, in CAES systems where the compressor and turbine operations are physically separated, these are no longer absolute requirements. If the charging to generation times required by the utility characteristics are not equal, then it may be appropriate to design the compressor and turbine flows accordingly. For example, a shorter

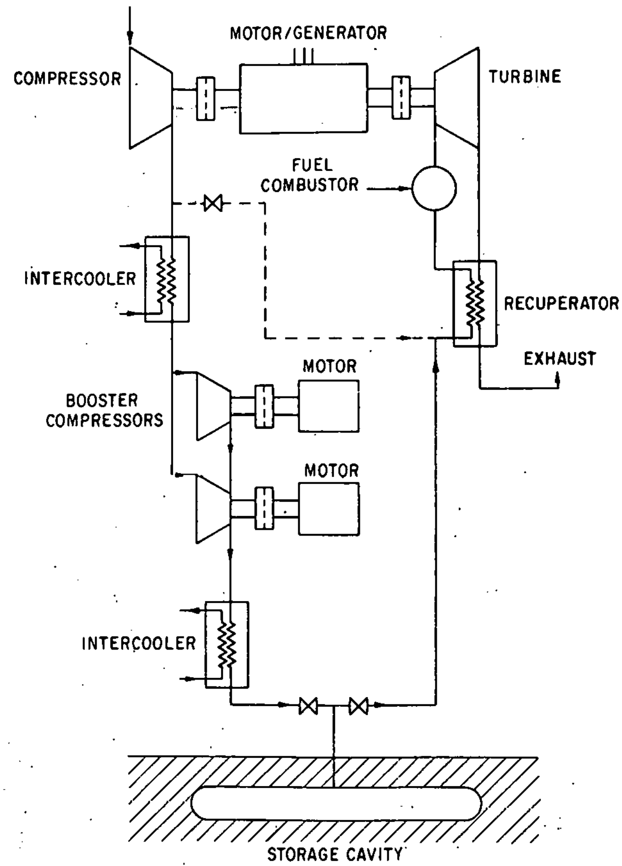

Figure 3-1. First Generation Base System

Table 3-1

ASSUMED COMPONENT CHARACTERISTICS FOR AXIAL COMPRESSOR AND LOW-PRESSURE COMBUSTION TURBINE

Compressor	
Flow rate	2×10^6 lb/hr
Pressure ratio	11:1
Discharge pressure	162 psia
Discharge temperature	630 F
Power input	89 MW
Turbine	
Flow rate	2×10^6 lb/hr
Pressure ratio	10.3:1
Inlet pressure	160 psia
Inlet temperature	1985 F
Power output	150 MW

generation time than charging time requires the flow rate through the turbine to be greater than that of the compressor. However, a mismatching of the main compressor and turbine flow rate has the one important disadvantage that the main compressor and turbine components cannot be operated as a conventional gas turbine. If the compressor is smaller than the turbine, it will not provide adequate air for the turbine to produce power enough to drive the compressor. Conversely, if the compressor is much larger than the turbine, the turbine will not have enough capability to drive the compressor while still producing useful output.

The ability to utilize the system as a conventional gas turbine is important for three reasons:

1. Initial Starting of the System. When the storage cavity contains pressurized air this can be used to start the turbine and compressor system, but prior to the initial charging of the cavity this source of energy obviously is unavailable. Substantial power (in excess of 20 MW) is required to bring a compressor of the MS 7000 size to full speed, even with a fully throttled compressor inlet. With a fully throttled inlet the airflow to the turbine is very low, with the result that the power output is also much less than normal. Hence a large auxiliary starting device would be required to initially start the system.

   Since the main motor/generator is a synchronous machine, it can be used to start the system only if a large and costly controller is provided. If the turbine and compressor have equal flow capability, the system can be started in the same way as a normal gas turbine: with a small starting engine to start the shaft turning, followed by use of the turbine to accelerate the system to synchronous speed. If there are several machines at one site, with at least one matched flow unit, it should be possible to start one machine as a normal turbine and subsequently use the output of this machine to start the other compressors at the site.

2. Failure to Complete Storage Charging. If for any reason the storage cavity cannot be properly charged during the offpeak period, as for example in the event of failure of a booster compressor component, the system could be operated as a conventional regenerative gas turbine at about half the output of the CAES system output.

3. Storage Cavity Failure. Until some experience has been gained on the operation of air storage systems it will be difficult to predict the useful life of the various storage systems. In the event of a premature failure of a particular storage site, the financial risk to the utility would be considerably reduced if the powerplant could continue to be operated, even at reduced output.

Thus, the base system has been selected to have a main compressor and turbine with equal flow passing capability.

The design of the remainder of the compressor train will be dependent on the desired system operating pressure and storage temperature determined by the storage site characteristics. The air discharged from the main axial compressor would be intercooled and then boosted through centrifugal compressors to the necessary pressure to overcome the system pressure losses and permit airflow into the storage. Because of air storage temperature limitations (assumed to be 125 F) an aftercooler is necessary after the last compression stage.

Apart from the selection of the overall pressure ratio, the compressor trains of alternative CAES systems will not vary in significant detail. An exception is the high compression ratio/high outlet temperature required for effecting combined heat and compressed air storage.

Turbine Equipment

The turbine train comprises the regenerator, combustion system, and turbine. Although this CAES system could function without the regenerator, the low temperature of the air leaving the storage would require considerably greater quantities of fuel to be burned if the exhaust waste heat were not recovered. Since the turbine train has an approximate overall design pressure ratio of 11:1, if the storage cavity operates at a higher pressure level, a throttle valve is required to control the pressure at the regenerator inlet.

The turbine module itself is the only major component in the CAES system for which a specific design is not already in place.* However, the design developments that will be necessary to modify an existing design to a turbine module require application of known design principles rather than major technology development. The principal areas where changes are necessary are:

Axial Thrust. Separation of the compressor and turbine will result in unbalanced axial thrusts from the pressure across the turbine. This will require the addition of a balance piston and modified thrust bearing similar to the designs incorporated in steam turbines.

Cooling. The MS 7001, as other current gas turbines, utilizes compressor air to cool the nozzles and buckets in the hottest stages of the turbine. Separation of the compressor and turbine requires the cooling air to be supplied from the storage air supply and the design of a manifold to conduct the air into the rotor. It should be pointed out that one U.S. manufacturer of gas turbines already has a design developed to bring a supply of cooling air into the turbine rotor.

*Brown-Boveri Company is actively developing a design for a plant being built at Huntorf, in Germany.

Casings and Shafts. The separation of the compressor and turbine will require redesign of the turbine casings, shafts, bearings, and seals.

Performance. The design base-load firing temperature of the MS 7001 is 1985 F. At this temperature and at design turbine pressure and flow conditions, the total output is approximately 150 MW. The output can be lowered by reducing the firing temperature and fuel flow, and also by small adjustments to the inlet pressure as shown in Figure 3-2.

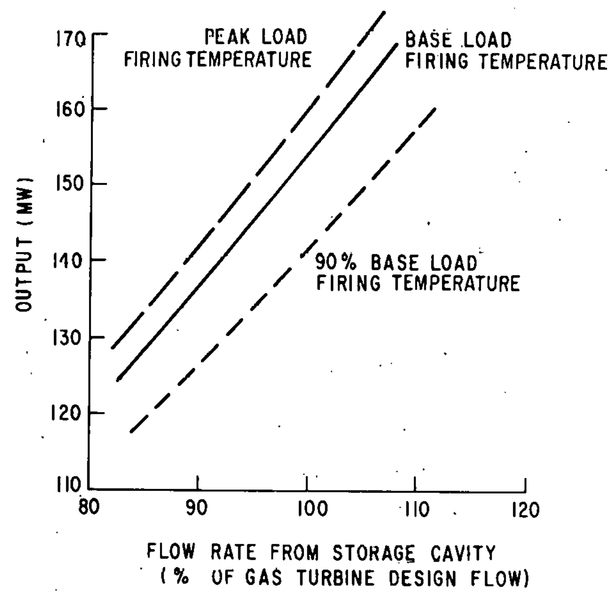

Figure 3-2. Relationship of Flow Rate, Firing Temperature, and Turbine Output

SECOND GENERATION SYSTEM ARRANGEMENTS

Compressor Trains

Upon examination of the compressor train subsystem, two possibilities for system improvements can be seen:

- Simplification of the system by reducing the number of boosters, drivers, intercoolers, etc.
- Reduction of the electric power input required.

System Simplification. To obtain a desired system overall pressure ratio requires increasing the pressure ratio of the individual compressor and elimination of as many booster stages as possible. The maximum pressure ratio of available large axial-flow compressors is approximately 11 to 12:1. One U.S. manufacturer has recently developed a large axial compressor that operates at 16:1 pressure ratio, but this compressor has two concentric shafts, which would prevent its being driven by a single motor. Compressors of the aircraft engine type of gas turbines also operate at higher pressure ratios (up to 16:1), but they have much smaller airflow capability than do compressors of industrial turbines and would not be suitable for the large utility plant requirements.

To increase the pressure ratio range of large single-shaft compressors would require a development program. The probability of the success of such a program in raising the pressure ratio of high efficiency, single-shaft, heavy-duty compressors to the vicinity of 16:1 is very high. Increasing the pressure ratio on one compressor shaft has the secondary benefit of producing air at a higher temperature. This would be of vital benefit in the development of CAES systems that incorporate regenerative heat storage.

Power Reduction. The total power necessary to attain a required system pressure level cannot be significantly reduced except by increasing the amount of intercooling, thus increasing the system complexity and cost. Since centrifugal booster compressors and intercoolers are available in wide ranges of size and cost, it will generally be quite straightforward to tradeoff the cost of compression power against the equipment cost to develop an economically optimum system for specific site and utility situations. Some power reduction can be achieved by increasing the axial compressor pressure ratio while maintaining high efficiency. The axial compressor is more efficient than the centrifugal booster compressors.

Turbine Systems

In systems that have high storage pressures, the total plant output can be increased if the air can be expanded through a high-pressure turbine prior to entering the base system, instead of being throttled to the lower pressure. Use of a high-pressure turbine is limited by the air inlet temperature -- or more accurately by minimum exhaust temperature of the high-pressure turbine. The formation of ice particles in the air and low-temperature strength limitations of the turbine materials requires an expansion turbine exhaust temperature to be kept at least as high as 40 to 50 F (5 to 10 C). This exhaust limit automatically fixes a minimum inlet temperature for any given pressure ratio. Figure 3-3 shows the minimum turbine inlet temperature required for a range of expansion pressure ratios. With cool air storage temperatures (<200 F) high-pressure expansion turbines cannot be used unless heat is added to the air after it leaves storage.

There are three possible ways of adding heat to the air for this purpose:

- Burn additional fuel: in this case the high pressure expansion turbine becomes a high pressure combustion turbine.
- Recover the turbine exhaust waste heat in a high pressure recuperatc
- Utilize stored heat of compression with a regenerative heat exchange

Some combinations of two or three of these methods are also possible.

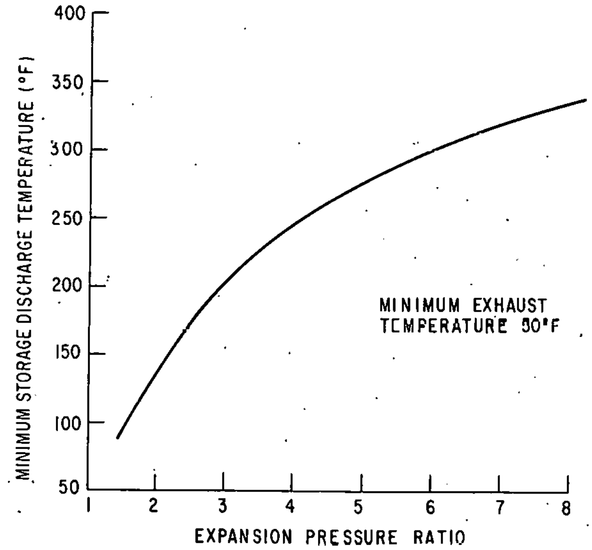

Figure 3-3. Minimum Turbine Inlet Temperature Required by Expander Turbine

High Pressure Combustion Turbine System. Figure 3-4 shows a schematic arrangement of the turbine equipment utilizing a high pressure combustion turbine ahead of the base turbine system. The air leaving the storage system enters a combustion chamber where it is heated to a temperature less than 1000 F and enters the turbine. The turbine exhausts into the conventional recuperator where the low pressure turbine exhaust heat is recovered.

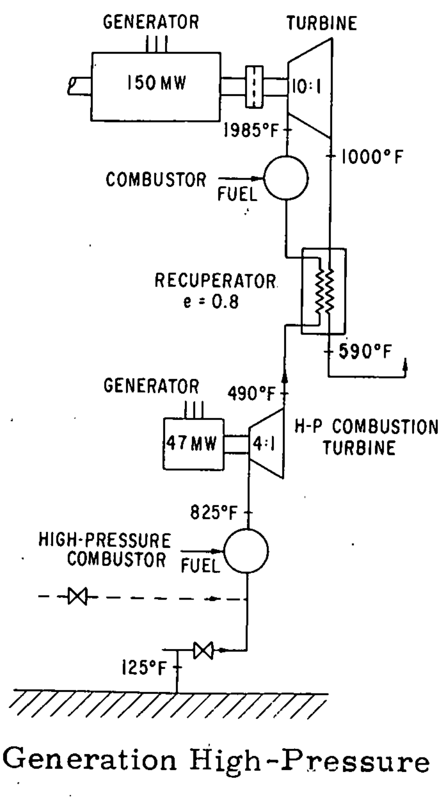

Figure 3-4. Second Generation High-Pressure Combustion Turbine

The high-pressure combustion turbine is shown as a separated turbine generator module. It is also possible to include this turbine on the same shaft as the low-pressure turbine; this would, however, require additional engineering development for the low-pressure turbine module.

This system is similar to that currently being developed by the Brown Boveri Company for the Huntorf plant, in Germany. The major difference is the inclusion of the low-pressure recuperator in this system. The Brown Boveri system does not utilize exhaust heat recovery; their low-pressure turbine operates at a lower turbine inlet temperature (1500 F) than those of the assumed base system given in Table 3-1. This results in a lower exhaust temperature, and therefore there is less heat available for preheating of combustion air through a recuperator.

The highest operating pressure level of land-based combustion turbines designed by U.S. manufacturers is approximately 15 atmospheres. Hence, a major development program would be necessary for any manufacturer in this country to produce suitable combustor and turbine designs. In addition to the high-pressure combustor development, modifications of low-pressure combustor designs would be necessary, since the low-pressure combustor would receive vitiated air from the high-pressure turbine. Although the American gas turbine industry is well capable of undertaking such a development program, the incentives to commit resources to such a development have been lacking.

The design of the high-pressure combustion turbine would be essentially unique to a specific pressure level (45 atmospheres for the Huntorf plant), and a significant amount of redesign would be necessary to modify the combustor and high-pressure turbine if a different overall pressure ratio were necessary.

<u>High-Pressure Recuperator/Expansion Turbine System</u>. Figure 3-5 shows a schematic arrangement of the turbine equipment for the high-pressure recuperator/expansion turbine system. The conventional recuperator, which operates with a pressure ratio of approximately 11:1, is now replaced by a high-pressure recuperator that has a pressure ratio greater than 40:1 across the heat transfer surfaces. This recuperator transfers the exhaust heat from the low-pressure turbine to the air leaving the storage prior to entering the high-pressure expansion turbine. The recuperator is assumed to have the same effectiveness as the low-pressure recuperator (80%); hence, the air temperature entering the expansion turbine is approximately 825 F. The expansion turbine operates on air without any combustion product contamination as in the high-pressure combustion turbine.

Neither the expansion turbine nor the high-pressure recuperator is available as an off-the-shelf design. However, on the basis of discussions with steam turbine and heat exchanger manufacturers, major development programs do not appear to be needed to provide suitable components.

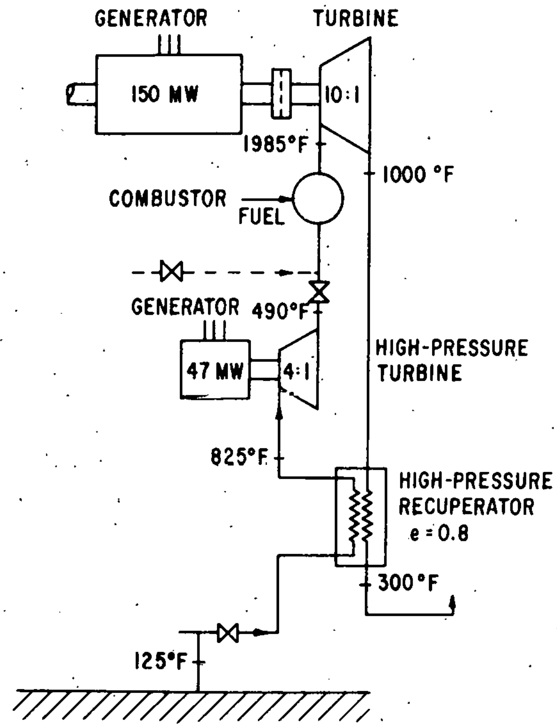

Figure 3-5. Second Generation High-Pressure Recuperator/Expander

PERFORMANCE COMPARISON OF FIRST AND SECOND GENERATION SYSTEMS

A summary of the output and heat rate characteristics of representative first and second generation systems is given in Table 3-2. It should be noted that no attempt has yet been made to optimize the performance of these systems, since specific site data and plant details are unavailable. These performance data serve primarily to indicate the relative differences between the alternative turbomachinery arrangements.

The output of a single base CAES system unit is 150 MW, which is approximately 2.3 times the output of an equivalent regenerative-cycle gas turbine and 2.1 times the output of a simple-cycle gas turbine. This output is

Table 3-2

TURBOMACHINERY SYSTEMS PERFORMANCE

Characteristic	Base	High-Pressure Expander	High-Pressure Combustion	Simple Cycle Gas Turbine	Regenerative Cycle Gas Turbine
Nominal expansion ratio	10:1	40:1	40:1	10:1	10:1
Output, MW	150	194	205	72	56
Air discharge temperature, 125°F					
Fuel flow rate, 10^6 Btu/hr	788	973	1202	814	571
Fuel heat rate, Btu/kWh (HHV)*	5252	5015	5865**	11,300	10,200

* Based on the higher heating value for the fuel.
**Temperature at inlet of high-pressure expander: 1000 F.

essentially constant, regardless of the storage system pressure or temperature, since the turbine inlet conditions are controlled at their normal design point. Thus the effect of increasing the storage temperature to 225 F is to reduce the heat rate of the base system to 5130 Btu/kWh, compared to a heat rate of 5252 Btu/kWh for storage at 125 F. This amounts to an incremental oil saving of 2.32 percent. The effect on the heat rate of the high-pressure combustor cycle is somewhat greater (~ 5 to 6 percent). As noted earlier, the turbine inlet pressure and temperature can be varied to increase or decrease output. The maximum turbine inlet temperature is 2085 F, which increases the output by 4 percent.

The second generation systems utilizing an expander or high-pressure combustion turbine with a 4:1 pressure ratio and inlet temperature of 825 F produce an additional 47 MW, or total output of 197 MW.

As noted in Table 3-2, the fuel consumption for the same output and therefore the heat rate of the base CAES system are considerably lower than those of a simple-cycle gas turbine. On a generated energy basis, the base system consumes 1.04 barrels less of oil than a simple-cycle turbine for each MWh generated. Potential oil savings for the three systems are summarized in Table 3-3. It should be kept in mind that coal or nuclear fuel must be expended to generate the charging power required by the CAES cycle.

Table 3-3

CAES SYSTEMS POTENTIAL OIL SAVINGS

System	Base	High-Pressure Expander	High-Pressure Combustor	Simple Cycle Gas Turbine
Total output, MW	600	600	600	600
Unit output, MW	150	194	205	72
Number of units to achieve 600 MW	4.0	3.1	2.9	8.3
Fuel heat rate, Btu/kWh (HHV)	5252	5015	5865	11,300
Total fuel consumption, $\times 10^6$ Btu/hr	3154	3009	3519	6,780
Oil savings relative to simple cycle gas turbine, bbl/day*	5005	5201	4498	0

*Assumed 8 hours daily operation and 5.8 $\times 10^6$ Btu/bbl.

THIRD GENERATION HEAT STORAGE SYSTEMS

The greatest energy loss in a convention CAES system is in the heat rejected through the compressor system intercoolers and aftercoolers. If this heat could be held in a heat storage medium, it could be used to heat the air on discharge from storage, thereby reducing or eliminating the turbine fuel requirements.

A preliminary analysis has been performed to assess the potential impact of the use of heat storage on the turbomachinery systems. Two cases were examined: 1) the addition of heat storage to first and second generation systems, and 2) the modification of the system to eliminate fuel combustion entirely.

Base System with Regenerative Heat Storage

Figure 3-6 is a schematic diagram similar to the base system shown in Figure 3-1, but with the addition of a heat storage device between the storage discharge and the recuperator inlet.

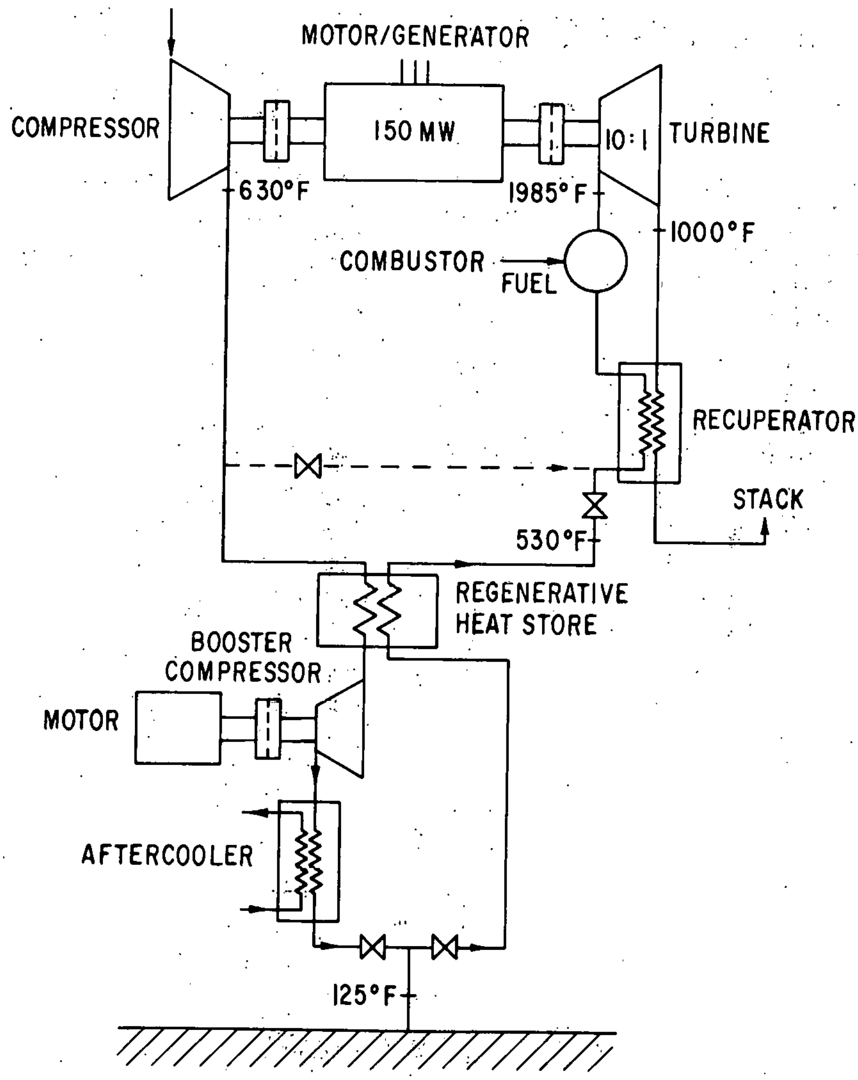

Figure 3-6. Third Generation Base System with Heat Storage

The main axial compressor delivers air at a temperature of approximately 630 F. Thus the maximum temperature at which the air could enter the recuperator is 630 F, assuming no heat losses and infinite heat transfer surface. It has been assumed that heat losses and heat transfer requirements will result in a ΔT loss in the regenerative heat store of 100 F; air would enter the recuperator at 530 F. Preheating the air entering the recuperator results in lower heat recovery in the recuperator and a higher stack temperature, since the effectiveness is assumed to be held constant at 80 percent. The net result is a 10 percent reduction in absolute fuel consumption.

The fuel saving that will be generated by this reduction in heat rate can be converted to a capital cost for the heat storage. Thus for a heat rate reduction of 420 Btu/kWh, assumed fuel cost of $2.0/MBtu, 18 %/yr fixed charge rate, and 8 hr/day operation, an equivalent cost for the heat storage would be $1.9 per kWh of energy stored.

Second Generation System with Heat Storage

For a second generation system with heat storage the regenerative heat storage system replaces either a high-pressure combustor or a high-pressure recuperator ahead of an expansion turbine, as shown in Figure 3-7. With the same compressor discharge temperature, the air entering the expander will now be 530 F, which with a 4:1 expansion ratio would produce approximately 36 MW of power and an exhaust temperature of 270 F.

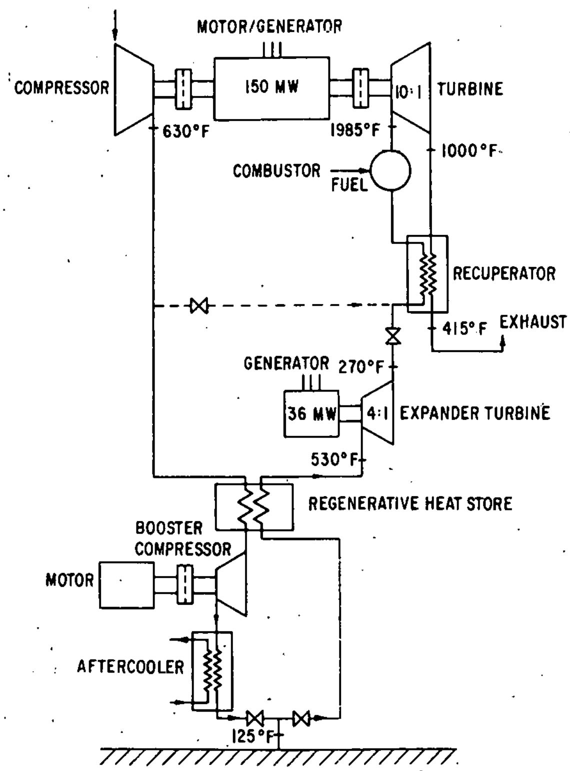

Figure 3-7. Third Generation High-Pressure Expander System with Heat Storage

The absolute fuel consumption of this system is decreased by about 25 percent relative to a high-pressure recuperator and expander system. Comparing Figures 3-7 and 3-5, one can see that although the output of the expander is lower in the former case, this output is obtained without using any of the exhaust heat that is now available to heat the expander exhaust before it enters the combustor. Hence, the combustor inlet temperature is raised and the required fuel flow lowered in the cycle described in Figure 3-7.

The improved heat rate of this system relative to a high-pressure recuperator and expander system is about 730 Btu/kWh. According to the same assumptions previously used, this can be equivalent to a capital cost for heat storage of $3.3 per kWh of energy stored.

Nonfired Systems

In a nonfired CAES system, the maximum turbine inlet temperature would be limited to something less than the maximum compressor discharge temperature. Compressor discharge temperature is primarily a function of the inlet temperature and the overall pressure ratio, assuming constant efficiency. Hence, in order to increase the compressor discharge temperature it is necessary to increase the overall pressure ratio of the compressor — without, of course, intercooling.

Current single-shaft axial compressors are limited to about 11 to 12:1 ratio, and increasing these levels will require major development programs. It is judged that there is a good chance of success in achieving a 16:1 compression ratio machine. For the purpose of comparison only, a system with a 25:1 overall pressure ratio has been included. The magnitude of the development program needed to achieve this pressure ratio had not been characterized. In particular, it is not known that systems of this high pressure ratio can be developed for the large flows characteristic of industrial turbines. Therefore, these systems have been analyzed on a specific output basis (energy/lb of air), and the results could be scaled to any desired airflow and total energy level. Figure 3-8 is a schematic diagram of a nonfired CAES system that is representative of any desired pressure level; Table 3-4 summarizes the most important system parameters for three levels of turbomachinery pressure ratio: 11:1, 16:1, and 25:1.

The compressor and turbine have essentially equal overall pressure ratios, and the system pressure losses are accounted for by adding a small booster compressor. If the system storage pressure is substantially higher than the available compressor discharge, then a larger booster is required. Practical considerations would probably dictate that only the heat from the main compressor can be stored; hence, increasing the booster pressure ratio to anything higher than the minimum to overcome pressure losses would result in additional energy losses and a less efficient system.

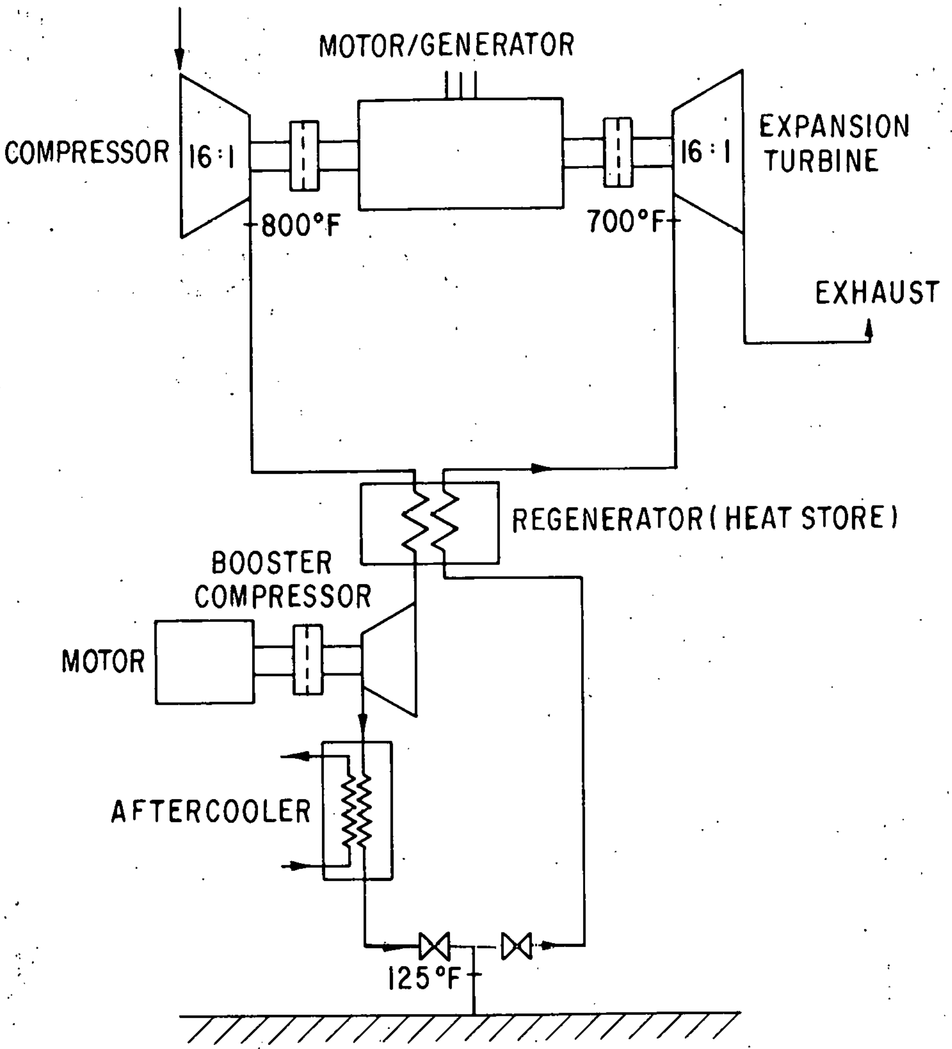

Figure 3-8. Third Generation Unfired Turbine System

Table 3-4

NONCOMBUSTION SYSTEMS PERFORMANCE

Characteristic	Nominal Pressure Ratio 11:1	16:1	25:1	Base System
Compressor discharge temperature, °F	630	800	960	630
Turbine inlet temperature, °F	530	700	860	1985
Turbine exhaust temperature, °F	120	170	194	1000
Specific output, kWh/lb air	0.03	0.04	0.052	0.075
Efficiency, $\frac{\text{output MW}}{\text{input MW}}$	0.59	0.61	0.65	

An alternative approach to elimination of the booster would be to design the main compressor and turbine for different pressure ratios to account for the pressure losses. However, this would result in the need to redesign these components for almost every CAES system, since it is unlikely that any two storage systems will ever have exactly the same pressure losses. This clearly would be a more costly approach.

The most significant effect of a nonfired system would be the much lower specific output than any other system in which a high firing temperature is maintained. Specific output is the output energy that can be obtained from a pound of air, and is strongly dependent on the temperature. As indicated in Table 3-4, reducing the turbine inlet temperature from 1985 to 530 F for an 11:1 system reduces the specific output; the costs will remain constant for a given pressure level and air quantity. Hence, when the output per pound of air is reduced, the specific cost $/kW of the compression and of the storage systems will be proportionately increased.

The unfired turbine design is not available today, but the relatively low temperatures and modest pressure levels (relative, for example, to steam turbines that have inlet conditions of 1000 F and 163 atmospheres) do not pose major technology development problems. Making suitable designs available is mainly a matter of engineering development and design effort. There is a question as to how the system would be started, since the turbine cannot provide enough power to bring the whole system up to speed. Two solutions appear as possible candidates:

- Provide a secondary starting turbine. This would be quite large -- approximately 20 MW for an 11:1 compressor system.
- Provide a supplementary combustion system capable of heating the compressor discharge air to a high enough temperature to bring the whole set up to speed. This would require the development of a high-pressure but relatively low-temperature combustion system.

3.3 CHARACTERISTICS OF BALANCE OF SURFACE PLANT

A completed compressed air storage plant will include an operating area sharing a common boundary with the surface area required for the cavern excavation or compensating lake. To characterize the major systems involved, three alternative methods of compressed air storage were considered:

- At 40 atmospheres in an aquifer
- At 40 atmospheres in an excavated or compensated cavern
- At 40 to 80 atmospheres in a solution mined, constant volume reservoir

Figures 3-9, 3-10, and 3-11 provide diagrammatic layouts for a water compensated cavern plant, an aquifer storage plant, and a solution-mined salt cavern plant, respectively.

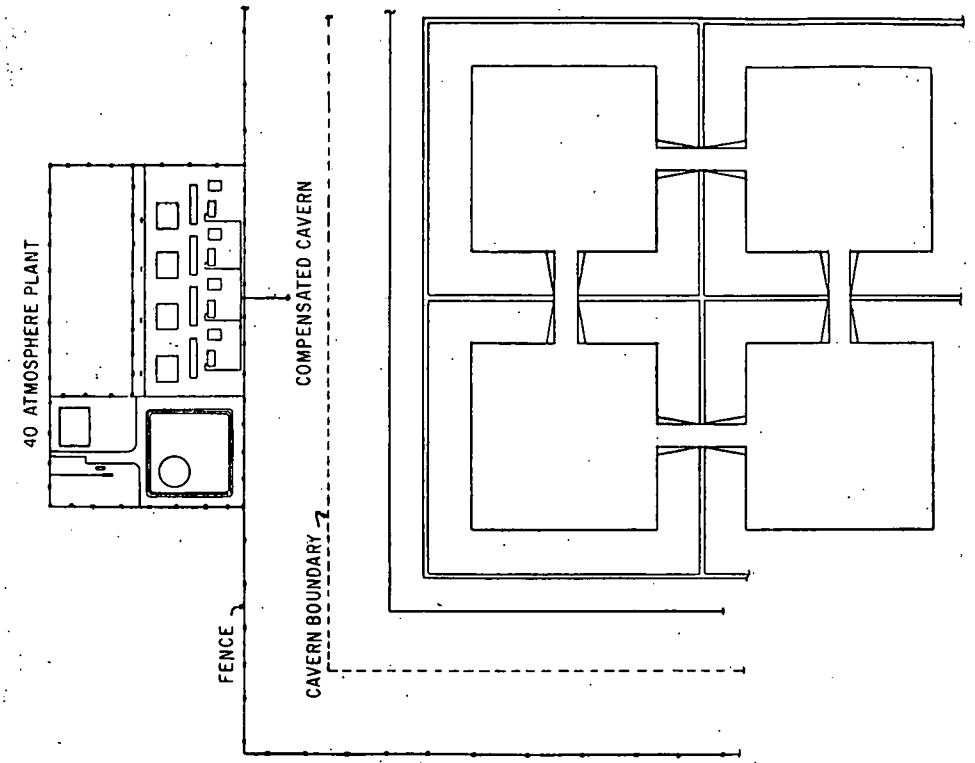

Figure 3-9. 600 MWe Compressed Air Plant Using 40 Atmosphere Lake Compensated Cavern

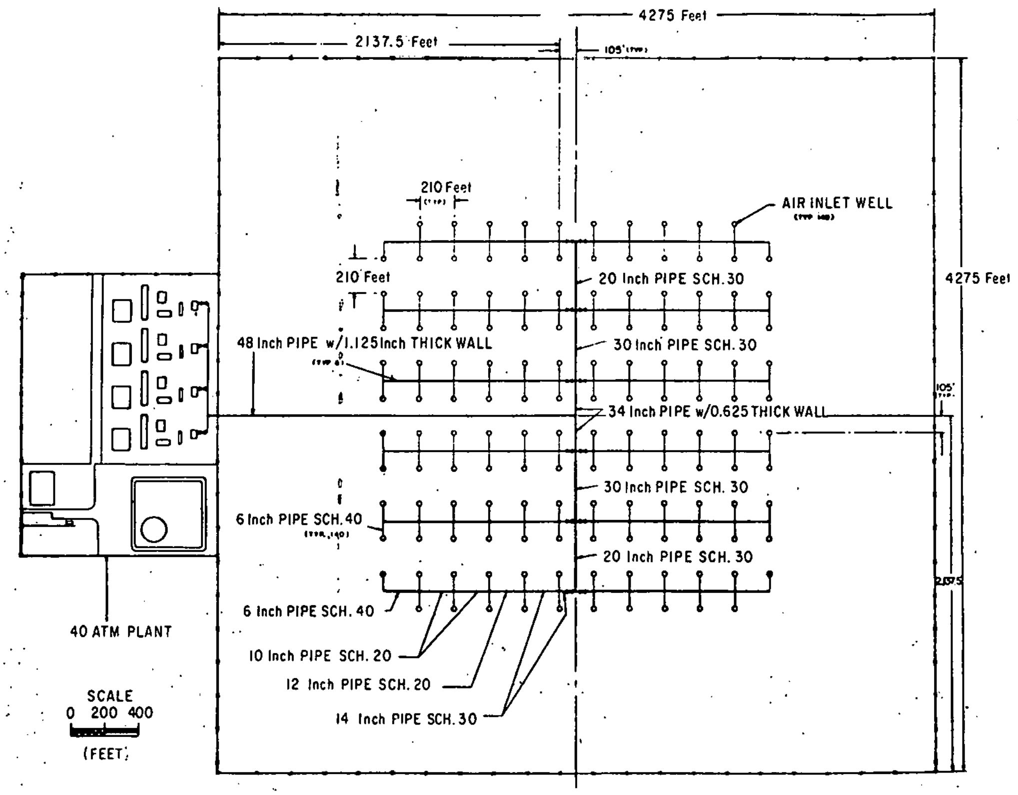

Figure 3-10. 600 MWe, 40 Atmosphere Aquifer Storage Plant

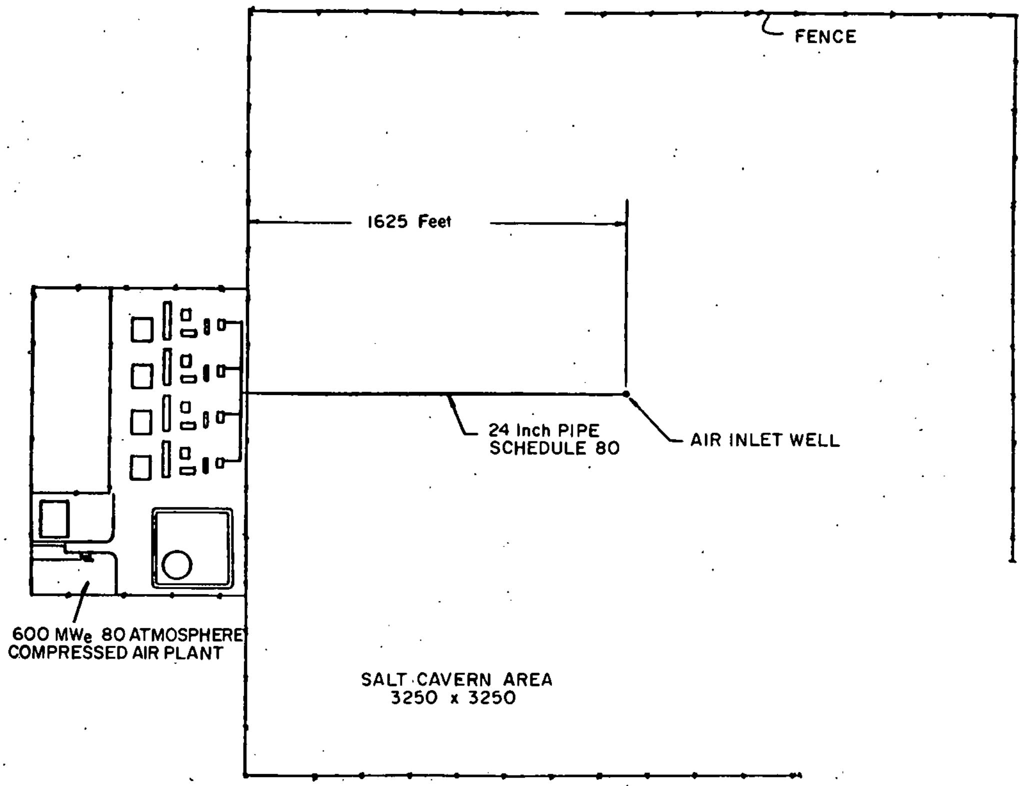

Figure 3-11. 600 MWe Compressed Air Plant Using 80 Atmosphere Salt Cavern

PLANT LAYOUTS

Figures 3-12 and 3-13 are layouts of the 40 atmosphere and 40 to 80 atmosphere surface plants, respectively. Each basic plant has four primary areas, excluding the cavern site: fuel storage, switch yard, turbomachinery, and plant access. Only the turbomachinery area and cavern differ for each alternative compressed air plant. The fuel storage area includes a 5,000,000 gallon fuel tank that holds a 60 day fuel supply. The turbomachinery area has four equipment modules -- each containing the main compressor, turbine and combustor, and all auxiliary compressors and air intercoolers.

A switchyard and a transformer area are located at the generator end of the turbomachinery modules. A single building in the plant access area houses a control room, sanitary facilities for any operating staff, and a spare parts storage facility. A single unloading station supplies fuel to storage tanks from either railway or highway tank vehicles. A road and a railway siding enter the area and provide access to transportation facilities for all plant machinery and hardware.

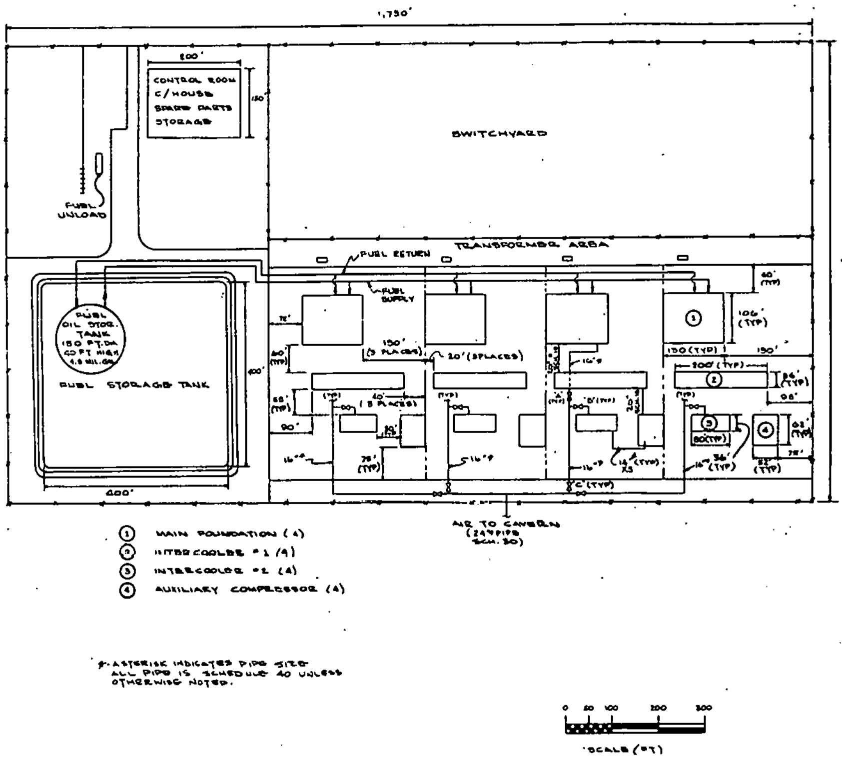

Figure 3-12. Balance of Plant Layout at 600 MWe 40 Atmosphere Working Pressure

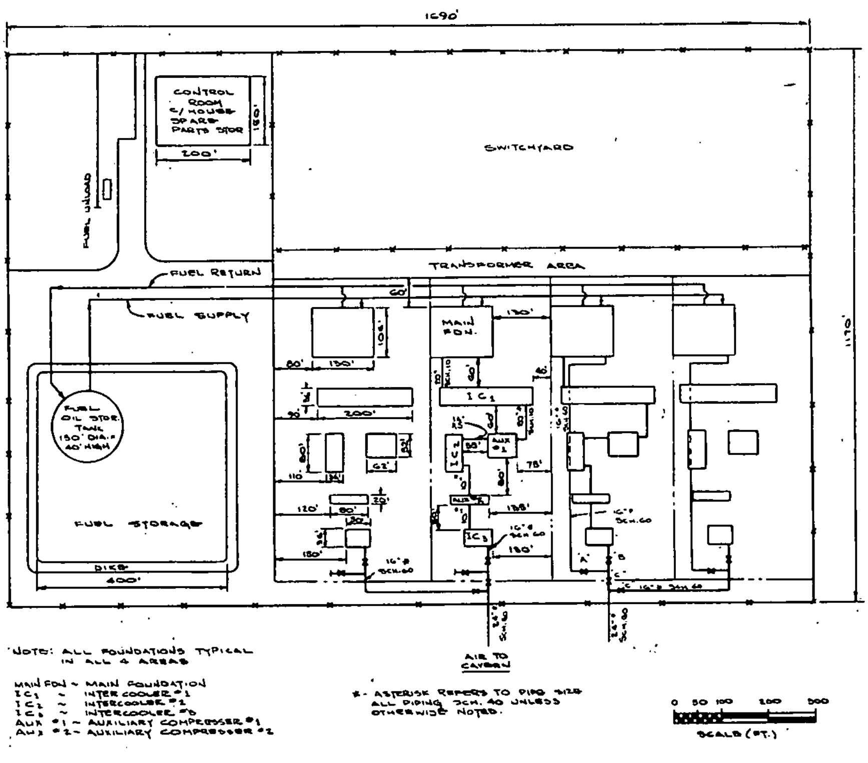

Figure 3-13. Balance of Plant Layout at 600 MWe 80 Atmosphere Working Pressure

TURBOMACHINERY MODULE

The turbomachinery module contains all the electrical generating and air compression machinery. Figure 3-14 shows schematic flow diagrams for both 40 and 80 atmosphere plants. The main foundation is a concrete slab measuring 130 feet by 106 feet and 6 feet thick. It supports the gas turbine/ combustors, motor-generator, main compressor, and the electric lubricant and accessory skids.

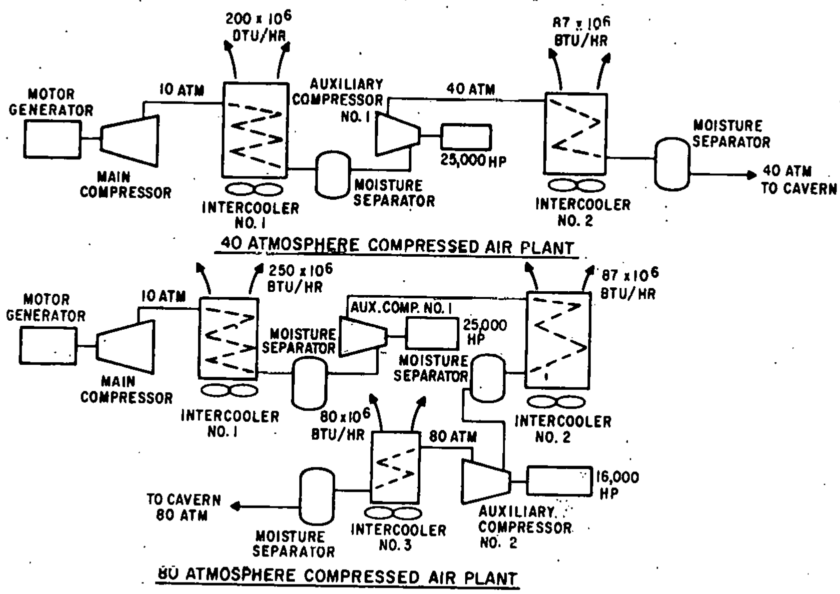

Figure 3-14. Flow Diagram of 40 and 80 Atmosphere Compressed Air Plant

Aircooled heat exchangers are used to cool the air between various stages of compression. Aircooled intercoolers show an economic capital cost benefit over a water circulating system utilizing dry cooling towers; they require no makeup, blowdown, or water treatment system. A wetcooling tower was not considered for this study. An aircooled intercooler also requires less land area, because the heat exchanger and the cooling-medium circulating machinery are an integral unit. Quotations and specification have been obtained from a vendor on three intercooler units: at 150 psia, 600 psi, and 1200 psia. Specifications for use with the 40 and 80 atmosphere plants are as follows:

Intercooler	Heat Rejected (Btu/hr)	Foundation Size (feet)
1	280 x 10^6	200 x 36
2	87 x 10^6	88 x 36
3	80 x 10^6	55 x 36

Two stages of auxiliary compressors provide the proper air storage pressure. Auxiliary compressor 1, used for both the 40 and 40 to 80 atmosphere plants, consists of three compressors in parallel, each driven by a 25,000 horsepower motor on a common slab foundation. The foundation measures 62 by 52 feet and 6 feet thick. Auxiliary compressor 2, used only for the 40 to 80 atmosphere plant, consists of two compressors connected in parallel on a slab foundation measuring 80 by 20 feet and 6 feet thick. Each compressor is driven by a 16,000 hp induction motor.

Air piping is identical for all turbomachinery modules except at the cavern inlet manifold area downstream of the final intercooler. A manifold area is adjacent to the cavern site and positioned as close as possible to the cavern inlet shaft. Piping from the manifold area to the inlet shaft is 24 inch, Grade B carbon steel, selected to reduce frictional losses. A 16 inch pipe connects the final intercooler in each module to the cavern inlet manifold. All piping is located at ground level.

Each turbomachinery module has two electric operator-actuated plug valves that serve as the air shutoff. The plant operator can charge the cavern (valve A open, valve B closed), discharge the cavern and fire the turbine (valve A closed, valve B open) or isolate a particular module and operate the remaining modules (both valves closed). A manual shutoff valve for each module allows complete isolation of the module for removal or repair of either valve A or valve B while still operating the remaining modules. All air shutoff valves proposed for this design are manufactured by the Rockwell Nordstrom Corporation, but alternative manufacturers are known.

All intercoolers and air valves are mounted outdoors. A vendor-supplied protective structure encloses the main compressor, motor-generator, and power turbine. Similarly, a movable unsoundproofed enclosure protects both auxiliary compressors. Foundations are positioned in a typical module to allow 50 to 60 foot clearance around all machinery. This will provide access to all machinery by wheeled vehicles and cranes. A loose crush-stone surface is placed between all the foundations.

Adequate drainage and lighting provisions for the plant are based on recently designed and exected outdoor gas turbine plants. City water is supplied to all necessary facilities.

FUEL HANDLING SYSTEM

A 5,000,000 gallon fuel tank holds a 60 day fuel supply for a 4 hr/day operating cycle plant. The tank is filled from a fuel unloading station that can service highway or railroad tank vehicles. The unloading station is a simple arrangement of flexible hose, valve, and pump. The tank measures 150 feet in diameter, is 40 feet high, and has a fixed roof and a floating suction. The tank is surrounded by a dike 400 feet square that will contain 100 percent tank capacity, to receive fuel from a major fuel spill accident. Lighting, instrumentation, and fire protection are provided, based on past gas turbine plant experience.

Figure 3-15 shows schematically the fuel transfer system. In-line centrifugal pumps, requiring no foundation, transfer fuel to the turbine modules. A fuel heating system is not required, since the fuel is a low-viscosity distillate similar to kerosene or jet engine fuel.

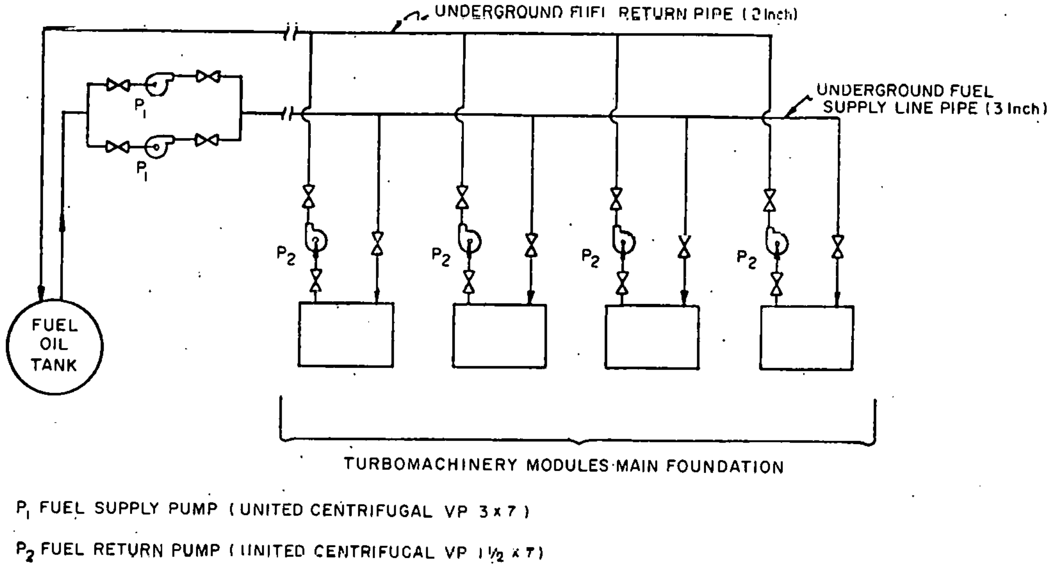

Figure 3-15. Fuel System for Compressed Air Storage Plant

Fuel is pumped through an underground pipeline of 3 inch carbon steel. A spare transfer pump, in parallel with the primary pump, can supply fuel to the turbomachinery modules if the primary pump must be removed. A 4 inch suction line runs from the tank, over the dike, and to the pump inlet. A two inch underground line provides a fuel return line, required for gas turbines; this line is connected to 1-1/2 inch pipe from each turbomachinery module. An in-line pump is mounted in each fuel return feeder line. Valves in each fuel inlet and return feeder allow maintenance on a modules fuel system without affecting fuel supply to other modules.

TECHNICAL FEASIBILITY OF PLANT COMPONENTS

The balance-of-plant components for the compressed air plant described are standard hardware used on gas turbine plants now in operation. Components, provided by a number of American manufacturers, are reliable standard products, easily maintained and proven over many years of gas turbine experience.

However, two components associated with the cavern may pose technical or plant erection problems:

- Aquifer storage will require multiple air inlet wells and a complex pipe manifold, field assembled and fabricated to connect the turbine modules to the aquifer air inlet shafts. Pressure equalization in all inlet wells of the aquifer may pose a problem. Further research programs should investigate inlet well distribution and alternative well and inlet manifold configurations.
- An airborne particulate removal system may require further technical development. Mineral carryover from the cavern may cause corrosion problems requiring special materials. Particulate removal system design should introduce minimal friction losses at the proposed operating pressures. Further development programs may be required to quantify these parameters and find acceptable solutions .

3.4 TECHNICAL CHARACTERISTICS OF UNDERGROUND STORAGE

The large-scale underground storage of gases and hydrocarbon liquids is already a mature technology in the United States (Ref. 12). Large mined cavities are in use for both low-pressure gas (LPG) and natural gas storage (Ref. 8), and aquifers and depleted oil and gas fields are extensively employed for natural gas storage (Ref. 14). In this subsection experience derived from such technology is used to assess the technical feasibility of underground air storage for CAES as well as to characterize the availability of sites for CAES storage in the United States.

Three major differences have been noted between the underground storage of air and that of natural gas:

- The storage of air for CAES requires daily, rather than seasonal, pressure and temperature cycling of the host formation. The mechanical effects of this frequent cycling on the cavern walls can be expected to be more severe than the corresponding effects in natural gas or LPG storage.
- The cost of replenishing air lost by leakage from underground storage is substantially less than that of replenishing a comparable quantity of lost natural gas. If undesirable surface effects are not produced by the air leakage, then formations not suited for natural gas storage may be acceptable for compressed air storage.
- The chemical and biological effects of compressed air are quite different from those of natural gas. Aerobic conditions of storage may induce changes in the host formation, particularly in the case of depleted oil or gas reservoirs.

These differences indicate particular areas requiring experimental resolution to assess the limitations in applying natural gas storage experience to project the characteristics of CAES plants.

CHARACTERISTICS OF ROCK TYPES

The most important geological requirement for siting an underground storage plant is generally the availability of a suitable host formation. The technical and economic feasibility of storage at the site and the mode of storage employed would be determined by the characteristics of the rock formations. Appendix A, "Major Lithologic Environments," comprises a brief review of some characteristics of lithologies that are relevant to air storage technology. A summary of the relevant conclusions is contained in this subsection.

There are large areas in the United States that are considered favorable for the construction of mined caverns (Figure 3-16). Igneous intrusive rocks, such as granite, which have excellent mined openings, are used as host formations for several large LPG storage caverns. Regions of the United States where large outcroppings of these rocks occur (Figure 3-17) should contain sites that are suited on the basis of rock strength to construction of mined CAES air reservoirs.

Massive crystalline metamorphic rocks also are generally excellent for the excavation of conventional caverns. Laminated metamorphic rocks such as schists and slates may be quite suitable, but their strength can vary substantially within a given formation. Sedimentary carbonate rocks such as limestone and dolomite usually have excellent mechanical strength (Ref. 1). Carbonate rocks, however, are subject to chemical attack by acidic water, resulting in the development of channels in the formations. Thick shale deposits occur in many regions of the United States (Figure 3-18), and a number of the LPG storage sites indicated in Figure 3-16 are in shale (Ref. 28). Some varieties of shale are swollen by exposure to fresh water, and this can result in failure of the cavern (Ref. 5). Table 3-5 qualitatively summarizes the comparative suitability of rock types for construction of conventionally mined air caverns.

Thick salt formations occur in several regions of the United States (Figure 3-19). In the Gulf Coast area salt occurs as domes (Ref. 23); elsewhere it occurs in bedded formations (Ref. 30). Both formation types are easily solution mined and represent a particularly valuable resource for the storage of a variety of materials or the disposal of radioactive wastes. Large, conventional mines also exist in these salt formations -- near Detroit, Cleveland, and in western New York State.

In large areas of the United States sedimentary rocks predominate. The large depositional basins are outlined in the map shown as Figure 3-20. In addition to massive carbonate rocks and shale, porous and permeable sandstone and carbonate rocks also occur. These generally will not be suitable host formations for conventionally mined air storage caverns, but they may be of considerable significance for aquifer storage of compressed air. A schematic cross section of an aquifer showing one type of structure, an anticline, needed to trap the air is shown in Figure 3-21.

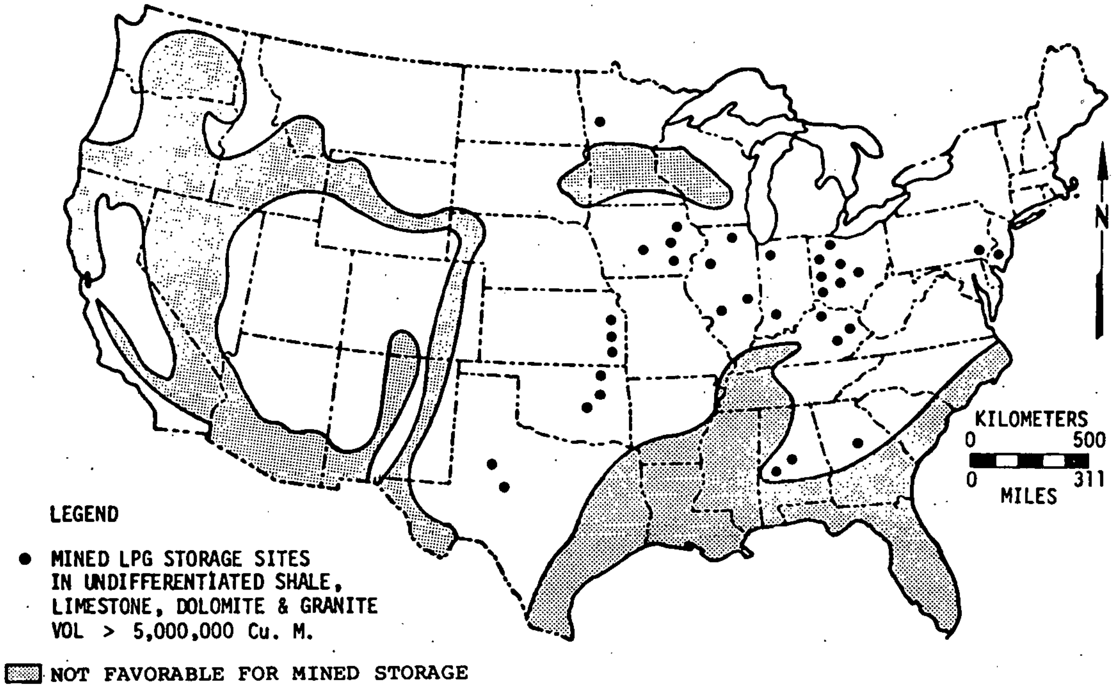

Figure 3-16. Mined Liquid Petroleum Gas Storage Mined in the United States

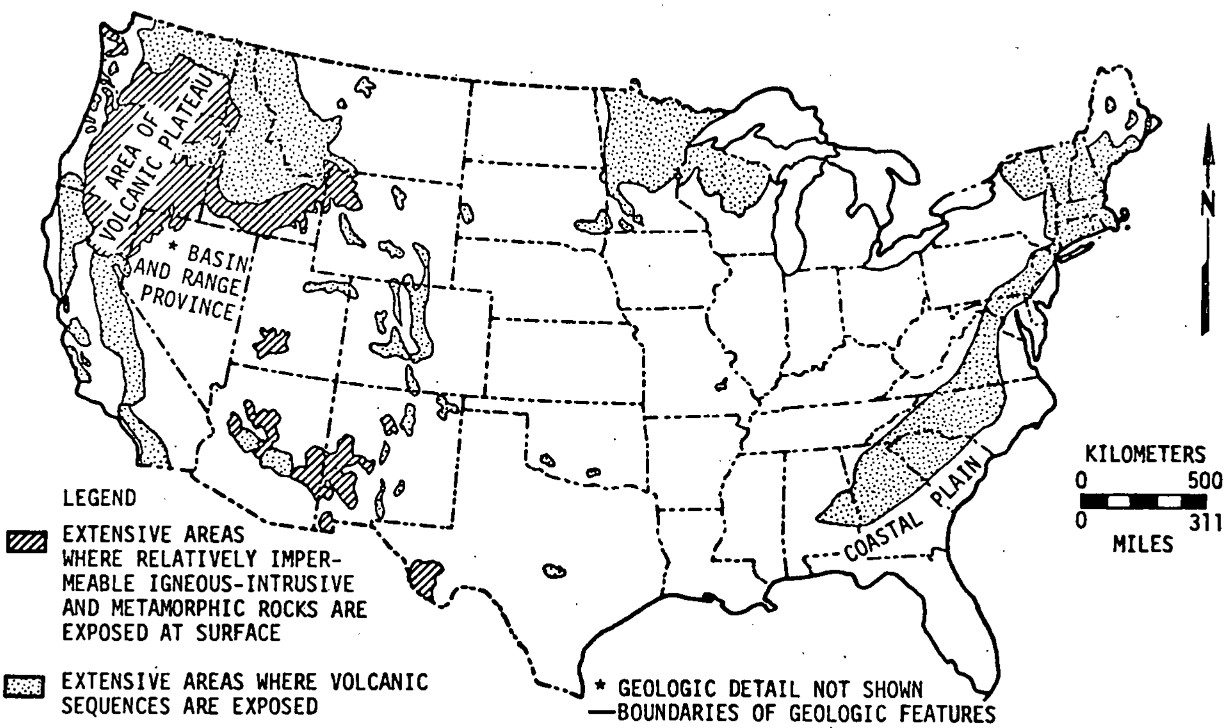

Figure 3-17. Outcrops of Igneous Rocks in the United States

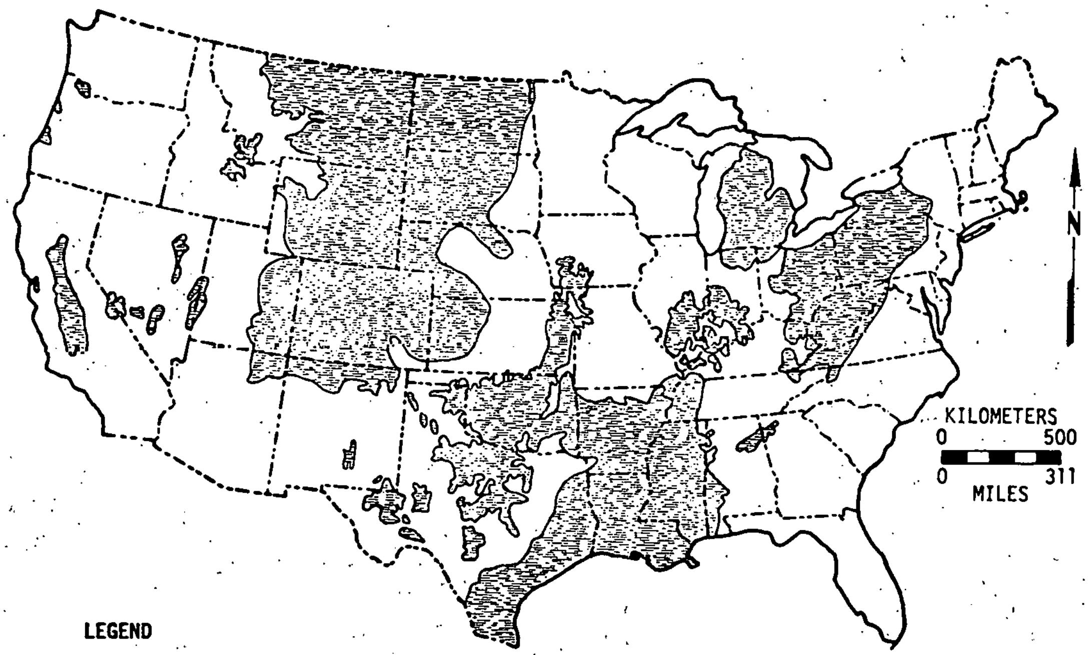

Figure 3-18. Thick Shale Deposits in the United States

Table 3-5

COMPARATIVE SUITABILITY OF ROCK TYPES FOR CONVENTIONALLY MINED CAES CAVERNS

Rock Type	Ranking	Summary
Granite and other igneous rocks	++	Isotropic, high-strength; many LPG storage caverns built.
Crystalline metamorphic rocks	++	Isotropic, high strength; many LPG storage caverns built.
Limestones and dolomites	+	Usually isotropic, medium-strength caverns used for oil storage.
Slates	0	Anisotropic, frequent stability problems; may lend themselves to excavation by boring or other advanced technologies.
Shales	-	Compensated caverns not suitable for montmorillonite containing shales. Noncompensated caverns may have slacking problems. Oil storage is done in shale caverns. Air storage may be 2 to 4 times more costly in shale than in granite.
Sandstones	--	Need a confining impermeable layer to control stored air.

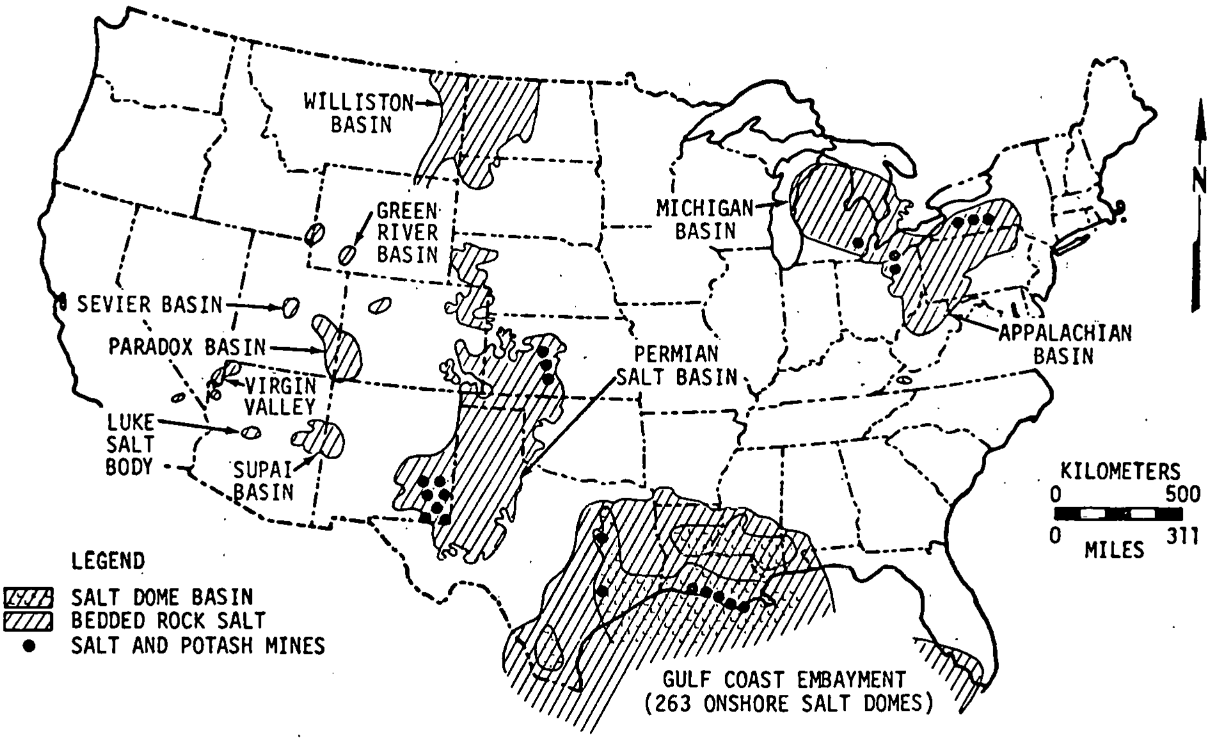

Figure 3-19. Major United States Salt Deposits and Mining Localities

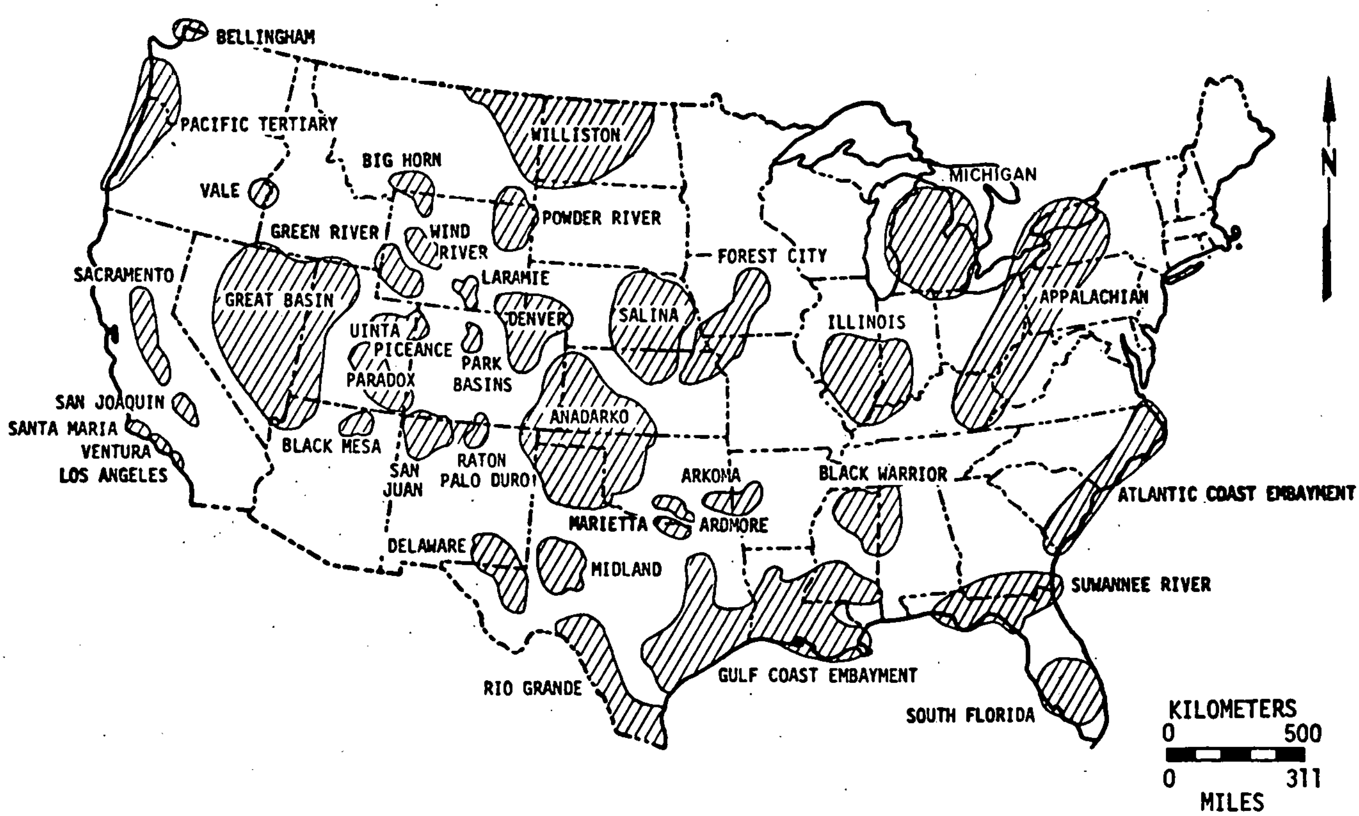

Figure 3-20. Major Depositional Basins in the United States

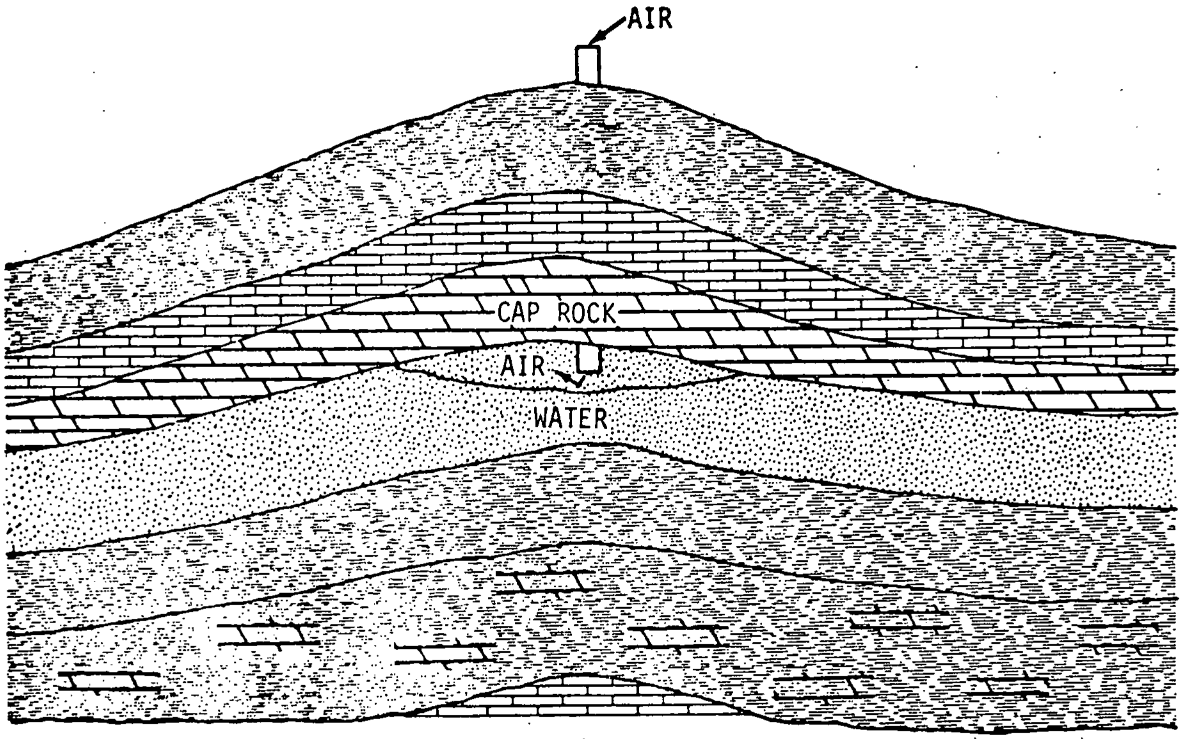

Figure 3-21. Theoretical Sandstone-Anticline Suitable for Compressed Air Storage

Such structures are generally associated with the conditions needed for trapping oil or gas, and an indication of promising regions for the occurrence of suitable structures is provided by the location of oil and gas fields in the United States (Figure 3-22). Structures suitable for aquifer compressed air storage are also found unassociated with petroleum reservoirs.

While the general nature and distribution of rock types provides a guide to the suitability of a region for compressed air storage, the specific conditions at the site selected will determine the economic and technical feasibility of a particular proposal. Systematic evaluation of the pertinent geological characteristics required to determine feasibility. Such an evaluation is described in Appendix C, "Procedures for Determining Site Suitability."

NATURAL CAVERNS

Many natural caverns are known within the United States, principally in sedimentary formations. The possibility that some of these might be adequate for a compressed air reservoir is regarded as remote, for the reasons discussed in the following paragraphs.

The formation of natural caverns largely results from water percolation or encroachment in areas that have been greatly delineated by either fault or fracture patterns. The water follows these crevices in the rocks and, in time,

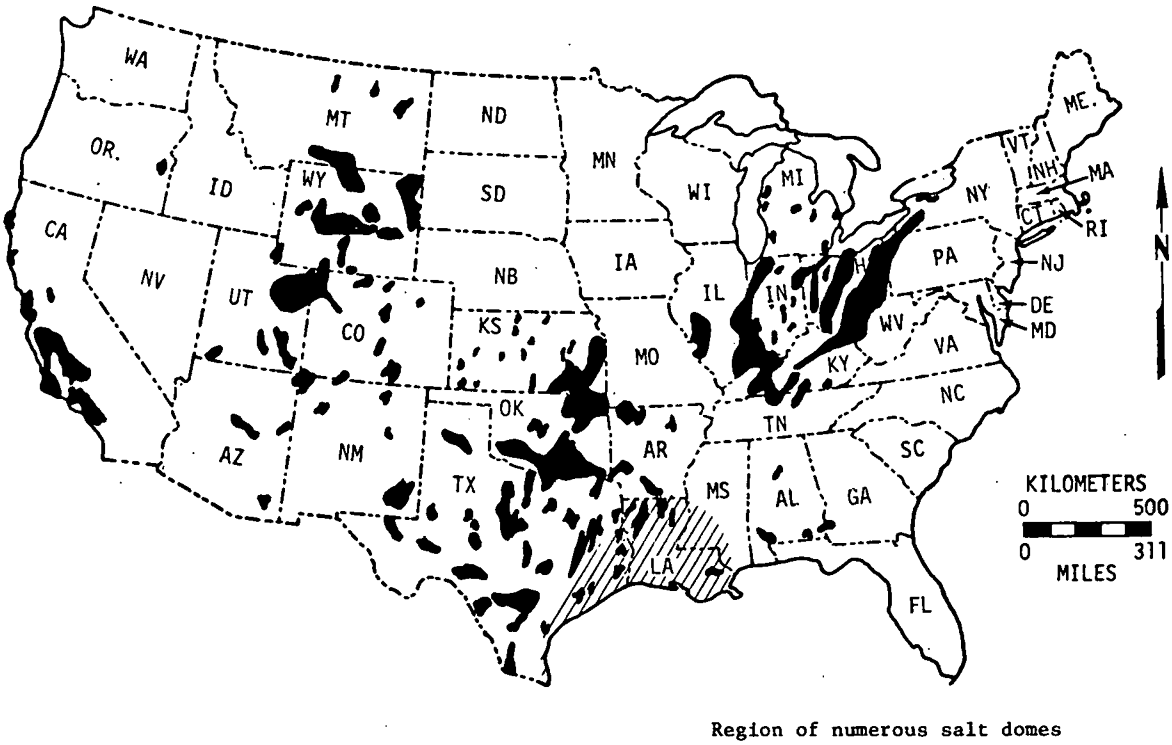

Figure 3-22. Major Oil and Gas Fields in the United States

dissolves channels in the host strata. For compressed air storage in such formations, the noted problems are that: 1) the joint fracture pattern generally is contiguous beyond the limits of the cavern, 2) depth is generally insufficient for such pressure (12 to 100 atmospheres) as would be required for CAES, and 3) migration of the compressed air in either or both directions of water flow is possible.

The majority of such natural caverns are too small to be considered as CAES sites. Known caverns that are of sufficient size are currently in use as tourist attractions. Some notable examples are:

- Carlsbad Caverns, New Mexico
- Marvel Cave, Missouri
- Fairy Cave, Missouri
- Fantastic Caverns, Missouri
- Meramec Caverns, Missouri
- Onandaga Cave, Missouri
- Mammoth Cave, Kentucky among others

Even if such large caverns were available for compressed air storage, their lateral extent is largely unknown and makes their use impractical without extensive, difficult, and costly surveying.

MINES

Numerous abandoned and operating underground mines are known to exist in the United States that could be considered for use as compressed air storage facilities. This underground space, occurring in a variety of geological environments, is randomly scattered throughout the country.

The concept of using available underground space for storage is not new, and many of the more suitable properties have already been acquired for this purpose. The recent oil embargo has focused new emphasis on storage of petroleum products, thereby creating additional demand for the remaining underground space. Increasing demand together with the specific site and structural requirements of a compressed air storage facility indicate that the availability of suitable existing "abandoned" or operating mines will be quite limited. Generally it appears that underground mines for low-unit-cost materials such as limestone or salt are most likely to be found adaptable for compressed air storage (Ref. 1).

Abandoned Mines

Available literature indicates that considerable manmade underground space currently exists within the United States, occurring as abandoned metal and nonmetal mines (Ref. 30). Most underground mines have been developed primarily for the extraction of natural resources at the lowest possible cost. The support pillars were designed for maximum safe resource extraction for the active mining period only. The mines are frequently allowed to cave when mining operations end (Refs. 7 and 22). Deposits that have been mined with high extraction ratios usually will be structurally unsound for use as compressed air storage chambers (Ref. 25).

The Tri-State District of Oklahoma, Kansas, and Missouri is an example of an area where mining with high extraction ratios has been completed. The mines are caving, some to the surface. Such mines will not provide adequate facilities for compressed air storage, since space is lost in the collapse and communication from the cavities with the surface is commonplace.

Most underground mines intersect some water during their time of operation and, when abandoned, are normally allowed to fill with water. This water would seriously restrict or prohibit any examination and evaluation of a given property. The dewatering of any large mine prior to an examination and evaluation to determine its potential for compressed air storage will generally be time-consuming and expensive.

In many instances, the chemical characteristics of the mine water is such that preliminary treatment is required, to meet environmental water standards, prior to surface drainage discharge. In the case of turbid mine waters, settling ponds may also be required prior to final discharge; this would considerably increase evaluation costs. In certain areas of the Coeur D'Alene district of Idaho, flooding of mines has been allowed through "abandonment" because of noneconomic production. In some areas, such as the Tombstone gold district of Arizona, flooding was one of the prime causes of closure of the mines. In nearly all cases of mine flooding, any proposed dewatering and reactivation of the mines is an expensive and not always successful venture.

When considering the use of existing underground space for a compressed air storage cavern, the overall economics of the property must be determined. This leads us to the question "When is a mine truly abandoned?". An upward price change for the mined product can greatly influence the overall economic condition of a given mining program, changing a submarginal or "abandoned" mine unit into an economically viable operation. Many mines have been closed down and allowed to flood, only to be dewatered and put back in production years later because of the increasing price and demand for the mined product. Under conditions such as these, the fair market value of the natural resource remaining in the mine would have to be weighed with reference to the potential value as a compressed air storage cavern.

Any evaluation of existing underground space to be used for compressed air storage will entail a detailed examination of the individual mine and mine site, both on the surface and underground. Geologic conditions can and do vary considerably from one mine to another within a given mining district, and therefore, require that any proposed site be evaluated strictly on a site specificity basis.

Operating Mines

The initial evaluation of an operating mine as an air storage cavern must include the compatibility of the different use concepts for the available space. Most underground mines that would possess the necessary volume requirements for the compressed air facility have been developed on ore deposits with considerable ore reserve tonnage. The overall economics of a given mine, considering the initial capital investment required, are dependent upon the extraction of the total ore body. In circumstances such as these it would seem that the mine management would be reluctant to have the property considered for use as a compressed air storage facility.

Even if an operating mine with a management favorable toward the air storage concept should be found near a load center or transmission corridor, examination and evaluation would be necessary before the potential of the site could be known. A case in point is the Tyrone district of New Mexico (Ref. 4). Several underground mines, now closed, exist in the area that might be suitable for compressed air storage. However, with the current development of an open-pit operation in the immediate vicinity of these mines, it seems unlikely that such storage would now be well received.

Summary

Most existing manmade underground space was designed and constructed for a specific purpose, with no thought given to possible future use as a compressed air storage facility. It is unlikely that the utility siting requirements and the mechanical integrity required for compressed air storage will be provided by existing mines.

A compressed air storage facility, designed for peak-load leveling of electric power demand, should be located in proximity to the load center. This siting requirement seriously restricts any opportunity to be selective in the search for an existing, most favorable underground environment. The nature of many mining operations and their consequent location away from population centers of the United States will make it a difficult task to locate suitable existing underground space within the load-center siting parameters.

As with natural caverns, most mines will have some fault-fracture patterns that may communicate to higher levels of strata, thus rendering them unsuitable for compressed air storage because of air leaks. However, every site must be evaluated on its own merits. An example is provided by mines in the Coeur d'Alene district of Idaho. The Osburn fault, which has a length in excess of 100 miles, a width of at least one hundred feet, and a large displacement, can be successfully traced on the surface by exposure and surface features. This fault traverses many of the mines in the district, and by the nature of its structure (gouge material, barren and shattered quartzite, possible communication to the surface, weakness of ground structure along the fault area) would render such areas unfavorable for compressed air storage.

CONVENTIONALLY MINED CAVERNS

The preparation of a conventionally mined underground cavern suitable for compressed air storage will require detailed, site-specific studies of the physical, chemical, and structural characteristics of the host formation. These studies will determine cavern configuration and mining method that will be most compatible, technically and economically, with the storage concept.

The physical characteristics of the host formation, including the overlying and underlying strata, will determine the overall integrity of the cavern. These studies will indicate which design is appropriate, and the back, rib, and floor conditions, drift widths, spalling conditions, porosity and permeability, water inflow, and air leakage that can be expected on the specific site. The chemical properties of the host formation may identify possible contaminant carryover from the cavern to the turbomachinery. These data must be obtained early in the program, to maintain an orderly plan for cavern development.

The comparative suitability of rock types for conventionally mined compressed air storage caverns is qualitatively summarized in Table 3-5. The hard rock lithologies having the greatest potential for compressed air storage were selected on the basis of widespread occurrences plus salient physical and structural characteristics. They can be broadly classed as granite and granite-like crystalling rocks of igneous or metamorphic origin. Perhaps the most important occurrences of hard rock believed suitable for air storage caverns extended along the easter seabosrd, roughly paralleling the Atlantic coast (Figure 3-17) (Ref. 31). For the most part, these exposures are medium to high grade metamorphic rocks such as gneisses and schists. North of Virginia, there are several large intrusive bodies, including dikes, sills, and stocks, composed of granite and associated igneous lithologies. At selected sites within this region, both the metamorphic and igneous rock units have been successfully utilized for underground low-pressure gas storage. The igneous and metamorphic lithologies should offer excellent potential for compressed air storage caverns at properly selected sites. These rock units represent some of the best environments for mining stable, relatively impervious caverns (Ref. 3).

Even in the case of hard-rock lithologies the field work during feasibility testing occasionally identifies unsuspected problems. A case in point was a potential cavern site on the eastern seaboard of the United States (Ref. 8). A granite porphyry was encountered in the first test hole, at a site indicating an area suitable for storage; but the second drill hole intersected a gneissic phorphyry, indicating that a structural feature lays between the two holes. This was found to be a fault, and the site was deemed unsuitable for storage. Further drilling did locate a suitable area.

Experience in building hard-rock caverns for LPG storage has shown that relatively large-volume caverns (up to 207,778 yd^3) of room and pillar design can be constructed that will provide secure containment of the stored product. Small water leakages into the cavern during construction, as a result of fissure permeability, are typical of relatively shallow (<500 ft) hard-rock environments. Excessive water inflows, which sometimes occur, are routinely grouted off to reduce the flow rates to acceptable levels. A totally dry cavern is is not usually required, since small water inflows can be collected in a sump and periodically pumped out. Storage caverns for hydrocarbon products are sited and designed to utilize a high static water pressure. Because this water pressure always exceeds the storage pressure of the product, the fissures responsible for permeability of the host formation are filled with water, preventing escape of the stored hydrocarbon.

The size of caverns mined for storage of hydrocarbon products is usually limited more by practical or economic considerations than by technical questions. Theoretically, caverns can be sized as large as desired, provided the rock characteristics are uniform and suitable throughout the proposed mining interval. It is anticipated that many of the same criteria governing hydrocarbon storage caverns will apply equally to compressed air storage caverns, particularly in hard-rock environments (Ref. 13).

Cavern Design

The most practical mining schemes for underground (hard-rock) storage caverns have used simple room and pillar configurations (Ref. 29). The room and pillar design allows relatively rapid excavation, a high extraction ratio, and excellent stability of the completed cavern. Figure 3-23 illustrates several common room and pillar configurations. The choice of design is usually based on such pertinent factors as formation characteristics (strength, structure, etc.), haulage and production efficiency, and percent of extraction desired.

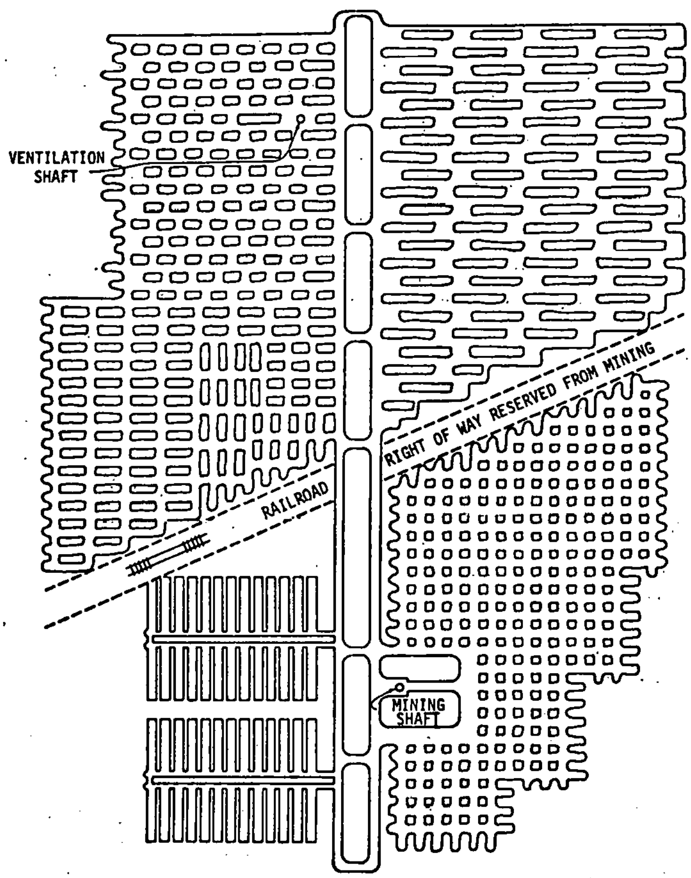

Figure 3-23. Room and Pillar Mine Configurations

Caverns constructed for a water compensated pressure system of compressed air storage might require certain modifications of the basic room and pillar design, to reduce the potential for turbulent flow during the water flood cycle. Although the water influx would be largely quiescent, any turbulence caused by water flowing around the pillars would, with time, result in mechanical degradation of the pillars. Principles of fluid dynamics should therefore be applied when determining the optimum pillar design for a given water-leg manifold system. For example, in the designs considered later in this report the water velocity was limited to 10 to 20 ft/sec, on the basis of the experience of the U.S. Bureau of Reclamation (Ref. 19). The rock mechanics of the design of caverns for compressed air storage is described in Appendix D, "Rock Mechanics Design."

There is strong evidence to indicate that bored caverns, as opposed to conventional blast and muck mining methods, would offer substantial benefits for air storage caverns. Primarily, these advantages pertain to reduced permeability due to less disturbance of the surrounding rock, better flow characteristics (compensated caverns), and increased stability as a result of less rock disturbance and the circular configuration of the openings (Refs. 24, 26, and 29).

The disadvantages in the use of boring machines are both economic and logistic in nature. The cost of building or leasing a boring machine (or machines) capable of developing a large-volume cavern would be high, compared with conventional mining costs. The time and expense of disassembling and reassembling a boring machine to get it underground would also be great. Finally, the state of the art is young, and currently available boring machines are probably not well suited to the requirements of developing air storage caverns; new machines suited to that type of mining would have to be developed, at a greatly increased cost. The approach taken for this study does not include a cost/benefit analysis of boring versus conventional mining; such a study could prove valuable at a later date, if compressed air storage in crystalline rocks should be indicated to have a major potential for utility application.

Conventional mining methods have proved to be quite satisfactory for construction of LPG storage caverns and should prove suitable for air storage caverns constructed in hard rock. The conventional mining method basically consists of drilling, blasting, and removing the rock along interconnected corridors. Normally the mining will progress stepwise from upper to lower benches until the proper height is reached. The broken rock is removed by hoist bucket through the mining shaft and disposed of on the surface.

The blasting operations are carefully controlled by spacing, load sizing, and sequential timing. Despite the controlled nature of the blasting operations, a certain amount of disturbance takes place in the rock adjacent to the shot face. This disturbance takes the form of new fractures and/or slippage, widening or extension of old fractures, joints, and faults. Under normal conditions the induced fracturing does not carry far from the blast point. Microscopic fractures may extend up to a few meters, while microscopic and detectable strain changes may occur several tens of meters away from the shot point. Subsequent stress/strain changes may last for days as the rock adjusts to the new load (stress) patterns produced by the mining activity.

One of the major problems to be anticipated in conventional mining of air storage caverns will be enhanced fracture permeability due to the blasting operations. Both water inflows during construction and air loss potential during operation can conceivably be increased by blast-simulated fracture permeability. The severity of these problems will depend on the underground conditions, mining methods used, and the mine configuration employed (Ref. 28). Leakage problems are discussed in more detail on the following pages.

Water Inflow

Water table drawdown as a result of cavern construction would not be expected to be a serious problem, provided the initial feasibility study indicated relatively tight and stable ground. Cavern construction should open only minor inflows, which probably can be controlled. Even if some influx of water into the cavern is sustained after remedial grouting has been done, it should not affect the surrounding water table beyond its capability of recharge.

Water influx into the cavern in the compensated storage system would, in most cases, merely add to the displacement water to be removed when the cavern is filled with air. If the water for pressurizing the cavern is taken from local aquifers, then drawdown would occur so long as water is being removed. Since this system calls for a lake on the surface to impound the displacement waters, the initial large drawdown would probably occur only once. Over a period of time, the aquifer should recharge itself from the surrounding areal aquifer, thus regenerating the needed cavern seal and replenishing the local aquifer. It is also possible that certain select aquifers (e.g., ground moraines and glacial till) would provide enough water for initial pumping so that no true drawdown cone would be realized; instead, a pressure drop of some ΔP would be noted and would rapidly rebuild, once pumping had ceased.

Once the initial lake filling has been achieved, only pumping to replace fluids lost by evaporation would be required. As stated previously, in a compensated hard-rock cavern the water inflow would be no real problem, since the pressure of the stored air would be such that the water would be held at minimal influx.

The possibility of air leakage does exist with either the compensated or the noncompensated cavern design. This possibility can be minimized by careful examination of a potential cavern site to ascertain that the stratum proposed for storage meets certain criteria for compressed air storage in that rock type. Some of the more important criteria are:

1. Adequate depth for hydrostatic pressure seal
2. Sufficiently high compressive strength in host formation to withstand mechanical cycling
3. Minimal permeability
4. No fracture communication to surface or other formations

If these criteria are met, then air containment should impose little difficulty. If leaks are encountered in an area where compressed air storage is desirable, there are methods that can be used to correct or minimize the situation.

Grouting. When potential leakage paths are encountered, a technique of grouting with neat cement is used to seal off these paths. Several factors are involved in a grouting operation: size and extent of fracture, water inflow head, and the degree to which rock is fractured. The degree of success that can be expected is dependent on these criteria, among others. If a fracture cannot be completely sealed because of high influx pressure, then the probability that such a fracture could cause cavern leakage is high. The possibility of this occurrence can be minimized in the initial feasibility research when strata conditions are determined.

Hydrostatic Control. A prime consideration for cavern operation is an adequate hydrostatic seal. This is ensured by a feasibility testing program to confirm the location of the prime water table; in cases where multiple aquifers are suspected, attempts are made to confirm these. For example, for a storage pressure of 12 atmospheres (177 psi) a minimum depth of 125 meters (410 feet) would be required. This assumes the aquifer overlying the cavern has its top near the surface and is contiguous across the cavern interval.

SOLUTION MINED CAVERNS

A method of cavern construction that is uniquely applicable to salt formations is that of washing a cavity in the salt by injecting fresh water into the formation, allowing it to dissolve salt to near saturation, and removing the brine from the cavity. Solution mined caverns are now extensively employed both in the United States and in Europe to store hydrocarbons (Ref. 6). The technology is well established, and when applicable to a site it is frequently the lowest-cost alternative for preparing a cavern.

The requirement that the brine resulting from mining be disposed of in an environmentally compatible fashion can be a major constraint on the application of this method. Another constraint is, of course, the availability of suitable salt at the site desired. Rock salt is not a homogeneous material, and careful analysis of the distribution of impurities such as anhydrite and potassium chloride is required before solution operations are begun. The distribution and characteristics of major salt deposits in the United States are described in Appendix B, "Salt Formations in the United States."

Thick domed salt such as that occurring along the Gulf Coast is particularly well suited to solution mining for cavern formation (Ref. 15). Domed salt tends to be purer (>95% NaCl vs. 90% NaCl) and more homogeneous than bedded salt. A cavern of a shape designed for this application is more easily constructed in domed salt than in the relatively thin salt beds.

A potential problem of cavern stability results from the susceptibility of salt to flow plasticity. Conventionally mined salt caverns, for example, will provide stable openings above 600 feet with a 70 percent extraction ratio, but at 1500 feet the extraction ratio must be less than 25 percent. Solution mined caverns can be developed for storage below 5000 feet, but closure problems resulting from heat and pressure will limit the operating life of deep caverns. Periodic cleanup (rewashing) of such caverns might be necessary to maintain a an adequate volume over several years' duration. Openings in salt will be less stable at higher temperatures. Sustained temperatures below 170 F probably will not induce rapid structural closure.

Fortunately, at depths corresponding to pressures up to 100 atmospheres the pressure and static temperature in a salt cavern are not likely to result in rapid closure. However, the possible effect on the rate of plastic flow of the relatively rapid cycling of temperature and pressure required by the CAES cycle is unknown.

AQUIFERS

An aquifer is a water-permeated formation of sand, gravel, soil, or porous stone. To prepare an aquifer for compressed air storage the water initially present must be displaced by air. This is done by drilling wells in the aquifer and slowly forcing compressed gas into the pore space. To be suitable for compressed air storage the aquifer must possess the following characteristics (Refs. 25, 26, and 27):

Permeability -- Rocks vary greatly in their resistance to the flow of fluids. The permeability of the aquifer rock must be great enough to allow air to be delivered to the wells at the mass flow rate needed by the turbine expander. The lower the permeability the larger the number of wells needed to achieve the necessary deliverability.

Porosity -- The fraction of void space per unit volume of rock is one determinant of the capacity of the formation to hold air. Residual water tightly held by capillary action in the pore space can significantly reduce the effective porosity of a rock below that measured in the laboratory. Such water is called connate water.

Cap Rock -- An impermeable layer of rock must overlie the aquifer to prevent stored air from migrating upward. The threshold pressure at which water is displaced from pores in a cap rock is a critical characteristic.

Closure -- The aquifer must be shaped to present a structural height that will prevent the stored air from migrating laterally or upward. Domes, anticlines, reefs, lenticular sands, and stratigraphic traps are all in use for natural gas storage and presumably would be suitable for air storage.

Depth -- The aquifer must be at sufficient depth to contain the required amount of air at an average pressure approximately equal to the pressure of water in the aquifer at the time of its discovery. The minimum pressure in the aquifer must be great enough to exceed the pressure required at the gas turbine inlet.

Extent -- The aquifer volume contained within the closure must be great enough to contain the required amount of air.

Considerable interest has recently been shown in natural gas storage in "flat" aquifers, possessing little or no trapping structure. This method of storage, which apparently has been successful in the USSR, is being investigated for potential gas storage in the United States (Refs. 16 and 31). However, the information available from field experience with natural gas storage in partially confined aquifers is very limited. This is an area worthy of further investigation, since partially confined structures with suitable permeability and porosity are much more numerous than are the confined structures meeting the porosity requirement described above. It is probable that the site preparation and operating costs will be higher for partially confined aquifers than for confined structures, because of the need to provide control of the air bubble through a series of water injection wells. Thus, in the application of compressed air storage, the first sites developed will be confined. The technology of control of gas or air stored in unconfined aquifers should be developed to provide second or third generation air storage in aquifers.

The predominant lithologies for development of good subsurface reservoirs (water or petroleum) are sandstone and fractured or vuggy limestone and dolomite. The greatest natural porosity and permeability values are almost always found in vuggy limestones and dolomites. These natural aquifers often are ancient reef structures, which have subsequently been covered with younger sedimentary deposits. Where the overlying strata drape over a reef structure, an effective anticlinal trap may develop and it is this type of structure which appears to offer the greatest potential natural storage space for compressed air. A similar structural condition is known to result where originally gently sloping strata have been arched upward, as a result of upheaval from below or compressive folding. Both fractured and/or vuggy calcareous strata and sandstone deposits are subject to this type of deformation, and many of the notable oil and gas discoveries are associated with such stratigraphic traps. Figure 3-24 illustrates the requisite structural conditions for trapped aquifer air storage.

Sandstone strata having high porosity and permeability values are commonly encountered within the large depositional basins (Figure 3-19). The degree of cementation is one of the primary factors controlling porosity and permeability of sandstone. The greater the cementation, the lower the pore space and fluid transmissibility of sandstone. Grain size and the quantity of silty material will also influence the hydraulic characteristics of sandy formation The larger the grains, the greater the intergrain void space; hence, pore volum and fluid transmissibility are increased. Silt and similar fines are normally deposited along with sandy sediment, and if they are sufficiently concentrated they effectively reduce both porosity and permeability. Therefore, a clean sand or sandstone formation is to be preferred when considering fluid displacement traits.

The development of an aquifer for air storage will require a rather extensive drilling and exploration program. Preliminary data indicating a suitable structure for entrapment will usually be obtained by making geophysical surveys across geologically promising areas. By analysis of regional and local geology, hydrology, geophysical surveys, and available drilling records, an exploratory drilling program can be developed to better define the subsurface conditions relevant to air storage.

The number, locations, and depths of exploratory drill holes will be determined by the local conditions and will vary from site to site. The essential information for air storage will include the following:

1. Size and shape of the structural trap
2. Depth to the cap rock and aquifer (top and bottom contacts)
3. Porosity and permeability of the aquifer
4. Static water pressure of the storage aquifer, plus determination of water level(s) of overlying aquifers (a difference between aquifer head pressures is useful for determining interformational communication between aquifers)
5. Hydrologic conditions such as saturation and wager composition
6. Reservoir rock homogeneity (vertical and horizontal consistency)
7. Hydrodynamic potential differences across a reservoir
8. Cap rock permeability (core analysis and in situ testing)

Many of the existing gas storage reservoirs are located in depleted oil and gas fields, where structural and rock conditions have already proved right for holding hydrocarbon fluids (Figure 3-25). The possibility of utilizing water aquifers above (or possibly below) a producing or depleted hydrocarbon reservoir would probably be acceptable where suitable conditions exist. However, the testing to confirm isolation from any nearby reservoirs would necessarily be more extensive. Since the reservoir forming structures are often quite large, encompassing hundreds of meters of strata over many square kilometers of area, the possibility of finding hydrocarbon-free reservoirs within a known oil and/or gas bearing structure is a distinct possibility. Oil company records and well logs will undoubtedly contain much pertinent information about water bearing formations in entrapment structures. Unfortunately, because of the competitive nature of the exploration business these data are not usually released from company files. Once the aquifer air storage concept is proven, many of these potential reserviours are expected to be made

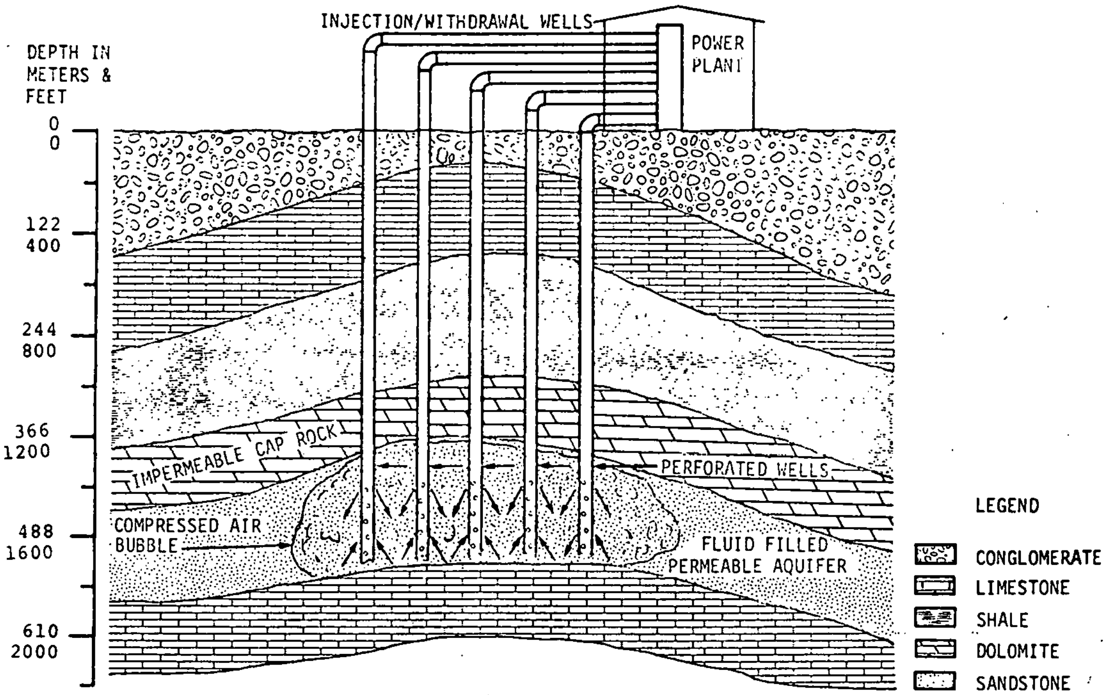

Figure 3-24. Typical Proposed Aquifer Air Storage Facility

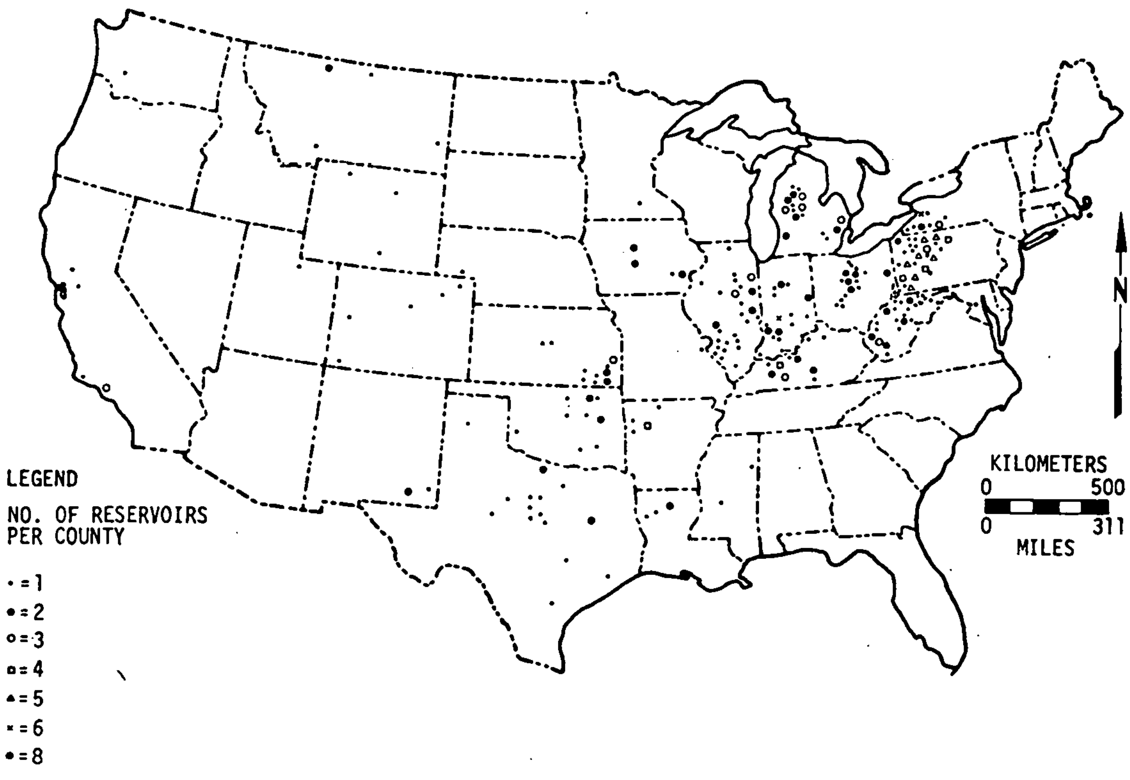

Figure 3-25. Natural Gas Subground Storage Reservoirs in the United States

known to interested electric utilities, probably at a price reflecting exploration and related costs to the developer.

DEPLETED OIL AND GAS FIELDS

As evidenced by their ability to trap hydrocarbons, depleted oil and gas reservoirs possess the structural features required for compressed air storage. Many fields are known, widely distributed throughout the United States (Figure 3-22), but the presence of residual hydrocarbons in the formation complicates their use for compressed air storage. The compressed air returning from storage may contain an explosive mixture of volatile hydrocarbons that would be detonated by the ignition of the combustor. Many of the old fields contain from 50 to 80 percent of the original hydrocarbon in the formation and must be regarded as a natural resource, dependent on the price and scarcity of petroleum and the development of more advanced recovery technology. Oxidation of residual hydrocarbons in the formation could lead to decreased permeability and to depleted oxygen in the air returned to the turbine.

The apparent availability of sites may be somewhat illusory. Complications for compressed air storage introduced by the presence of residual hydrocarbons do not apply to natural gas storage; hence one may conclude that the gas storage companies have acquired the sites near population centers in the northeast and north central states. The need to operate coal-based synthesis gas plants at nearly constant output suggests that the need for such gas storage facilities will not decrease in the future. Because inadequate records exist on many of the older oil and gas reservoirs and well abandonment procedures were often inadequate, it would be necessary to locate all old wells and to plug them before attempting to store air in the reservoirs. This would add significantly to the time and cost of developing the field.

Thus it appears that while many depleted oil and gas fields could prove to be physically suitable for compressed air storage, there are potential technical and institutional problems associated with the presence of residual hydrocarbons that may limit their use. A detailed examination of a suitable field is required, together with studies of the interaction of compressed air with the residual hydrocarbons in the formation.

SEISMIC RISK

In the coterminous United States, earthquakes and flexures have been recorded since the advent of explorers on the continent. Figure 3-26 shows generalized areas of varying damage intensity, on a scale of 0-3. Epicenters of major earth tremors are also shown .

Examining potential sites for energy storage facilities will require research into the specific areas to assess the seismic history and to attempt

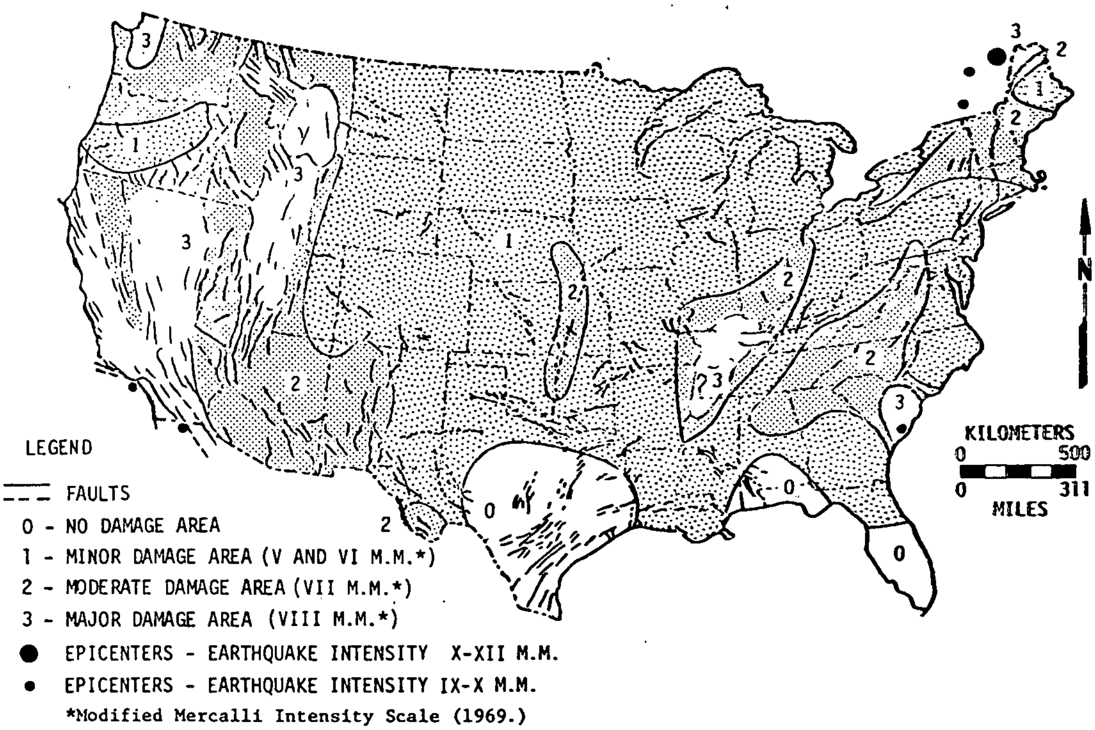

Figure 3-26. Seismic Risk Areas and Fault Zones

to determine the probability and possible intensity of future seismic events. Examination of geological data and field work to determine structure of a given area will assist in such assessments.

Experience in similar research on mine conversions has indicated that relatively large mine facilities located near a high-intensity seismic event exhibit little if any damage as a result of such a nonepicentral contact. It was noted that men working within the mine at the time of the event had little or no knowledge of its occurrence until informed by those on the surface. The quake was measured by instruments in the area as a force V (Richter) event (Ref. 27).

Damage to an underground facility located at depth probably would be negligible, with the major part confined to hydrostatic conditions surrounding the facility (i.e., rise or fall in static water level) or a fissuring of the area to create a potential loss zone. Careful geologic and seismic examination of potential sites will afford a minimization of such potential hazards.

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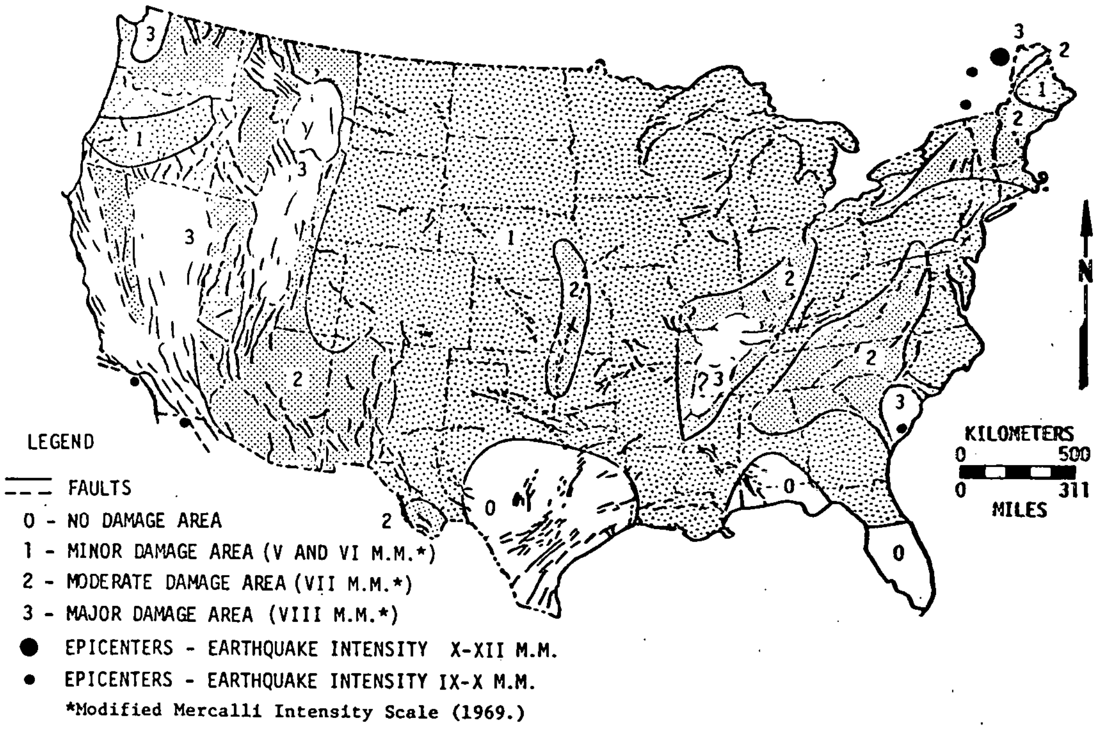

Figure 3-26. Seismic Risk Areas and Fault Zones

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Section 4

ECONOMIC AND OPERATING CHARACTERISTICS

4.1 INTRODUCTION

From the assessment of technical characteristics of the major systems of a compressed air storage plant, the conclusion has been reached that the basic compressed air cycle is technically feasible using currently available technology. The siting and operating of plants will be affected by many detailed considerations. Also, there are a number of questions about life and performance of particular embodiments that require experimental resolution. However, no new technology will be required to demonstrate the CAES cycle.

It is essential to the widespread implementation of compressed air storage not only that the technology be feasible and technically adaptable to the utilities requirements, but that it meet the economic criteria utilities employ in planning expansion of their generating plant. In this phase of the work, a basis for estimating the capital and operating costs of CAES systems was developed and employed to rank the relative economic feasibility of alternatives. This ranking provides a guide to the relative timing of implementation and is one element in determining priorities for any indicated research and development. In addition these costs, translated into electricity generation costs, can be used to assess the prospects for implementation of compressed air storage by utilities when primarily economic factors govern their selection among storage and generation alternatives.

4.2 DESIGN PARAMETERS

The basic characteristics of the cycles chosen for the economic assessment are described in Section 3-2. Plants incorporating both the first generation base system represented schematically in Figure 3-1 and the second generation high pressure recuperation/expander cycle represented in Figure 3-5 were considered. The turbomachinery systems performance for these plants is summarized in Table 3-2.

The range of maximum pressures for CAES plants included in the assessment is from 12 atm to 80 atm. The pressure ranges selected for this study are not determined by physical limitations. The lower pressure of 12 atm was chosen to provide a match with the inlet pressures of the combustor/turbine sections of currently available gas turbines. The upper pressure, 80 atm, is not a requirement set by equipment. However, the economics of compression becomes unfavorable at higher pressures, and it was thought that 80 atm would bracket the economically attractive pressure range. It had been reported for a compensated scheme that the total capital cost of the system turbomachinery plus cavern passed through a minimum near 40 atm (Ref. 2-60). Since operating costs increase at higher pressures, the generation costs should also pass through a minimum with pressure.

The size and duty cycle of the CAES plants assumed for the economic assessment was selected somewhat arbitrarily. The 150 MW increment corresponds to the output in the compressed air cycle of large industrial gas turbines produced currently. Two power ratings were selected to determine what sort of scaling relationships of cost with power existed. Since it has been generally claimed that a utility is justified in having 10 to 15 percent of its generating capacity provided by storage, 600 MW would correspond to the kind of plant needed by the twenty largest United States utilities. It was thought that four hour- and eight hour-cycles might correspond to peaking and midrange duty. However, the assessment of energy storage being carried out in parallel with this study has determined that these are both representative of peaking duty.

A storage temperature of 125 F was selected as being one at which minimal disturbance of the mechanical integrity of the reservoir should occur. It was assumed that the temperature at the end of charging corresponded to this design temperature. In the case of aquifer storage, this appears to provide an accurate description of the steady state operation of the aquifer because the porous formation will act as a regenerator and the resulting change of temperature with pressure will be less than 1 F for a two-fold pressure variation. In the case of the compensated cavern, the pressure will be sensibly constant during the charge and discharge cycle, and any temperature variation will result only from differences between the incoming air and the water temperatures. The case of the uncompensated cavern is more complex since there will be a temperature rise during charging and a fall during discharging of the cavern (Ref. 2). The extent of this temperature change depends on the cavern design and the heat transfer characteristics of the host formation. A preliminary analysis for a salt cavern suggests that a 60 to 70 F temperature rise during charging to 80 atm and a 40 to 50 F temperature rise during discharging might be expected. The effect of the temperature change would be to derate the storage capacity of the cavern by 10 to 15 percent. This has not been done in estimating the storage costs in this study, because of the uncertainty of the result. An analysis of this effect should be carried out for a specific design of an uncompensated cavern.

The effects of the overall pressure and of pressure losses on the variable cost of operating a CAES plant can be quantitatively summarized in the ratio of the energy generated per unit of air released from storage to the energy required to compress a unit of air placed in storage. The magnitude of this ratio for the CAES plants included in the economic assessment are designated in Table 4-1 as compression energy factors. The compression energy factor measures the effect of a number of loss mechanisms on the pumping energy requirements:

- Since in cycles without heat storage the heat of compression is discarded, the greater the heat production for unit of air stored, the greater the charging energy required by the compressors for a given quantity of energy generation by the CAES plant. This is the

Table 4-1

PERFORMANCE OF CHARACTERISTICS OF CAES SYSTEMS

Type of Storage	Pressure (atm)	Heat Rate (Btu/kWh)	Charging Energy Factor[b]
Compensated	12	5252	1.58
	40	5252	1.03
	40 EXP[a]	5015	1.36
	80	5252	0.90
	80 EXP[a]	5015	1.18
Uncompensated	20-12	5252	1.44
	40-20	5252	1.16
	80-40	5252	0.96
	80-40 EXP[a]	5015	1.26
Aquifer	12	5252	1.39
	40	5252	0.99
	40 EXP[a]	5015	1.30
	80	5252	0.89

a) Cycle with high pressure recuperator and expander.
b) Defined as ratio of the net energy generated to the energy required to charge the reservoir.

major reason that the charging energy factor becomes less favorable for each of the storage modes as the maximum pressure of storage is increased. For example, for 80 atm storage pressure, a CAES plant employing either aquifer or compensated cavern storage actually will generate less energy than is used to charge the reservoir, even though fuel is burned to heat the air coming from storage.

- Frictional losses from air flowing through the air shafts and air collection piping decreases the charging energy factor. The pressures indicated in Table 4-1 are nominal, and for each case static and flowing pressure gradients for the depth, pressure, and air shaft size were calculated to assure that the pressure losses were less than 1 atm. For example, for a fresh water compensated reservoir with a nominal pressure of 40 atm and a single 30-inch diameter air shaft, the actual bottom hole pressure of 40.2 atm requires that the compressor train provide 38.5 atm to the wellhead during charging and yields 38.1 atm at the wellhead during the discharge. In general, the nominal pressures in the cases of compensated caverns and aquifers correspond to the shut-in bottom hole pressures. In the uncompensated cases, the pressures correspond to the flowing wellhead pressures at the beginning and end of discharge. Air shafts were sized for the uncompensated caverns for the pressure drop at the end of discharge.

- For aquifer storage, frictional losses due to air flow through the porous rock decrease the charging energy factor. The permeability of the rock at a particular site will generally not be subject to the control of the designer, and thus is not a variable parameter. For the methods used to estimate the flow losses, Appendix E, "Economics of Storage Development," should be consulted.

There are tradeoffs possible between the variable cost of charging energy and the fixed cost of a CAES plant. Thus by increasing the number of air shafts and enlarging the diameter of the air collection piping, air flow losses and investment in compressors can be reduced. In the case of an aquifer storage field, flow losses in the reservoir rock can be decreased by spacing wells more closely together as well as by enhancing the permeability of the formation through fracturing. Storage in caverns at lower pressures requires that a larger cavern be constructed to store a given mass of air, thus increasing the capital cost of the plant. Only a preliminary examination of these tradeoffs was undertaken in this study. The results indicated that while this optimization must be undertaken in designing a plant to meet a specific set of utility requirements and site constraints, failure to optimize each case will not invalidate the conclusions concerning economic choices among alternatives.

4.3 ELEMENTS OF THE OPERATING COST

The principle elements of the total operating cost for a CAES plant are the cost of premium fuel for the combustion turbine, and the cost of electricity to compress air for storage. The variable operating and maintenance costs are expected to be relatively much smaller. For this study, the variable operating and maintenance cost is estimated to be 2.0 mills/kWh, based on experience with industrial gas turbines.

As the analysis presented in this section reveals, the economic choice between CAES and other alternatives available to a utility is quite sensitive to the cost to the utility of petroleum derived fuel. While low cost natural gas is widely used at present to fuel gas turbines, it is assumed for this study that if natural gas or synthetic gas from coal is available to utilities in the period 1980 to 2000, it will be at an equal or higher cost than that of liquid fuels. A number of projections for petroleum fuel costs are available, but the uncertainty in each seems rather great. Some of these are contained in Table 4-2.

Table 4-2

ESTIMATED COSTS OF COMBUSTION TURBINE FUEL

Item	$/MBtu	
	1980	1990
"Maximum" escalation[a]	3.22	8.36
Reference 3	2.57	4.56
Reference 4	3.26	3.78
Reference 5	3.35	6.00
Synthetic liquid fuel[a]	--	11.98

a) See text for explanation.

Under present regulatory practice, the Federal Energy Agency is required to maintain the annual escalation in petroleum costs within the United States at less than 10 percent. For utilities able to obtain turbine fuel at $2.00/MBtu in 1975, this would place an upper limit of $3.22/MBtu for this fuel in 1980. Since the FEA responsibility is concerned with the price of crude petroleum rather than refined products, there is no assurance that the 10 percent maximum annual escalation will apply to turbine fuel. A possible upper limit on turbine fuel cost in 1990 may be placed by taking into account the potential availability of synthetic liquid fuel from coal at a cost of roughly $5.00/MBtu in 1975 dollars. If an average annual inflation rate of 6 percent prevails over the period, then a cost of $11.98/MBtu for a liquid synthetic fuel in 1990 will result. For the present study, it appears that a cost of $3.25/MBtu in 1980 is appropriate, with annual escalation of 6 percent.

A second major element of the cost of operation of a CAES plant is the cost which a utility charges itself for the energy used to compress the air placed in storage. This cost is a variable from utility to utility, depending on the generation mix and fuel costs as well as on the shape of the load curve. It is not possible to provide a single energy cost that can be generally applied. In this study, two average charging power costs were assumed: $10/MWh and $20/MWh (Ref. 5).

4.4 INVESTMENT IN TURBOMACHINERY AND BALANCE OF PLANT

Cost estimates for complete turbomachinery systems have been made for the base system, and for the second generation high pressure recuperator with expansion turbine system. These cost estimates are summarized in Table 4-3. For either the base system or the high pressure recuperator/

Table 4-3

TURBOMACHINERY AND BALANCE OF PLANT COST ESTIMATES IN 1975 DOLLARS

Configuration	Base[a] Equipment ($/kW)	Booster[b] Compressors ($/kW)	Balance of Plant ($/kW)	Total Cost ($/kW)
Base system, atm				
12	72.8	6.7	31.3	110.8
40	72.8	31.0	47.5	151.3
80	72.8	46.0	57.5	176.3
High pressure expander/recuperator system, atm				
40	87.3	23.6	47.5	158.4
80	87.3	35.0	57.5	179.8
Simple cycle gas turbine plant	80.0	--	30.0	110.0
Recuperative cycle gas turbine plant	131.0	--	40.0	171.0

a) Axial compressor, turbines, combustion system, recuperators, motor generators, couplings and auxiliaries.
b) Centrifugal compressors, motors, gears, couplings and auxiliaries.

expander system, the total machinery cost is dependent on the overall system pressure level - the higher the storage pressure, the greater the amount and cost of the compression equipment. Therefore, the equipment costs have been divided into those of the base equipment, i.e., the minimum amount of equipment that would be in each system regardless of pressure level, and those of the booster compressor equipment necessary to achieve a desired pressure level.

The base equipment corresponds to the General Electric MS-7001 components, axial compressor, turbine combustion system recuperator, motor-generator couplings and auxiliaries such as starting motor lube system controls. The cost of this equipment is estimated to be approximately $73/kW which is somewhat more than half the cost of a conventional regenerative gas turbine which has a similar set of components. Note that "cost" refers to market selling price, not manufacturers cost. The output of the regenerative cycle gas turbine is 65 MW or 44 percent of the CAES system output. Thus, without any additional equipment or cost, the CAES system base equipment minimum cost would be 44 percent of $131/kW or $58/kW. However, the CAES system includes two couplings, a much larger generator, separate compressor and turbine base plates, and a separate lube oil system that result in the estimated price of $73/kW.

The booster compressors, electric motor drives, gearboxes, couplings and auxiliaries add from $7/kW to $46/kW depending on the pressure ratio resulting in total turbomachinery equipment cost estimates ranging from approximately $73/kW to $113/kW.

Based on preliminary estimates made with a limited amount of technical definition of the components, the addition of the expansion turbine and replacing the conventional recuperator with the high pressure recuperator raised the base equipment cost to approximately $81/kW. However, the booster compressor equipment is identical to the base system, and hence its cost is reduced proportionately to the increase in output from the expansion turbine. This cost reduction almost completely offset the higher base equipment cost resulting in total turbomachinery costs for the second generation system approximately equal to the first generation base system cost.

The cost estimate for the balance of plant is based on presently erected turbine plant designs proven in practice for their reliable operation and personnel safety. The estimated costs presented are based on July 1975 dollars, but do not include interest or escalation during construction. The estimates include the cost of the transformer and switchyard and the cost of installation of the turbomachinery. All estimates assume that the compressed air plant is self-sufficient. Therefore, sanitary facilities for the operating staff, spare parts storage, and transportation facilities are included. The cost estimate does not reflect possible additional costs related to specific site-related requirements such as soil stabilization and extensive site levelling. Roads, railroads, and city water sources are assumed to be within the plant boundary. Air piping costs assume a separate cavern and plant site, sharing a common boundary.

Quantitative data for an airborne particulate removal system does not exist. Such a system may be necessary for reliable operation of the compressed air plant; however, cost of this system is not included.

4.5 INVESTMENT IN UNDERGROUND STORAGE

The costs of the turbomachinery and of the balance of plant components can generally be based on experience with standard manufactured equipment. However, the range of uncertainty in the costs of the underground storage needed in a CAES system is much greater because the cavern design or aquifer development plan must be based on the conditions prevailing at the specific site of the plant. The costs of construction at that site can be profoundly affected not only by the geological characteristics of the host formation, but by such regional variables as labor costs, land values, and the cost of disposal of waste rock or brine. In carrying out the economic assessment, a set of assumptions was made drawn from experience in the construction of conventional and solution mined caverns for hydrocarbon or gas storage, and from the experience of natural gas storage in aquifers. The costs derived on this basis represent a bench mark against which the costs pertinent to a particular site can be measured. To permit the interested reader to interpret and adapt these cost assumptions to the conditions prevailing in the locality of interest to him, the cost elements are presented in the tables in Appendix E, which should be consulted for details.

Some cost characteristics of compensated and uncompensated storage in conventional and solution mined caverns at various pressures are compiled in Table 4-4. The average cost of storage is obtained by dividing the total cost of storage for 600 MW, 8 hour by 4800 MWh. The incremental cost of storage is obtained by dividing the cost increment between the 4 hour and 8 hour, 600 MW plants by 2400 MWh. The notation "EXP" after a pressure denotes the cycle in which an expander turbine is employed. The effect of the expander is to increase the effective capacity of a given storage cavern because more energy is extracted from the stored air during expansion through the expander, by a factor of 31 percent.

Table 4-4

COST CHARACTERISTICS OF ALTERNATIVES FOR STORAGE

Storage	Pressure (atm)	Average Storage Cost 8 Hr 600 MW ($/kWh)	Incremental Storage Cost 600 MW ($/kWh)
Uncompensated			
-Conventional	20-12	38.20	41.90
	40-20	18.00	11.70
	80-40	13.50	14.10
	80-40 EXP	10.30	10.80
-Solution	20-12	6.70	6.00
	40-20	6.30	4.00
	80-40	5.90	2.70
	80-40 EXP	4.50	2.00
Compensated			
-Conventional	12	29.40	25.30
	40	13.20	8.00
	40 EXP	10.00	6.10
	80	10.40	10.00
-Solution	12	14.10	10.70
	40	7.40	2.60
	40 EXP	5.60	2.00
	80	4.30	1.30
Aquifer	12	10.10	0.50
	40	7.80	0.31
	40 EXP	5.90	0.24
	80	8.70	0.36

Previous preliminary evaluations of the economics of compressed air storage have often started from some assumed cost of storage in $/kWh (Refs. 2-23, 2-45). As can be seen from Table 4-2, such a generalized approach to estimating storage economics is not justified. On an average cost basis, solution mined, uncompensated caverns afford the lowest storage costs, and conventionally mined, uncompensated caverns, the highest costs. The incremental cost of storage is lowest for aquifers, indicating that once a desired power rating is established for an aquifer field, its storage capacity may be increased at a rather low cost as required by the utility's needs. Both the average and incremental cost of storage becomes small at increasing pressures and depths. Aquifer storage is an exception. There appears to be a shallow minimum in storage costs in aquifers as a function of depth.

4.6 ECONOMIC COMPARISON OF ALTERNATIVES

A common method for comparing alternative methods for generation expansion is the use of screening curves, or what is usually equivalent, generation costs of electricity. Since the use of the screening curve technique with energy storage methods is not straightforward, the basic method used in this section is to calculate the generation costs of energy for the systems whose capital costs and performance characteristics have been estimated in previous sections of this report. Generation costs in 1975 and 1981 are estimated employing the general economic assumptions summarized in Table 4-5. Because of the wide divergence of projected costs for combustion turbine fuels beyond about 1980 (Table 4-2), the comparison of alternatives at a much later time, say 1990, is not made. However, using the methods and investment costs summarized in this report, the reader may apply his own assumptions to assess the economics of CAES alternatives beyond 1981. The year 1981 was selected as a comparison year because it is judged to be the first year in which it might be conceptually possible to begin operation of a CAES plant.

Table 4-5

GENERAL ECONOMIC ASSUMPTIONS

Carrying charges (Ref. 5)	
CAES plants	15.66%
Simple cycle turbine plants	14.04%
1975 cost of charging power	
$10/MWh	
$20/MWh	
1981 cost of charging power	
$10/MWh	
$20/MWh	
Interest during construction	10%
Annual escalation of capital costs	6%
Cost of distillate fuel	
1975 $2.00/MBtu	
1981 $3.44/MBtu	

The basis for comparison of the costs for compressed air plants was taken to be the simple cycle gas turbine. This alternative is one the utilities have selected for peaking duty, and provided that suitable fuel is available, it would be the one against which utilities would measure the economic performance of the CAES system. The life, reliability, and other operating characteristics of a simple cycle gas turbine are well known, and comparison of those expected of a CAES system has already been made in Subsection 2-7 of this report.

Estimated generation costs and cost elements for a 600 MW plant operating in 1975 are summarized in Tables 4-6 through 4-9. These costs have been derived as follows:

- The investment cost element is obtained by summing the appropriate turbomachinery and balance of plant costs from Table 4-3 with the storage costs from Table 4-4. This quantity, when multiplied by the fixed charge rate from Table 4-5, and divided by the plant generation rating (600,000 kW) and the number of hours of operation per year results in the quantity in the column headed investment cost element. It represents the portion of the generation cost due to the expenses of ownership of the plant. The quantities in Tables 4-6 and 4-7 are calculated for 200 days/yr of generation, with a daily generation time of four hours. Tables 4-8 and 4-9 are based on 8 hours of generation daily.
- The fuel cost element is obtained from the appropriate heat rate from Table 4-1 and an assumed 1975 fuel cost of $2.00/MBtu.
- The compression energy cost is obtained by multiplying together the appropriate compression energy factor from Table 4-1, the plant rating (600,000 kW), the number of hours of operation each year (either 800 or 1600) and the assumed cost to the utility of electricity to operate the compressors of the CAES plant. The values in Tables 4-6 and 4-8 are based on an average cost of $10/MWh and those in Tables 4-7 and 4-9 on $20/MWh.
- The variable operating and maintenance cost is assumed to be $2.0/MWh based on experience with industrial gas turbines.

The total generation cost is obtained by summing the individual cost elements. An examination of the total costs in the tables reveals that, based on these assumptions, none of the CAES alternatives is economically favorable compared to a simple cycle gas turbine installation in 1975. By examining the cost elements, it can be seen that the 12.1 mills/kWh fuel cost advantage of the CAES systems is more than offset by the sum of the compression energy and incremental capital costs. For example, for 8 hour daily operation, the total investment and compression energy costs of a CAES system must be less than 21.7 mills/kWh to achieve an economic advantage over the simple cycle turbine plant. The low pressure CAES plants employing storage in solution caverns or aquifers are sufficiently close to the 21.7 mills/kWh

Table 4-6

1975 GENERATION COSTS FOR 600 MW PLANT OPERATED 4 HRS/DAY WITH A COMPRESSION ENERGY COST OF $10/MWh

Configuration	Total Generation Cost (mills/kWh)	Cost Elements (mills/kWh)			
		Capital Charges	Fuel	Compression Energy	Operating and Maintenance
Simple cycle gas turbine plant	43.8	19.2	22.6	--	2.0
CAES: Conventional cavern, compensated, atm					
12	70.2	51.5	10.5	6.2	2.0
40	66.8	44.6	10.5	9.6	2.0
80	67.4	43.8	10.5	11.1	2.0
CAES: Conventional cavern, uncompensated, atm					
20-12	75.3	55.9	10.5	6.9	2.0
40-20	70.7	49.5	10.5	8.6	2.0
80-40	70.1	47.3	10.5	10.4	2.0
80-12	66.2	43.3	10.5	10.4	2.0
CAES: Solution cavern, compensated, atm					
12	54.1	35.4	10.5	6.3	2.0
40	61.5	39.4	10.5	9.6	2.0
80	63.9	40.2	10.5	11.1	2.0
CAES: Solution cavern, uncompensated, atm					
20-12	53.4	34.0	10.5	6.9	2.0
40-20	58.4	37.3	10.5	8.6	2.0
80-40	64.6	41.6	10.5	10.4	2.0
CAES: Aquifer storage, atm					
12	58.5	38.9	10.5	7.1	2.0
40	64.6	42.0	10.5	10.1	2.0
80	71.6	48.0	10.5	11.1	2.0

Table 4-7

1975 GENERATION COSTS FOR 600 MW PLANT OPERATED 4 HRS/DAY WITH A COMPRESSION ENERGY COST OF $20/MWh

Configuration	Total Generation Cost (mills/kWh)	Cost Elements (mills/kWh)			
		Investment	Fuel	Compression Energy	Operating and Maintenance
Simple cycle gas turbine plant	43.8	19.2	22.6	--	2.0
CAES: Conventional cavern, compensated, atm					
12	76.5	51.5	10.5	10.0	2.0
40	76.4	35.7	10.5	15.4	2.0
80	78.5	35.0	10.5	17.8	2.0
CAES: Conventional cavern, uncompensated, atm					
20-12	82.1	44.7	10.5	11.1	2.0
40-20	79.3	39.6	10.5	13.8	2.0
80-40	80.5	37.8	10.5	16.6	2.0
80-12	76.6	34.6	10.5	16.6	2.0
CAES: Solution cavern, compensated, atm					
12	60.4	27.2	10.5	10.0	2.0
40	71.1	29.8	10.5	15.4	2.0
80	75.0	33.3	10.5	17.8	2.0
CAES: Solution cavern, uncompensated, atm					
20-12	60.2	27.2	10.5	11.1	2.0
40-20	67.0	29.8	10.5	13.8	2.0
80-40	74.9	33.3	10.5	16.6	2.0
CAES: Aquifer storage, atm					
12	73.0	31.1	10.5	11.4	2.0
40	74.6	33.6	10.5	16.2	2.0
80	82.8	38.4	10.5	17.8	2.0

Table 4-8

1975 GENERATION COSTS FOR 600 MW PLANT OPERATED 8 HRS/DAY WITH A COMPRESSION ENERGY COST OF $10/MWh

Configuration	Total Generation Cost (mills/kWh)	Cost Elements (mills/kWh)			
		Investment	Fuel	Compression Energy	Operating and Maintenance
Simple cycle gas turbine plant	34.2	9.6	22.6	--	2.0
CAES: Conventional cavern, compensated, atm					
12	52.8	34.0	10.5	6.3	2.0
40	47.4	25.2	10.5	9.7	2.0
80	49.1	25.4	10.5	11.1	2.0
CAES: Conventional cavern, uncompensated, atm					
20-12	60.1	42.6	10.5	6.9	2.0
40-20	50.1	29.0	10.5	8.6	2.0
80-40	50.8	27.9	10.5	10.4	2.0
80-12	47.4	24.5	10.5	10.4	2.0
CAES: Solution cavern, compensated, atm					
12	40.8	22.0	10.5	6.3	2.0
40	42.9	20.7	10.5	9.7	2.0
80	44.2	20.6	10.5	11.1	2.0
CAES: Solution cavern, uncompensated, atm					
20-12	37.4	17.9	10.5	6.9	2.0
40-20	41.3	20.2	10.5	8.6	2.0
80-40	44.8	21.9	10.5	10.4	2.0
CAES: Aquifer storage, atm					
12	39.8	20.0	10.5	7.2	2.0
40	43.8	21.2	10.5	10.1	2.0
80	47.8	24.1	10.5	11.2	2.0

Table 4-9

1975 GENERATION COSTS FOR 600 MW PLANT OPERATED 8 HRS/DAY
WITH A COMPRESSION ENERGY COST OF $20/MWh

Configuration	Total Generation Cost (mills/kWh)	Cost Elements (mills/kWh)			
		Investment	Fuel	Compression Energy	Operating and Maintenance
Simple cycle gas turbine plant	34.2	9.6	22.6	--	2.0
CAES: Conventional cavern, compensated, atm					
12	59.1	34.0	10.5	12.6	2.0
40	57.1	25.2	10.5	19.4	2.0
80	60.2	25.4	10.5	22.3	2.0
CAES: Conventional cavern, uncompensated, atm					
20-12	69.0	42.6	10.5	13.9	2.0
40-20	58.8	29.0	10.5	17.2	2.0
80-40	61.1	27.9	10.5	20.8	2.0
80-12	57.8	24.5	10.5	20.8	2.0
CAES: Solution cavern, compensated, atm					
12	47.1	22.0	10.5	12.6	2.0
40	52.6	20.7	10.5	19.4	2.0
80	55.4	20.6	10.5	22.3	2.0
CAES: Solution cavern, uncompensated, atm					
20-12	44.3	17.9	10.5	13.9	2.0
40-20	49.9	20.1	10.5	17.3	2.0
80-40	55.1	21.9	10.5	20.8	2.0
CAES: Aquifer storage, atm					
12	47.0	20.0	10.5	14.5	2.0
40	53.9	21.2	10.5	20.3	2.0
80	59.0	24.1	10.5	22.4	2.0

target, that changes in the cost of the compression energy available to a utility, for example, to $4/MWh, would change their economic ranking relative to a simple cycle turbine plant.

These conclusions are qualitatively the same for CAES plants of 150 MW capacity. From the data in Appendix E it can be seen that the unit storage costs for 4 hour or 8 hour, 150 MW conventional or solution mined caverns are 40 to 150 percent more than for the unit costs for caverns for 600 MW plants. For aquifer storage, unit costs of storage for the 150 MW plants are approximately 20 percent more than those of the 600 MW plants. Since turbomachinery and balance of plant costs scale in an approximately linear fashion with generation rating, the investment cost elements (mills/kWh) for 150 MW plants are larger than those for the 600 MW plants in Tables 4-6 through 4-9. The total generation costs for the smaller plants are therefore larger than for either the 600 MW CAES or 150 MW S/C gas turbine plant alternatives.

Generally lower pressure storage is economically favored for CAES systems. Thus, the advantage of substantially reduced storage costs achieved by increasing the pressure and depth of storage is more than offset by the increased investment in compressors and the larger cost of compression energy. An exception is that for conventionally mined, compensated storage: the total costs appear to pass through a shallow minimum. For the designs employed in this assessment, the major contribution to increased compression energy cost is that of the heat rejection during compression. Flow losses in piping and porous rock reservoirs make only a small contribution to the total compression energy costs. These conclusions appear to be insensitive to size of plant or to the number of hours of annual operation.

This economic assessment indicates that a utility would have chosen CAES as an alternative to peaking turbines to meet 1975 needs only under exceptional circumstances, e.g., an exceptionally low offpeak energy cost, or an exceptionally high turbine fuel cost, or limited fuel availability. However, this conclusion need no longer hold for a utility planning to meets its 1981 peaking requirements. This can be appreciated from consideration of the total generation costs compiled in Table 4-10. These costs were derived by assuming that construction of each plant was begun at the appropriate time between 1976 and 1980 so that the plant could be operated at full capacity in 1981. Interest during construction, escalation, and investment costs, were added to the 1975 capital costs using the assumptions in Table 4-5, assuming a schedule of funds commitment for the storage linearized over the construction period. Escalation and interest on the turbomachinery was calculated based on placing the equipment order in 1978. The operating and maintenance cost was based on 6 percent annual escalation from 1975. A 1981 fuel cost of $3.44/MBtu was based on 6 percent annual escalation from $3.25/MBtu in 1980. The compression energy cost of $10/MWh was based on the assumption that incremental fuel costs will escalate at a substantially lower rate than other utility costs.

Table 4-10

1981 GENERATION COSTS FOR 600 MW PLANT OPERATED 8 HRS/DAY WITH A COMPRESSION ENERGY COST OF $10/MWh

Configuration	Total Generation Cost (mills/kWh)	Cost Elements (mills/kWh)			
		Investment	Fuel	Compression Energy	Operating and Maintenance
Simple cycle gas turbine plant	56.2	14.5	38.9	--	2.8
CAES: Conventional cavern, compensated, atm					
12	72.5	45.3	18.1	6.3	2.8
40	65.1	34.5	18.1	9.7	2.8
40 EXP[a]	63.1	33.4	17.2	9.7	2.8
80	68.6	36.6	18.1	11.1	2.8
CAES: Conventional cavern, uncompensated, atm					
40-20	71.1	41.6	18.1	8.6	2.8
80-40	72.3	41.0	18.1	10.4	2.8
80-40 EXP[a]	68.3	37.9	17.2	10.4	2.8
80-12	67.5	36.2	18.1	10.4	2.8
CAES: Solution cavern, compensated, atm					
12	57.4	30.2	18.1	6.3	2.8
40	60.1	29.5	18.1	9.7	2.8
40 EXP[a]	58.5	28.8	17.2	9.7	2.8
80	62.1	30.1	18.1	11.1	2.8
CAES: Solution cavern, uncompensated, atm					
20-12	53.5	25.7	18.1	6.9	2.8
40-20	58.4	28.9	18.1	8.6	2.8
80-40	62.0	30.7	18.1	10.4	2.8
80-40 EXP[a]	60.5	30.1	17.2	10.4	2.8
CAES: Aquifer storage, atm					
12	55.2	27.1	18.1	7.2	2.8
40	61.5	30.5	18.1	10.1	2.8
40 EXP[a]	59.7	29.6	17.2	10.1	2.8
80	67.1	35.0	18.1	11.2	2.8

a) High pressure recuperator/expander system with generation rating 788 MW.

In addition to the base systems considered previously, the effect on generation costs of employing the cycle incorporating a high pressure recuperator/expander was included. The inclusion of the expander increases the output of the plant to 788 MW and reduces the heat rate to 5015 Btu/kWh. For the cases considered, the generation costs employing this cycle are 1.5-2.0 mills/kWh lower than the corresponding costs for the basic cycle.

An examination of the total generation costs in Table 4-10 indicates that CAES employing low pressure storage in either aquifers or solution mined caverns are now economically favored alternatives. The total incremental investment cost and compression energy cost for a CAES plant with equivalent generation costs to those of a simple cycle turbine plant is 35.3 mills/kWh. This quantity is greatly affected by the cost of combustion turbine fuel. The costs of combustion turbine fuel in 1981 corresponding to equivalent generation costs for a CAES plant with those of a gas turbine plant are compiled in Table 4-11.

Table 4-11

1981 BREAKEVEN FUEL COSTS

CAES	Fuel Cost ($/MBtu)
Conventional cavern, compensated, atm	
12	6.13
40	4.91
40 EXP	4.55
80	5.48
Conventional cavern, uncompensated, atm	
40-20	5.90
80-40	6.10
80-40 EXP	5.38
80-12	5.31
Solution cavern, compensated, atm	
12	3.63
40	4.08
40 EXP	3.82
80	4.41
Solution cavern, uncompensated, atm	
20-12	2.99
40-20	3.80
80-40	4.40
80-40 EXP	4.14
Aquifer storage, atm	
12	3.27
40	4.32
40 EXP	4.01
80	5.24

For a number of the CAES alternatives, the breakeven cost of fuel is sufficiently close to the range \$2.85 to \$3.55/MBtu in 1981 derivable from Table 4-2 that particularly favorable local conditions, either site or utility characteristics, could influence the decision on economic grounds. Under such circumstances, noneconomic factors, in particular, the reduced need for petroleum derived fuel, should incline the utility toward selection of a CAES system, provided that the reliability of the technology had been convincingly demonstrated.

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Section 5

INSTITUTIONAL CONSTRAINTS

5.1 INTRODUCTION

In addition to the technological and economic factors affecting the feasibility of compressed air storage a variety of other factors broadly characterized as institutional, might significantly affect the application of the technology for utility energy storage.

These institutional factors can be broadly classified as environmental, legal, and socio-economic. The primary concern in this report is with the way such issues are likely to favor or impede the introduction of CAES systems, either directly or indirectly.

Specific factors that will be considered are:

- Physical environment
- Social acceptability
- Materials and resources
- Labor and trade unions
- Legal and regulatory factors
- Contracting practices

Other factors that generally affect the ability to introduce new technology -- such as the nature of the financial constraints on the utility companies, particularly capital availability -- will also affect the extent to which compressed air storage will be applied. While these were not explicitly considered in this study, they should be taken into account in appraising the prospects for compressed air storage implementation.

The factors listed above will be analyzed with respect to the main configurations of the air store that are currently candidates for implementation. These are in compensated, conventionally mined caverns, in uncompensated, solution mined caverns, and in aquifers.

Effects of institutional factors have been assessed on an individual CAES system basis. The effects of the introduction and widespread utilization of CAES systems on a national scale received less attention, and perhaps should be studied at a later stage if the concept proves to to be feasible and attractive.

Most of the attention is focused on differential effects of the institutional factors with respect to a selected base case. For the purposes of this study, the base case will consist of a conventional gas turbine plant of equal power rating as the proposed CAES system, with no thermal storage. This base case was chosen because this type of peaking plant is the one most likely to be competitive with CAES systems. An analysis of the individual institutional factors follows.

5.2 PHYSICAL ENVIRONMENT

Environmental factors have received increasing attention in the last few years as the quality of the environment has become a primary concern of the American public. The widespread passage of legislation designed to protect the natural environment, and the action of organized citizens' groups in monitoring the inception and implementation of many projects that are likely to affect the environment, have resulted in the circumstance that virtually no major project is now undertaken without some kind of assessment of environmental impact. In particular, since many compressed air storage options employ fuel-fired turbines, the requirement to obtain a permit from the Federal Energy Administration (FEA) to burn oil will carry with it the need to supply an environmental impact statement. Failure to study and, to the extent possible, foresee the environmental implications of a project could cause considerable delay in its implementation as several authorities and the public scrutinize its environmental impacts.

In the environmental assessment of CAES systems that follows, an attempt has been made to discover as many areas of potential environmental impact as possible and to list them with a qualitative evaluation as to their likely magnitude and importance. Potentially beneficial, as well as adverse, environmental effects have been sought.

The assessment of environmental impacts has been divided into those related to the construction and operation of the underground storage chamber and associated works (including the surface reservoir of conventionally mined caverns with hydrostatic leg) and those related to the surface installations (including the central powerplant that powers the air compressors). An assessment of impacts on the land use around the CAES facility is also given.

ENVIRONMENTAL IMPACT OF THE STORAGE CHAMBER

The storage chamber is the most distinctive feature of CAES systems. It is also a completely new system with respect to the base case. Therefore, practically all the impacts from the storage chamber are differential impacts (Ref. 15).

Environmental impacts from the storage chamber occur in two phases: the construction phase, and the operational phase. Contamination or alteration of ground water is the primary environmental concern during both of these phases (Refs. 2, 9, and 16). Virtually any underground work will cause a change in ground water flow patterns and hydraulic balance, while the seepage of brines, drilling fluids, and drainage from tailings represents potential contaminants for ground water. The construction phase would involve, at the very least, the drilling of an access shaft and, except in the case of the aquifer storage, the creation of a cavern by conventional mining techniques or by solution mining (in the case of salt caverns).

Caverns excavated in hard rock such as granite and gneiss will present some of the greatest potential leakage problems because of their relatively high fracture and fissure permeability. During the testing of such environments for development of low-pressure-gas (LPG) storage caverns, permeable fractures and joints are often found to be separated by extensive zones of tight rock, which provide excellent product containment when mined. (In excavating a cavern it is not uncommon to intersect additional fractures and joints that leak up to several liters per hour into the opening; however, such inflows can usually be reduced to minimal amounts by grouting and other sealing techniques.) LPG storage caverns are designed so that the static water pressure is always greater than the pressure of the stored product and the ultimate sealant is actually provided by the hydrostatic pressure. In tight, dry conventional caverns the same criteria are used, but in this case the hydrostatic pressure is more correctly an additional safety factor in case the cavern conditions change. To date, product leakage out of such caverns has not been indicated either in nearby wells or in contaminated or altered ground water conditions.

Disposal of brines from solution mined caverns in salt beds presents a particular aspect of the general problem of environmentally acceptable disposal of mining wastes (Ref. 13). Unless a depleted oil or gas field that can receive the brines exists in the vicinity or the site is near a saline body of water, the brines will have to be disposed of by injection into an aquifer. The volume of brine generated from one solution mined cavern can be very large. Typically, this volume is about ten times the volume of the cavern.

Injection of brine into freshwater aquifers will certainly render them unfit as drinking or agricultural water supplies. Injection into saline aquifers, the more commonly practiced disposal method, is not without problems. Displacement of saline water may spill over into fresh water in the same or an adjacent aquifer. If the confining rock should be fractured or if the aquifer is faulted, saline water may migrate into freshwater aquifers at higher levels or even come out on the surface. Contamination of freshwater aquifers may also occur if a leakage in the injection well casing develops, or if saline water under pressure migrates vertically outside the casing. Finally, an abandoned well improperly plugged is a potential outlet for saline water into a freshwater aquifer.

There are other potential effects of brine injections in addition to contamination of fresh underground water. Pressure from the injection propagating through the aquifer can affect the performance of adjacent oil and gas wells. Even a recorded earthquake stimulation is believed to have been caused by a deep well injection in the vicinity of a fault zone.

Enough cases of undesirable effects from deep well injections have been recorded to warrant precautionary measures. A thorough geologic and hydrogeologic survey is necessary, and in many cases, is required by existing regulations. Unfractured beds of shale, clay, slate, anhydrite, gypsum, marl, or bentonite generally constitute good seals; limestone and dolomite are very often fractured. Careful testing and monitoring of the wells is also necessary.

While the solution mined caverns in salt beds may be the source of many potential hazards during the brine injection phase, they are the safest environmentally during the operational phase. This stems mainly from the fact that salt beds are watertight. The only differential environmental effect anticipated from compressed air storage in salt caverns is the possible carryover of salt particles from the cavern walls into the atmosphere.

In terms of environmental effects, aquifer storage seems to share some of the undesirable features of brine injections. The major difference is that the air pumped into the aquifer does not generally represent as serious a source of contamination as do brines. However, all the effects of increased pressure in the aquifer remain. If the storage takes place in a freshwater aquifer, adjacent freshwater wells are very likely to be affected. If the storage aquifer is saline, a potential for contamination of freshwater aquifers exists.

An example of ground-water disturbance due to gas storage in an aquifer is provided by the history of the Herscher natural gas storage project. The Herscher Anticline, located in Kankakee County, Illinois, has been used by the Natural Gas Pipeline Company of America to store natural gas in a closed aquifer reservoir, the Galesville formation, at a surface depth of 1, 750 feet. Injection of gas into the Galesville reservoir began in 1953 at a pressure of approximately 680 psi. Three months after inspection began, shallow water wells in the vicinity began bubbling natural gas. A search for the cause of leakage was unsuccessful, and it became necessary to undertake a broad approach to sealing the reservoir.

The method used was to pump water out of the Galesville formation outside the perimeter of the gas bubble (thus reducing the back pressure) and inject this water into the next higher permeable formation, the Potosi dolomite. In this manner the strata overlying the reservoir were hydrostatically pressurized, and became a satisfactory barrier to gas migration.

What little gas does escape is captured in vent wells drilled far below the potable water zone into the St. Peter and Galena formations. Since taking these corrective measures, the Herscher project has produced a highly successful storage reservoir.

The storage aquifer is subject to alteration in several ways. The possibility exists for blockage of water flow in the aquifer either by air bubbles or by mineral deposition. Aerobic bacteria may be introduced into the aquifer in contrast to the situation in natural gas storage. The flow and hydraulic balance of the aquifer may be altered. High temperatures may increase the mineralization of the groundwater. Finally, evaporation of the water during the cycling may deplete to a certain extent an aquifer with a very low recharge rate.

Several references have already been made to potential contamination of surface waters from the construction and operation of storage chambers. In the case of pressure compensation through hydrostatic leg the possibility exists for contamination of the surface reservoir with substances carried over from the storage chamber. A certain degradation of the chamber walls can be expected over a period of time, and the products of such degradation can be carried into the surface reservoir as well as into the ground water. If the reservoir is an artificial one the consequences of such pollution may not be important; but if a natural body of water is used, sensitivity to pollution increases, especially if wildlife is present or the water is also used for recreational purposes.

ENVIRONMENTAL IMPACT OF THE SURFACE FACILITIES

Most of the equipment used in surface installations is currently in existence in conventional gas turbine plants. However, its usage is different in CAES systems. Most notably, the fuel required for the operation of the gas turbine during the periods of peak demand is about one-half that used during the operation of a conventional gas turbine plant.

The direct result of this is a corresponding reduction of the cumulative air and noise emissions to about half. From the environmental point of view, this is the most significant advantage CAES systems will have over conventional gas turbine plants. One might also add a whole array of second order environmental benefits realized through the reduction of fuel requirements.

The reduction in oil used at the peaking plant site is partially offset by the emissions associated with the operation of the base load plant to provide pumping power during periods of offpeak demand.* A judgement concerning

* If the central powerplant is a nuclear facility, the pollution will be mainly thermal. In the case of a coal-fired plant, it will be primarily air pollution, but the use of scrubbers or fluidized bed combusion technology in the large plant should reduce this effect.

whether or not the net environmental effect is positive or negative will depend on weighing the significance of such factors as NO_x emission (thermal) or SO_x emissions. If compressed air storage is carried out without heat storage, then there will be greater requirements for heat rejection from intercoolers and aftercoolers in CAES systems than in a conventional gas turbine. Since cooling may be achieved by the use of air in dry-cooling towers, the increased heat rejection would not result in any currently acknowledged type of pollution.

Differential environmental effects from construction operations on the surface are generally negligible. There is no essential difference between the different types of CAES systems with respect to the environmental effects from surface installations. Any difference between the various systems with respect to such effects will arise from the construction and operation of the storage chambers, principally in the disposal of mining wastes and their effects on ground water.

5.3 LAND USE

The land use effects of CAES systems are a direct result of environmental factors to the extent that these factors favor or disfavor certain uses of land. One obvious land use effect would occur in the case of compensated systems with a surface artificial reservoir. The existence of such a reservoir would, of course, prevent the use of the land for any other reason. More complex is the effect of development of an aquifer plant with multiple wells and air collection systems on the use of the land overlying the aquifer. If the well spacing is large enough to permit employment of the forms of tillage economic in that area, then burial of the manifold to sufficient depth should permit dual use of the land. Close well spacing may effectively remove the land overlying the aquifer from agricultural use.

It is difficult to determine whether or not the national or site environmental situation will be improved or not by the introduction of compressed air storage. To arrive at a decision, it would be necessary to have a value system that allows comparison of different types of pollution, and of real impacts with potential impacts. Quantitative estimates of the various types of pollution might succeed in giving a better picture of the tradeoffs involved, but their magnitude is highly dependent on the specific situations at a CAES site. In any event, comparisons between the various types of CAES systems for a specific situation could be made with varying degrees of certainty, either with qualitative or with quantitative estimates of environmental effects.

5.4 SOCIAL ACCEPTABILITY

As with land use, social acceptability is to a large extent a direct result of environmental factors (Ref. 14). If less pollution is perceived on the surface with the introduction of compressed air storage than with the gas turbine plant, the social acceptability of the concept will be greater. Aesthetic factors play a role in determining social acceptability, but except for the potential secondary effects of mining there is no apparent basis for differentiating between compressed air storage plants and conventional gas turbine plants, since the major difference between the two types of systems, the cavern, is hidden in the ground. Economic factors generally play a role in social acceptability; except for the potential effect on land use of mining and drilling activities, the economic conditions created by any of the alternative systems are not markedly different from those of the base case.

One factor which may affect the social acceptability of the CAES concept relates to hazard. If residents of surrounding communities, rightly or wrongly, perceive the existence of an underground storage facility under pressure as a hazard to life and property, they may strenuously object to its presence in their midst. This factor could have significant consequences and should not be overlooked. A well-conceived community information program should help in this respect.

5.5 RESOURCE AVAILABILITY

The availability of certain resources required for the construction and operation of CAES systems represents a potential constraint on the implementation of the technology. In this subsection, the effects of availability of materials and equipment, human resources (skills), and industrial resources (underground construction firms) will be considered.

Given the relatively small fraction of any type of construction that CAES systems are likely to constitute, and the fact that they do not require inordinately large amounts of any particular resource, it is not expected that long-run effects of compressed air storage on resource availability will be significant. Only short-run direct effects of resource limitations on implementation of compressed air storage will, therefore, be considered.

MATERIALS AND EQUIPMENT

During 1974-1975, significant difficulties were experienced in the United States with respect to the availability of materials and equipment for use in construction, including some materials used in the construction and operation of CAES systems. A combination of factors, including relative unavailability of raw materials from overseas, inadequate domestic production capacity, a sudden increase in demand, and a sudden increase in the cost of energy, were responsible for rapidly rising prices and lengthening lead times.

While the situation has eased since the onset of the current recession, many of the underlying causes have continued to exist and problems may recur. A brief analysis of the situation is given below with respect to some materials and equipment that may present difficulties for CAES systems. The future situation will, of course, depend on what happens in the power field--in the construction sector in general, and in underground construction and mining in particular. While certain segments of the construction sector are currently depressed, the situation shows signs of improvement. Moreover, the current upsurge in coal production, which is likely to continue and expand, may create shortages in certain types of equipment used in conventional underground construction. An increase in the construction of power generation plants, which may be favored by government policy, would put a strain on available materials and equipment. To the extent that surface construction equipment will be needed in the construction of CAES systems, the upcoming construction of the Alaska pipeline is likely to cause delays and shortages.

Salt domes represent a limited resource, highly suited to implementation of compressed air storage, for which a serious competition in use may be developing because of their potential as relatively inexpensive sites for the storage of petroleum as part of a national strategic reserve. Land values over one such dome have recently increased to $100,000 per acre. Similar competition may develop between compressed air storage and synthetic, high-Btu gas storage in aquifers. Because of the substantial capital investment in natural gas storage plants, economics will probably dictate that they be run at constant, full capacity and the excess of supply over demand be stored in inexpensive underground areas such as aquifers.

Among the various materials used in construction and for power and construction equipment, steel in its various forms is the most important. Ordinary carbon steel is not anticipated to be in critically short supply, but under certain circumstances the situation may be marginal. The supply of specialty and alloyed steels, on the other hand, may be significantly short of demand. This is so because the United States is almost entirely dependent on foreign imports for the raw materials required for most alloying metals; e.g., manganese, chromium, and nickel.

In the area of fabricated metal products such as foundry products (forgings and castings) and mill products (sheets and plates), the situation with respect to castings and forgings remains one of concern. Foundry capacity has been sharply reduced in the last few years by marginal profitability and environmental constraints, which small operations could not cope with. Drilling rigs remain, and are expected to continue, in short supply, mainly as a result of a significant increase in underground explorations. National policy with respect to deregulation of oil prices and exploration of the coastal shelf should have a major impact on drilling rig availability.

Certain other construction equipment, especially the heavier units, are facing long lead times for delivery (up to two years). The situation is cushioned to a certain extent by the existence of a large market for used and rental equipment, but it could be exacerbated further before it improves. Availability of such items as roof bolts and valves for use in underground and general construction is also of potential concern. None of these constraints appear to be major limitations of the implementation of compressed air storage, however.

It is not anticipated that any of the CAES systems will use highly specialized equipment for its construction. With respect to equipment for surface installations, the major potential problems are related to the production of the specially designed gas turbines required for the operation of CAES systems. Some development engineering will be required for the separation of the gas turbine from the air compressor. The lead time for the development and production process is expected to be about three to four years. Lead times should drop to about two years for subsequently manufactured units.

HUMAN RESOURCES

The skills required in the construction and operation of CAES systems are currently available. Therefore, no significant manpower training programs are required. The current recession has significantly increased the unemployment rate in some sectors: some construction-related jobs are currently showing as much as 22 percent unemployment. In other sectors, however, including some types of mining, there are conditions of "full employment."

Mining engineers are currently in short supply, both because of a relative drop in enrollments in mining engineering curricula and because many are being hired by coal mining companies and by the Mining Enforcement and Safety Administration (MESA). Government efforts are currently underway to encourage increased enrollment in mining engineering schools, and these should have a secondary, positive effective on the implementation of compressed air storage.

INDUSTRIAL RESOURCES

The firms currently specializing in industrial and underground construction should be able to undertake construction of CAES systems with no major difficulty. There are many such firms, and the industry as a whole is easily expandable. The industry is accustomed to building novel or customized installations, and the size of the CAES projects is not large enough to create project management problems of a magnitude greater than those regularly dealt with by the industry.

5.6 LABOR AND TRADE UNIONS

Potential labor problems that may affect construction and operation of CAES systems involve mainly jurisdictional conflicts among competing labor unions. The construction of an underground storage chamber connected with and operated from installations on the surface presents opportunities for the occurrence of ambiguous situations in which it is not clear which union has jurisdiction.

At the outset, it appears, jurisdiction for most phases of underground construction belongs to the International Laborers Union (ILU-AFL/CIO). However, as construction and operation moves out of the ground, such other labor unions as the Operating Engineers, the Plumbers and Fitters, and the Electricians may be involved as well as members of the Teamsters Union.

Labor jurisdictional disputes are resolved largely by means of mechanisms established by the Taft-Hartley Act and its amendments, notably the National Labor Relations Board (NLRB). Several additional practices have been developed within certain sectors for the resolution of jurisdictional disputes. In the construction sector there is a plan for binding arbitration which includes the trade unions that are members of the AFL/CIO. However, contractors are not always bound by such arbitration, and if faced with a labor action (such as a strike) they may request the intervention of the NRLB, which has a broad range of options, from a temporary injunction to a court procedure. Jurisdictional disputes with unions outside the AFL/CIO may be harder to settle. The construction phase of a CAES system appears to be that during which jurisdictional disputes are most likely to arise, but the potentiality to delay the implementation of compressed air storage does not appear to be greater than that with other, already familiar power-generation plant construction.

5.7 LEGAL AND REGULATORY FACTORS

This is a category of very important factors. They are the ones that most prominently create the institutional setting within which CAES systems will function. Each of these factors imposes requirements that should be met before the system can be initiated and after it has been completed. The possibility of long delays and cost increases is therefore quite real. These factors consist of a collection of Federal and state laws and regulations and various standards and codes.

LEGAL FACTORS

The introduction of CAES systems raises certain interesting legal questions concerning underground and surface land ownership. Most of these questions arise in connection with the use of underground space for storage of compressed air. A preliminary analysis of the most important legal issues related to CAES systems, outlining their legal environment, is given below (Refs. 3 and 6). A detailed legal analysis of such systems is beyond the scope of this study.

To the extent that the underground has been used, it has historically been considered the property of the owner of the land surface directly above it. Theoretically this ownership extends to the center of the earth. However, only limited use has been made of the underground space, primarily in connection with the exploitation of mineral and groundwater resources. Technological, economic, and social factors have prevented the effective utilization of the underground at great depths, thus reducing its value to the owner as the depth increases.

It has been suggested that the underground space possesses similar characteristics to those of the air space. Since the legal status of air space ownership has been more thoroughly defined, the suggestion aims at applying the legal precedents created to the underground space. Currently, ownership of the air space extends to whatever height the owner can be reasonably expected to effectively use. The implication is that the air space above this limit is open to public use. The Federal Air Commerce Act of 1926 guarantees the free usage of such space for interstate and foreign air navigation.

If the same principles were applied to the underground space, the owner of the land surface would own the underground down to a "reasonable" depth and the rest of it would be free for public use. The user of such free space would have liability for any pollution or hazard he might impose. However, there are a few significant differences between the air space and the underground space. The existence of minerals and water in the underground makes this case more complex. It appears unlikely that property rights on such resources will be transfered without compensation. Moreover, even if ownership of the underground is limited in some way for the purposes of assuring free interstate transportation, the case of compressed air storage may be accorded a different treatment. The freedom of interstate commerce is guaranteed by the U.S. Constitution. No such guarantee exists for a power generating facility permanently stationed at one point. The conclusion is that a utility wishing to operate a CAES system will have to own the surface land above the underground storage chamber or will have to compensate the owner for the use of his underground space. (Both of these cases are discussed later in this sections.) The general legal situation, however, should be analogous to that involved in storing natural gas in aquifers or various petroleum products in solution or conventionally mined caverns.

To whatever depth ownership of the underground may extend, use of it may still be limited by the police power of the state. Such police power can be exercised over private ownership only in cases where the interests of the larger society conflict with private interests or when significant externalities arise.* Police power takes several forms. At the local level, zoning ordinances are the most common form.

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* An externality is an uncompensated cost or an unpaid-for benefit which one party incurs as a result of actions by another party. Air pollution by an industrial plant is an example of a negative (uncompensated cost imposing) externality for the general public; a beautiful private garden is an example of a positive (unpaid for benefit) externality for the neighbors.

Unlike the case of air space, zoning ordinances regulating the use of the underground do not generally exist and are not expected for some time, since the underground is far from being congested. It seems, though, that underground zoning will eventually come into existence as part of the current trend for three-dimensional zoning, especially in urban areas. The use of ground water is very likely to be one of the bases for such zoning. In the absence of underground zoning, the utility would probably have to compensate existing owners of adjacent properties for any taking of their property that may result from the construction of a CAES system. Subsequent owners would presumably not be compensated.

To the extent that use of the underground affects the quality of the environment or the safety of persons and properties, it is currently regulated by Federal, state, and local agencies through the issuance of licenses and permits. The surface installations of powerplants are generally subject to existing local zoning ordinances, although this authority has been preempted by some states on the grounds that a commission is regulating public utilities throughout the state.

The case in which the utility owns the surface land above the storage chamber presents the fewest legal problems. In this case the utility need only comply with all existing regulations and ordinances, and it can make use of the underground in any legal way it chooses, perhaps compensating some of the owners of adjacent properties. If the utility finds a suitable location for a CAES system and wishes to purchase the land it may not be able to do so, because of the owner's unwillingness to sell the property, a local ordinance, or because the land is already devoted to a public use. In this case, the utility has the options of either attempting to acquire only the use of the underground and locating the surface installations elsewhere, or attempting to use the power of eminent domain for the acquisition of the surface or the use of the underground. In some states, it is possible for a utility to be granted the power of eminent domain on the grounds that it serves a public purpose. Such power, however, is harder to justify against an existing ordinance or an existing public use. If the utility does not acquire the mineral rights of the property and discovers minerals during the excavations for the underground storage chamber, it will have to compensate the owner of such rights to the extent that it precludes his exploitation of the minerals. The use of salt beds and excavation of high-quality limestone are primary examples of this case.

The case of separate ownership of the surface and the underground is generally more complex. If a utility wishes to make use only of the underground for the location of a CAES chamber, it will have to acquire an easement or servitude from the surface owner and possibly adjacent land owners. Sums paid will depend on the depth of the facility and on the potential hazard it imposes, generally diminishing as the depth increases and the hazard decreases. The utility will also have to acquire some surface property on a fee simple basis for the servicing and operation of the underground facility.

The power of eminent domain could again be used in this case to acquire easements and fee simple property.

ENVIRONMENTAL LAWS AND REGULATIONS

Environmental laws and regulations have been playing an increasingly important role in the construction and operation of major industrial facilities, and especially of powerplants.

Since it is the differential impacts on CAES systems that this report is concerned with, and since these impacts are principally connected with the underground storage chamber and associated facilities, the emphasis in this subsection will be on the environmental laws and regulations that affect the construction and operation of the underground facilities. The part of the environment most likely to be affected by such facilities is the ground water and the aquifers in which it is contained. Most of the Federal and state laws and regulations that apply to ground water are actually general in scope and apply to all kinds of water. However, ground water is also covered under statutes referring to such areas as solid waste disposal, sanitation, and public health.

Beginning with Federal laws, the most pertinent piece of legislation is the Federal Water Pollution Control Act of 1972 (Public Law 92-500). Under this act, the Environmental Protection Agency (EPA) has the authority to issue water quality standards and require the states to establish programs to implement these standards. EPA is also obligated to issue guidelines and information for the implementation of the Act by the states. These guidelines include "all construction activity," "the disposal of pollutants in wells or subsurface excavations," and "changes in the movement, flow or circulation of .... ground waters" (Ref. 4). The Act also requires the issuance of Federal permits for "disposal of pollutants into wells" (Ref. 5). In addition, EPA has issued regulations requiring the issuance of permits by the states for actions likely to pollute ground water. Another relevant Federal law is the Solid Waste Disposal Act of 1970, which obligates the EPA to issue guidelines for the establishment of standards and regulations by the states, but grants no regulatory power to the Federal agency.

State environmental statutes and regulations that are likely to influence the construction and operation of underground facilities for CAES systems fall into three general categories: 1) water and water pollution statutes, 2) water well regulations, and 3) solid waste regulations (Ref. 1). Although no specific regulations exist, of course, for the type of underground facilities required for CAES systems, it is likely that in many cases they may be classified as wells (specifically injection wells), for purposes of regulation, especially when an aquifer is employed. When caverns are employed for storage, the underground facilities may fall under environmental regulations covering mines or tunnels.

Although numerous variations exist, many states require permits to be followed during the construction. These procedures generally include a geologic and geohydrologic survey, testing, the use of certain techniques during the construction to protect freshwater aquifers, and monitoring, as well as certain requirements to be met if the facility is to be abandoned. States in which a large portion of the water used by the residents comes from ground water are particularly strict.

Disposal of tailings from construction of caverns in solid rock are covered in many states by solid waste disposal statutes. Such statutes (currently in existence in 22 states) impose certain requirements on the sites and the manner in which disposal can be accomplished. Issuance of permits is required in most cases. Studies required typically include a geologic study, soils study, and water table mapping. In some cases control of leachates and monitoring wells are also required.

In addition to states, many counties and municipalities have ordinances of their own with respect to underground works. In most cases, these ordinances are comparable to the corresponding state statutes. In some cases, however, local ordinances are much stricter than state or Federal laws. For example, in Kern County, California, strict regulations with respect to ground water quality and even ground water temperature are in effect.

Of all the CAES system configurations, the one with an uncompensated cavern in dry rock is the least likely to encounter problems in complying with the laws and regulations discussed above. The aquifer facilities are more likely to have compliance problems, since they are interacting directly with an aquifer. Similarly, the disposal of waste from a solution mined underground facility is likely to raise compliance problems.

The construction and operation of hydrostatically compensated facilities should not encounter difficulty in meeting ground-water-related requirements, but the surface reservoir will have to comply with water quality statutes, especially if a natural body of water is used. Additional compliance problems may be created in this case if the surface body of water is used by wildlife as nesting grounds or by the public as a recreational facility. The effects of complying with all relevant statutes generally amount to time required for completion of all the requirements, which in some cases can be quite long, and monies expended during the course of compliance procedures. No general assessment of the impact can be made. Each site will have to be individually evaluated for its ability to meet not only geological and utility system requirements but also the constraints provided by compliance procedures.

While the underground facility chiefly introduces compliance problems, the situation with respect to surface installations is mixed. The applicable statutes here are air and noise pollution regulations and ordinances, plus water pollution regulations if there is heat rejection in the form of hot water from cooling towers. The water pollution statutes are in most case the same ones covering ground water pollution. With respect to thermal pollution it will be necessary to reduce the temperature of the cooling water below the required level, either by using cooling ponds or by mixing with cold water before discharge. It is proposed in Section 3 of this report that intercooling and aftercooling be accomplished by air cooling, in part to avoid the problems of regulations covering thermal pollution.

Air emissions are regulated by the states on the basis of air quality standards issued by EPA under authority granted by the Clean Air Act of 1970 (PL 91-604). Noise emissions are regulated by state and local governments. According to the Noise Control Act, EPA is authorized to issue noise regulations only for products, including equipment. So far EPA has not promulgated any noise regulations applying to any of the equipment involved in the surface facilities.

Cumulative air and noise emissions from gas turbines will be reduced, thus facilitating compliance with air quality regulations and with noise ordinances. On the other hand, since an increase in the base load would be necessary to generate power for the air compressors, an increase in whatever form of emission the central powerplant produces will result. Though the total effect on the environment may actually decrease, if the central powerplant is originally only marginally complying with the existing regulations, a slight increase in its emissions levels may increase the probability of noncompliance.

Different CAES systems configurations show little difference in their effect on surface installation. Therefore, there does not seem to be a question of preference of one type of system over another solely on the basis of easier compliance with regulation of pollutants emitted by the surface installations during its operation.

OCCUPATIONAL SAFETY AND HEALTH REGULATIONS AND OTHER STANDARDS AND CODES

Occupational safety and health standards and regulations for underground construction are promulgated by the Occupational Safety and Health Administration (OSHA) under authority of the Williams-Sterger Occupational Safety and Health Act. The regulations currently in effect are the general industrial standard (Section 1910 of OSHA Safety Standards), which regulates general industrial practices, and the more specific construction standard (Section 1926 of OSHA Safety Standards) (Ref. 7).

Subpart S of the construction standard deals with regulations pertaining to tunnels and shafts. General provisions cover access to working places, posting of hazardous places, and employee check-in/check-out systems.

Emergency provisions include formal evaluation plans and procedures and their dissemination to employees. Requirements on air quality and ventilation touch upon threshold limit values of airborne contaminants and the minimum allowable supply of fresh air. Procedures on illumination, fire prevention and control, personal protective equipment, noise, ground support, drilling, blasting, haulage, hoisting, and electrical equipment are laid down.

Subpart S also discusses procedures regulating the use of compressed air in underground construction. These pertain to employee education, medical care, attendance, examination, regulation, telephone and signal communication, signs and records, compression and decompression of chambers, compressor plant and air supply, ventilation and air quality, electricity, sanitation, fire prevention and protection, and bulkheads and safety screens.

These regulations will impede the acceptance by utilities of compressed air storage, inasmuch as the utility companies are sensitive to increases in underground construction costs. Although the immediate impact is expected to be increases in the cost of underground construction, the magnitude of these increases cannot as yet be estimated.

With respect to engineering codes, it appears that no established codes other than those for mining exist with respect to underground caverns. The American Society of Mechanical Engineers Standard for Pressure Vessels does not apply. However, the Underground Storage Committee of the American Gas Association is planning soon to issue guidelines and recommended practices for underground storage, which might be applicable in the case of aquifer storage.

5.8 UNDERGROUND CONSTRUCTION PRACTICES

A study of the feasibility of the undertaking of compressed air storage by utility companies must consider impeding factors associated with the necessary excavation of the underground storage cavern. Some of the existing underground construction practices may serve as severe obstacles to the use of CAES, and proposed reforms may either ameliorate these obstacles or worsen them. The purpose of this report is to point out those conditions unique to underground construction that are believed to be potential incentives or disincentives to the use of compressed air storage by utility companies.

Utilities are neither purely public nor purely private entities. Therefore, their required contracting procedure may deviate from the usual public or private method and may vary from state to state. For most construction in the United States, current practice is to use competitively bid, firm fixed price contracts. Underground construction is no exception, although its risky nature makes the use of contracts of this type lead to special problems.

ALLOCATION OF RISKS

Underground construction may be associated with manifold site specific problems. Although subsurface testing can be done, it is not until actual work has started that underground conditions are really known. The appropriate construction method may be quite different from that specified in the contract. Unexpected water conditions may arise. These unanticipated factors may cause the final cost of the construction to be greater than that anticipated when the bid was prepared. The question arises as to how these unanticipated costs should be allocated between the owner (e.g., utility company) and the contractor (Refs. 7, 10, and 12).

CURRENT PRACTICES

Under the usual existing bidding practice, contractors must be willing to accept the attendant risks of underground construction, since the typical contract is of the firm fixed price type. To allow for this risk, however, the prudent contractor uses bidding pricing that he estimates will provide him with a long-run profit, on the assumption that he can use his past experience to estimate the odds of successfully completing a given job within the quoted price.

Other costs also arise from the use of firm fixed price contracts in underground construction. For instance, under current bidding practices the owner must provide information to bidders on subsurface conditions. Since the owners do not have to accept final responsibility for the validity of the information, they have no incentive to spend their time or money on good preliminary site investigations. Bidders must either accept these results or do their own research; so there is considerable costly duplication of effort. These preliminary costs will be reflected in an increased bid price. The general opinion in the industry is that, over the life of the project, the owner will pay more for inadequate explorations than for a full study made before the start of construction.

Because of the great probability of changes in plans after the work has started, there are frequent instances of claims, disputes, and litigation. Owners and contractors take rigid positions, and solutions to conflict can be costly and time-consuming, thus, boosting construction costs. The rigidity of the contractual approach to underground construction may also discourage the use of improved technology and innovative construction techniques, thereby making underground construction generally less efficient and more costly than aboveground construction. The effect of all of these factors is to provide considerable margin for reduction in underground construction costs relative to surface construction costs through changes in contracting. Several recommendations have been made, which are designed to increase efficiency and reduce overall underground construction costs (Ref. 3).

RECOMMENDED PRACTICES

It has been recommended that the risks due to underground construction uncertainties be placed explicitly on the owner. This would have several cost-reducing effects. First, contractors would not have to employ a protective pricing reflecting their previous experience. Secondly, owners would have an incentive to do complete site investigations, and costly duplicative efforts by contractors would be unnecessary. Since the owners would accept responsibility for different-than-anticipated subsurface conditions, there would be no need for costly litigation. Finally, the owners would have an incentive to encourage innovative construction techniques.

Implementation of these recommendations has the potential to improve both owners' and contractors' situations.

5.9 PATENTS

The existence in force of patents covering key aspects of one or several of the technologies (e.g. turbomachinery, underground construction), that interact in a CAES system may provide either a constraint or an incentive to the implementation of a particular embodiment of compressed air storage. It is not within the scope of the present discussion to review the patent situation in those areas. In this section, a brief summary of patents whose sole application appears to be in CAES systems will be presented. Before the decision is made to build a compressed air plant of a particular design, a review of all the patent literature bearing on that specific embodiment should be conducted.

UNITED STATES PATENTS

W. S. Cook, "Compressed Air System," 1911 (Ref. 18). This patent does not bear directly on compressed air storage for utility applications. It is an example of the art concerned with compressed air storage in rock caverns to provide pneumatic power for mining equipment. A constant volume cavern is employed, with a windmill powering the compressor. Such a form of compressed air storage might be considered currently in connection with the application of wind power.

F. W. Gay, "Means For Storing Fluids For Power Generation," 1948 (Ref. 19). The inventor describes the use of gas turbines coupled to caverns to store compressed air and gas generated by running the gas turbines during offpeak periods. The air and gas are stored separately in underground chambers of novel design by displacing a fluid (e.g., water) from the chambers. Aftercoolers and a recuperator are part of one cycle he describes. During peak demand periods, the compressed air and gas are used to drive gas turbine-generator sets. The principal difference between this scheme and some described in the present report is that use was not made of energy taken from the utility network during offpeak periods to run the compressors.

H. A. Carlson (assigned to General Electric Company), "Spinning Reserve Peaking Gas Turbine," 1964 (Ref. 20). Compressed air produced by running a motor/compressor unit during offpeak periods is stored in "a series of interconnected caves, either natural or artificial," and released along with fuel to provide a quick start for a peaking gas turbine-generator unit. The emphasis is on using a gas turbine as spinning reserve; another means of accomplishing this, without using compressed air storage, is also described.

W. J. Lang, "Method and Apparatus for Increasing the Efficiency of Electric Generation Plants," 1970 (Ref. 21). Compressed air generated during offpeak periods is stored in porous aquifers with impermeable cap rocks, and is withdrawn to generate electric power as required. Ranges of permeabilities, porosities, and pressures are specified. The patent presents representations of a reversible air motor/air compressor and of separate electrically driven air compressor and gas turbine-generator units connected to the aquifer air store.

W. J. Lang, "Method and Apparatus for Generating Power," 1970 (Ref. 22). The use of brine displacement from a rock or salt cavern to maintain constant pressure on compressed air stored in the cavern is described. The air is compressed during low load periods, using electric power from a utility grid, and is expanded to generate electricity during peak periods.

I. Janelid, "Power Plant Driven by a Gas Turbine, and a Method of Operating Such a Powerplant," 1972 (Ref. 23). This presents a means of boosting the pressure level in a water leg compensated air store by employing two reservoirs or an additional hydraulic pump. In one method described in this patent, water from the storage volume is ordinarily pumped out at one level, but when extra pressure for additional power is required, the water column to the normal (lower) reservoir is closed off and water is admitted from a higher reservoir.

S. L. Koutz (assigned to Gulf Oil Corporation, Pittsburgh, P.), "Energy Storage System and Method," 1972 (Ref. 24). This patent describes the basic CAES cycle in which the heat of compression generated during the charging period is stored and used to heat the air coming from the reservoir during the generation period (the adiabatic cycle). A specific embodiment employing crushed rock in an underground cavern acts as the heat storage medium, and a water compensated air storage cavern is described. The patent also describes a cycle in which only a portion of the heat needed for the expansion phase comes from storage, the balance coming from a supplementary heater.

G. A. Rigollot, "Power-Generating Plant Using a Combined Gas-and-Steam-Turbine Cycle," 1973 (Ref. 25). A combined steam and gas turbine cycle coupled with an underground air storage reservoir is described. In addition, an air liquefaction/distillation plant is included to provide oxygen-enriched air to the steam boiler and air/nitrogen mixture to the turbine.

T. Schwartz (assigned to Kraftwerk Union Aktiengesellschaft), "Gas Turbine Air Storage System," 1974 (Ref. 26). An improvement on the method of storing compressed air in an uncompensated salt cavern is described. A design of the air withdrawal piping within the cavern and cavern shaft is presented which is intended to prevent moisture from condensing on unprotected metal.

F. V. Flynt (assigned to General Electric Company), "Pumped Air Storage Peaking Power System Using a Single-Shaft Gas Turbine-Generator Unit," 1974 (Ref. 27). This describes a means of modifying a single shaft compressor-turbine-generator unit so that it can be used for compressed air storage without introducing disconnectable couplings in the shaft. Valving is used to divert the air from the compressor and windmilling turbine driven by the motor during offpeak periods. The air is stored in a cavern and released during the peak period through a combustor into a turbine that now drives the generator. Steam injection can be used to reduce turbine windage losses.

G. A. Rigollot, "Method and Plant for the Storage and Recovery of Energy from a Reservoir," 1975 (Ref. 28). A method to avoid the champagne effect is described in this patent. By means of a one-way valve, the ascending column of air-saturated water is diluted with water from the surface reservoir that does not contain substantial amounts of dissolved air.

FOREIGN PATENTS

Svenska Turbinfabriks Aktiebolaget Ljungstrom (STAL), "Improvements in a Gas Turbine Plant Operating on the Open System, for Delivering a Large Useful Power of Short Duration," 1952: Great Britain and Sweden (Refs. 29 and 30). A peaking plant is set forth, using an independent combustion turbine and compressor with a water leg compensated cavern to store compressed air generated by driving the compressor off the electric grid during offpeak perids.

B. D. Djordjevic, "Gas Turbine Installation for Energy Storage," 1960: France (Ref. 31). Two methods are described for storing compressed air: in a subterranean aquifer with an impermeable cap, and in a submarine vessel. The application includes a combustion turbine for storing offpeak energy.

B. D. Djordjevic, "Gas Turbine Power Plant," 1960 Canada (Ref. 32). This patent describes a gas turbine plus air storage to provide peaking power.

Z. Jaroszewicz, 1963: Poland (Ref. 33). Use of a water leg compensated cavern with a segmented combustion turbine is proposed. A single motor/generator unit between the compressor and turbine is described.

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5-24. United States Patent 3,677,008, Energy Storage System and Method (July 18, 1972).

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5-31. France Patent 1,209,936, Gas Turbine Installation for Energy Storage (March 4, 1960).

5-32. Canada Patent 596277, Gas Turbine Power Plant (April 19, 1960).

5-33. Poland Patent 46525 (March 25, 1963).

Section 6

POTENTIAL FOR UTILITIES APPLICATION

The factors influencing the application of compressed air storage technology by utilities can be divided into those intrinsic to the technology, such as siting requirements, costs, availability of components, and those intrinsic to specific utility systems, such as the existence of a peak demand growth, the availability of offpeak energy at a low incremental cost relative to onpeak energy and the suitability of other storage options to meet the utility need. A third set of factors might be considered: those imposed by the constraints of the environment in which the implementation takes place. To the extent that it has appeared possible to quantify them, the effects of these constraints have been taken into account in developing the costs for CAES systems. Thus, included in the cost have been charges for disposal of brine or waste rock in an environmentally acceptable fashion, the use of dry cooling to avoid thermal pollution, the need to provide dual escapeways for underground workers during construction, the increasing land costs associated with salt domes because of their potential as hosts for hydrocarbon storage and the added interest during construction caused by licensing requirements.

Other environmental constraints are not quantifiable at present. For example, for winter peaking utilities, a conflict between the need to provide distillate fuel to heat homes because of a decreasing availability of natural gas and the need to provide distillate fuel for utilities peaking could profoundly affect their decision to commit to oil-consuming peaking systems. For all utilities, the absence of a nationally assured supply of distillate fuel in the event of political action by oil producing nations could similarly influence their decisions to build compressed air plants. It may be anticipated that these factors of oil availability will reflect themselves ultimately in the cost of fuel, and that the assumptions made in developing the sent-out costs in Section 4 in the long run will adequately measure the effect of these constraints. In the short run, however, the lack of an assured fuel supply for utilities to use in CAES systems may delay implementation of the technology.

6.1 GEOGRAPHIC ASSESSMENT

The siting constraints on compressed air storage, determined by the availability of suitable formations near transmission corridors, will be a major factor in the application of compressed air storage, and each mode of underground storage will apply targeting to a different region of the United States. Thus storage in salt caverns will be implementable only in the areas indicated in Figure 3-19 and Appendix B, "Salt Formations in the United States." Comparison of the distribution of salt domes, Figure B-3 and the Federal Power Commission map of electric power generation and transmission facilities indicates that the following utility networks may have a suitable relationship between their power facilities and potential air storage sites (Ref. 1):

Alabama Power Co.	4342MW*	SERC*
Mississippi Power Co.	966	SERC
Mississippi Power & Light Co.	1343	SWPP
Louisiana Power & Light Co.	2096	SWPP
Central Louisiana Electric Co.	648	SWPP
Gulf States Utilities	3285	SWPP
Texas Power and Light Co.	3224	ERCOT
Houston Lighting and Power Co.	5530	ERCOT
Central Power and Light Co. (Texas)	1654	ERCOT

In addition, storage in what appear to be dome-like salt formations may be possible for:

Utah Power & Light	1271	WSCC
Arizona Public Service Co.	1410	WSCC
Salt River Project	1147	WSCC

From comparison of Figures B-1 and B-2 and the geographic distribution of power generation and transmission facilities, compressed air storage in bedded salt formations may be applicable to the following utilities:

Niagara Mohawk Power Corp.	4551	NPCC
New York State Electric & Gas Corp.	1556	NPCC
Pennsylvania Electric Co.	1629	MAAC
Cleveland Electric Illuminating Co.	2792	ECAR
Ohio Edison Co.	2880	ECAR
Detroit Edison Co.	5986	ECAR
Consumers Power Co. (Michigan)	3667	ECAR
Kansas Gas & Electric Co.	1079	SWPP
Kansas Power & Light Co.	1129	SWPP

The total peak load for these utilities is 29,000 MW for individual utilities with a potential for storage in salt domes and 25,300 MW for utilities with potential for storage in bedded salt.

Because the results in Section 4 of this report indicated that within the next decade only large CAES systems may have an economic advantage over S/C gas turbines, it is important to look at the potential for operation of CAES systems by power pools. The following pools appear to have potential

*Numbers refer to 1971 system peak demand and abbreviation refers to the regional reliability council to which the utility belongs.

for employing storage in salt domes:

Southern Company System	12487MW
Middle South Utilities System	6811
South Central Electric Companies*	17310
Texas Utilities System	7892

and in bedded salt:

New York Power Pool	18953
General Public Utilities Corp. (PJM)	8133
Central Area Power Coordinating Group	8741
Michigan Pool	9653
Missouri-Kansas Pool	4287

The situation with the New York Power Pool and the PJM system is that the potential bedded salt storage sites are at the extreme western end of their system, whereas a major part of the system load is at the eastern end. The east-west transmission system capability will therefore have a major effect on the application of compressed air storage to these pools. The load of the individual utilities in these pools that could make use of potential storage sites in their service area were therefore included in estimating the potential for application of compressed air storage in salt formations, but the pool's load was not included in the totals.

The 1971 United States cumulative peak load was 296,100 MW. Thus individual utilities might employ storage in domed salt to serve 9.8 percent of the nation's peak load, while those that might employ storage in bedded salt provided 8.5 percent of the nation's peak. Operating on a pooled basis, storage in salt domes might be applicable to 16.6 percent and in salt beds to 12.5 percent of the national peak load.

It is more difficult to estimate the potential for storage in aquifers, since the actual availability of aquifers suitable for compressed air storage has not been determined with sufficient detail. This determination will require that a state-by-state analysis and ultimately a site-by-site analysis employing drilling records, seismic information and ultimately field exploration be completed. At this stage of knowledge, by using as a guide the distribution of oil and gas-bearing structures and gas storage fields in the United States (Figures 3-22 and 3-25) a list of utilities for which storage in aquifers may be applicable has been prepared:

<u>NEW YORK</u>

Niagara Mohawk Power Corp.

*Includes Middle South Utilities

PENNSYLVANIA:
- Pennsylvania Electric Co.
- Pennsylvania Power Co.

WEST VIRGINIA:
- Appalachian Power Co.
- Ohio Power Co.
- Wheeling Electric Co.

OHIO:
- Ohio Valley Electric Corp.
- Ohio Power Co.
- Cincinnati Gas and Electric Co.
- Dayton Power and Light Co.
- Columbus and Southern Ohio Electric Co.
- Toledo Edison Co.
- Ohio Edison Co.
- Cleveland Electric Illuminating Co.

KENTUCKY:
- Kentucky Utilities Co.
- The Kentucky Power Co.
- Tennessee Valley Authority

INDIANA:
- Indiana and Michigan Electric Company
- Public Service Company of Indiana
- Southern Indiana Gas and Electric Co.
- Northern Indiana Public Service Co.
- Public Service Company of Indiana, Inc.

MICHIGAN:
- Consumers Power Co.
- Detroit Edison Co.

ILLINOIS:
- Central Illinois Public Service Co.
- Commonwealth Edison Co.
- Illinois Power Co.

ALABAMA:
- Alabama Power Co.

ARKANSAS:
- Arkansas Power and Light Co.

LOUISIANA:
- Louisiana Power and Light Co.
- Gulf States Utilities
- Southwestern Electric Power Co.

TEXAS:
- Houston Light and Power
- Texas Power and Light
- Southwestern Public Service Co.
- Texas Electric Service Co.
- Lower Colorado River Authority
- Central Power and Light Co.

OKLAHOMA:
- Public Service of Oklahoma
- Oklahoma Gas and Electric

KANSAS:
- Kansas Gas and Electric
- Kansas Power and Light

IOWA:
- Iowa Power & Light Co.
- Iowa Electric Light & Power Co.
- Union Electric Co.

MISSISSIPPI:
- Mississippi Power and Light Co.

WYOMING:
- Pacific Power and Light Co.

COLORADO:
- Public Service of Colorado

NEW MEXICO:
- Public Service of New Mexico
- New Mexico Electric Service Co.

MONTANA:
- Montana Power Co.

UTAH:
- Utah Power and Light Co.

CALIFORNIA:

Southern California Edison Co.
Pacific Gas and Electric Co.
City of Los Angeles, Dept. of Water and Power
Sacramento Municipal Utility District

The aggregate peak load of these utilities was 148,100 MW in 1971, corresponding to 50 percent of the national aggregate peak demand. However, it is improbable that suitable closed structures will be identifiable in the service areas of all of the utilities in this list. On the other hand, potential aquifer storage sites may exist along the southeastern Atlantic coast, from approximately Washington, D. C. south, even though significant oil and gas deposits were not found in this region, and there has not been an economic incentive to develop natural gas aquifer storage in the area. As noted earlier, analysis of geological information and field studies will be required to further refine this estimate of the total potential for the application of compressed air storage in aquifers.

The situation with respect to storage in conventionally mined caverns requires a much more detailed analysis than can be carried out in the present study. As a first approximation it is possible, at a cost, to excavate a cavern in virtually any part of the United States. However, the economic assessment presented in Section 4 indicates that the incentive for this application may not be widespread among utilities until the later portion of the 1980's. Thus the potential for implementation within the next decade will probably be limited to exceptionally suitable sites in the northeastern United States (see Figure 3-17) where the alternatives available to the utility may be more costly or less available than that assumed in Section 4. A detailed analysis of sites in this region is required to define the potential. Such a study is already underway, started in parallel with the work that led to the present report.

In summary, considerations of site availability indicate that the maximum impact of the modes of compressed air storage on the aggregate national peak is 29 percent for storage in salt and 50 percent for storage in aquifers. Generally where there is potential for storage in salt, there is also potential for storage in aquifers: only 1.6 percent of the peak load appears to be servable by storage in salt alone. The near equality of the economics of the two storage methods indicates that for pooled operation of compressed air storage, utilities serving about 27 percent of the peak demand may have the option of employing either method.

6.2 MARKET ESTIMATES

The geographic limitations on the implementation of compressed air storage provide a probable upper limit to the served market for CAES systems. Even with the potential for application, factors specific to each utility system will determine the decision to implement a CAES system. A number of these factors have been listed at the close of Section 2 of this report. Assuming that the technology is ready: a successful demonstration of the concept has been conducted, the favorable economic estimates are verified, the manufacturers stand ready to provide the equipment, the capability to construct the air store exists, and the potential institutional problems have been resolved; then to what extent and at what rate will penetration of the potential served market occur?

The answer to this question requires that each utility carry through its own analysis of system needs, employing an optimized generation planning program or some similar technique. However, some basis for a general estimate can be found. Previous analyses of energy storage requirements have indicated that 10 to 15 percent of a utility peak demand might be met by energy storage technology with the cost and performance characteristics of a CAES system (Refs. 2, 3). It is probable that over the next decade, the rate of implementation of compressed air storage may be determined by the rate of peak load growth in the United States, since the economic inducement to replace present peaking facilities with new technologies is not presently judged to be sufficient to cause their early retirement. Estimates of this growth rate are quite uncertain, but fall generally in the range of 4.5 to 7.0 percent per year. For example, the Federal Power Commission has forecast a 6.73 percent Electric energy growth rate in the next four decades. A value of 6.0 percent will be assumed here. Based on these assumptions, and the further assumption that conventional cavern storage will not be widely implemented until after 1985, then the CAES system will be competing in an annual market representing about 7.5 percent of the total installed generation capacity. Projections made in 1971 (Ref. 1), and now subject to substantial downward revision, were for a 1984 peak demand of approximately 700,000 MW, so that the total potential served market for CAES systems in 1985 might be of the order of 53,000 MW. If the incremental addition were approximately 40,000 MW, consistent with a 6 percent peak growth rate, then a 1985 market of about 3,000 MW for CAES may be estimated.

A driving force for implementation of storage is the presence of low incremental cost base load plants, such as nuclear plants in the utility system. There is even greater uncertainty concerning the rate at which utilities will introduce these plants. If the present trend to deferral or cancellation by utilities continues, then the implementation of compressed air storage may be retarded. The effect of this consideration has not been factored into any market estimate since the situation changes so rapidly (Ref. 5). However, the installed nuclear plant as a function of system capacity provides a guide to utilities that may currently have favorable incremental offpeak energy costs (Ref 1):

Wisconsin - Michigan Power Co.	77.5%
Rochester Gas and Electric Corp.	43.2%
Jersey Central Power and Light Co.	33.2%

Western Massachusetts Electric Co.	21.1%
Northern States Power Co.	17.5%
Connecticut Light and Power Co.	16.7%
Consumers Power Co. (Michigan)	16.1%
Carolina Power and Light Co.	16.0%
Hartford Electric Light Co.	15.6%
Niagara Mohawk Power Corp.	14.9%
Commonwealth Edison Co.	12.1%
Wisconsin Electric Power Co.	8.9%
Pacific Gas and Electric Co.	6.6%
Georgia Power Co.	6.3%
San Diego Gas and Electric Co.	5.0%
Southern California Edison Co.	2.9%

However, this is by no means a certain guide - the utilities load factor and installed pumped hydroelectric capacity must also be taken into account, and, more particularly, their planned, not existing, generation mix.

The gross estimate may be further refined by examining regional variations in load growth. The projected annual load growth by regional reliability council is as follows (Ref. 1):

	Growth	1984 Peak
Southwest Power Pool	9.6%	70,000 MW
Electric Reliability Council of Texas	8.2%	50,000
Southeastern Electric Reliability Council	8.0%	158,000
Northeast Power Coordinating Council	7.7%	82,000
Mid-Continent Area Reliability Coordination Agreement	7.1%	27,000
East Central Area Reliability Coordination Agreement	5.8%	99,000
Western Systems Coordinating Council	5.6%	109,000
Mid-Atlantic Area Council	5.1%	51,000
Mid-American Interpool Network	5.0%	57,000

It appears that areas of higher than average growth are also potential areas for storage in salt or aquifers.

As noted previously to provide a verification of the preliminary gross estimate of market potential, it will be necessary to apply the generation planning approach used by utilities. Current utility interest in compressed air storage provides a guide, in addition to the conclusions of the technical and economic assessment, to appropriate systems to investigate. With respect to conventional cavern storage, present interest has been identified by a utility in the Maryland area, and lack of interest by utilities in New Jersey and eastern Pennsylvania. One midwestern utility is doing the preliminary planning for a storage facility in an aquifer and another has expressed an interest in an aquifer CAES system. Two utilities on the Gulf

Coast have expressed interest in storage in salt domes in their areas, but the degree of the opportunity for the utility systems needs to be evaluated.

6.3 SUMMARY

One of the most important factors in estimating the extent to which utilities may apply CAES is that of the geography and the relationship of suitable storage sites to transmission corridors. In the case of storage in salt, using solution caverns, or conventionally mined caverns, it is possible to arrive at an estimate of the availability of sites to utilities by comparing the location of salt domes and bedded salt with the location of transmission corridors. In this way, using the 1971 figures for peak generation, it is estimated that a total of 52, 185 MW is provided by utilities geographically situated to employ CAES in salt. These utilities represent 17.6 percent of the peak generation in the United States in 1971. The East Central Area Reliability Coordination Agreement Area (ECAR) is the largest single group of utilities in terms of generation capacity that potentially might employ storage in salt. Extensive application of CAES in solution-mined caverns, by utilities belonging to the Electric Reliability Council of Texas and the Southwest Power Pool, has a significant potential. It is more difficult to estimate the potential for storage in aquifers since sites for compressed air storage in aquifers have not been identified with the precision possible for salt storage. Based on regional geology, it can be estimated that utilities serving 148, 100 MW or about 50 percent of the United States peak demand in 1971, are in areas potentially suitable for aquifer storage. Because of the relatively unattractive economics of storage in mined caverns, such storage was not included in the estimate of the potential for implementation. However, particularly in the northeastern United States, there will be sites specially suited for compressed air energy storage which should add to the extent to which CAES technology is implemented.

There are many other factors besides geography that must be considered in estimating the extent to which utilities may employ CAES. For example, the characteristics of the technology, in particular system reliability and component availability, the environmental constraints applicable to a particular utility, the utility load characteristics, peak demand growth rate, and the availability of low cost offpeak energy will influence the utilities decision among alternatives. A particular environmental constraint, very difficult to quantify at this time, is the availability to the utility of a secure supply of oil to meet peak power demands. In the near future, at least, availability of capital provides a constraint for a number of utilities. Because of this complex of factors, there is considerable uncertainty in any estimate of the potential for the implementation of CAES. A basis for an estimate is provided by the results of studies of implementation of energy storage, in particular batteries, in utilities generation expansion. These studies indicate that 10 to 15 percent of the generating capacity of the utility might be served by energy storage with the technology having the characteristics of CAES.

Based on a peak demand growth of 6 percent per year, an incremental 1985 addition of approximately 40,000 MW of capacity can be estimated. Geographic considerations indicate that salt or aquifer storage will be available to meet 52 percent of this demand. Thus, a 1985 market of the order of 2,000 to 4,000 MW/yr of additional capacity for CAES may be estimated.

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Section 7

DESIGN AND DEVELOPMENT PROGRAM FOR AN AQUIFER CAES PLANT

7.1 INTRODUCTION

Some major conclusions of the work described in the previous sections may be briefly summarized as follows:

- There appear to be no identifiable generally prevailing technical barriers preventing the application of CAES for energy storage by the utilities, but geological conditions at specific sites may limit or prevent its implementation.
- There are conditions under which CAES may be the most economical alternative to meet peak demand. These conditions are specific to a particular site both with regard to the geology and geography of the site and with regard to characteristics of the utility in whose service area the site is located.
- There are no institutional problems that will generally limit the implementation of CAES. However, considerations such as the requirement to dispose of waste from underground construction operations, or the potential for contamination of ground or surface water during operation of a CAES plant may provide constraints at specific sites.

To test these conclusions and to refine the technical and economic characteristics developed in Sections 3 and 4 of this report, the conceptual design of a CAES plant, using conditions prevailing at a specific site, was carried out. The results of that work are presented in this section. A design for a plant employing aquifer storage was selected because of indications, described in Appendix E, "Economics of Storage Development," that significant reductions in the estimated capital costs of such plants might result from refinement of the design. With the substantial cooperation of Commonwealth Edison Company, a survey of some of the potential aquifer storage sites in that utility's service area was carried out. Principal criteria for site selection were that there be a reasonable expectation that the site is geologically suited for compressed air storage, that the size be sufficient to meet Commonwealth Edison requirements, and that the potential availability of the site be such that it is conceptually possible to carry out a program of experimentation through the phases leading to a demonstration facility at the site. A secondary consideration was that the site be in proximity to an existing or planned transmission corridor. To provide enough information to meet the geological criterion, attention was focused on sites for which geological information is available from the experience of natural gas storage companies. A site near Brookville, Illinois, approximately 100 miles west of Chicago, was selected and the conceptual design for a CAES plant at that site was completed. The following sections describe this design, which is referred to, for convenience, as the Brookville Station.

7.2 SELECTION AND CHARACTERIZATION OF THE BROOKVILLE SITE

A preliminary search identified six potential aquifer storage sites within the Commonwealth Edison service area. The location of these sites is shown in Figure 7-1 and their characteristics summarized in Table 7-1. More detailed analysis revealed that the Leaf River site is probably not suitable because the caprock over the structure is cracked. The Pecatonica site is not located near either an existing or a planned transmission corridor and was therefore eliminated from further consideration. The structures at Herscher, Pontiac, and Troy Grove are now under lease and are being operated as gas storage facilities.

Table 7-1

SOME CHARACTERISTICS OF SITES CONSIDERED FOR COMPRESSED AIR STORAGE IN NORTHERN ILLINOIS (Ref. 3-15)

Site	(County) Location	Closure Volume (ft^3)	Average Porosity (%)	Average Permeability	Depth to Top (ft)	Present use	Proximity to 345 kV Transmission Lines
Brookville	Ogle 23, 23N-7E	2.37×10^{10}	18[a]	500[a]	672	None - abandoned	On proposed corridor
Herscher	Kankakee 30N-10E	3.48×10^{10}	18.0	467	1750	Gas storage	Remote from existing lines
Leaf River	Ogle L5N-9E	6.97×10^{9}	20.0	640	810	None - abandoned	Near proposed corridor
Pecatonica	Winnebago 27N-10E	4.30×10^{9}	18.6	556	800	Gas storage	Remote from existing lines
Pontiac	Livingston 27, 28N-6E	1.52×10^{10}[b]	10.0	25	3000	Gas storage	On existing line
Troy Grove	LaSalle 34, 35N-1E	4.18×10^{10}	17.0	150	1420	Gas storage	Near existing line

a) Estimated ; refer to text

b) Storage volume in use

While these structures are probably suitable for compressed air storage, they are currently unavailable for the purpose. Such sites may become available in the future. However, if a synthetic natural gas industry is to be developed in the United States, seasonal leveling of the output of these plants will be important to their economical operation. Thus there is a reasonable expectation that continuing storage of fuel gas in such aquifers will be required, and it was therefore judged that these sites do not meet the availability criterion of this study.

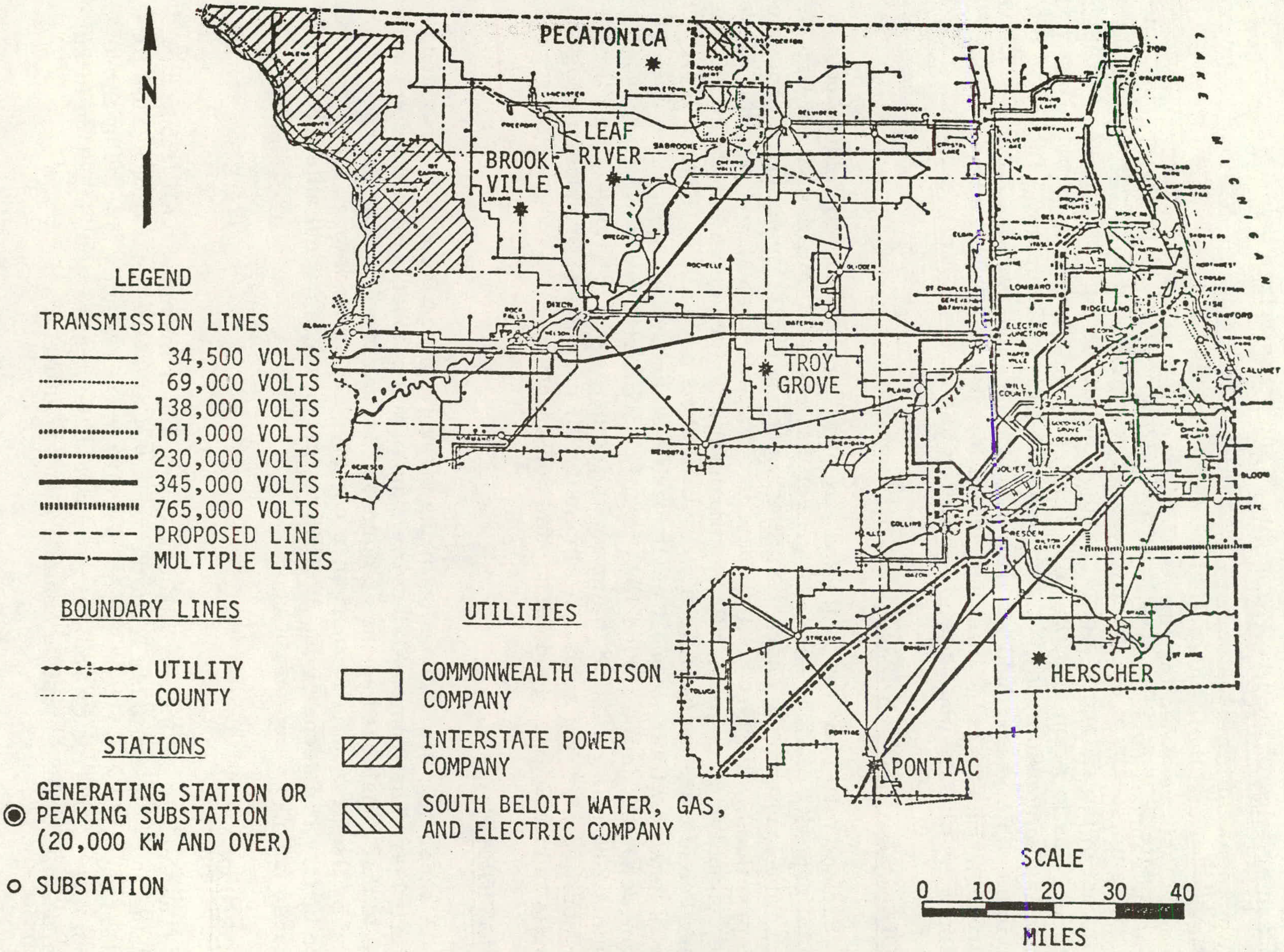

Figure 7-1. Location of Sites Considered for Compressed Air Storage

The Brookville structure meets the criteria as a site for carrying out the conceptual design. The characteristics of this site are described in Appendix F, "Characteristics of the Brookville Site," and summarized below.

LOCATION

The site is in a rural area in western Ogle County, Illinois, approximately 1.3 miles southeast of the unincorporated community of Brookville and 3 miles northwest of the village of Polo. Land at the site is currently in use for agriculture. The location is within 1 to 3 miles of the proposed Carroll County transmission corridor of the Commonwealth Edison Company. Access to the site is possible year-round via U.S. Highway 52, and the area is served by two railroads. Figure 7-2 shows the general location of the site and Figure 7-3 outlines the closure and shows its relation to nearby cultural features.

GEOLOGY AND SEISMOLOGY

Surface materials are soils and alluvium derived from and developed on glacial deposits of clay, sand and gravel that range in thickness from 8 to 75 feet. The load bearing characteristics appear suitable for standard construction practices. The Brookville Dome is a northwest-southeast trending structure, closed on both ends, with the northwest closure being the steeper of the two. The closure encompasses an area of about 4100 acres (Figure 7-3). The site is located within a Zone 1 earthquake risk area, indicated as an area of minor damage. In the period 1905 to 1972, six earthquakes were recorded within a 200 mile radius of the site with intensities in the range V to VII on the Modified Mercalli scale. An intensity VII earthquake produces negligible results in buildings of good design and construction.

STRATIGRAPHY

A schematic representation of the stratigraphy at the site is provided by Figure 7-4. The Ironton-Galesville sandstone enclosed within the dome structure is that considered as the compressed air reservoir. The caprock is provided by the Franconia formation, a complex set of sandstone, shale and dolomite beds. The deeper lying Mt. Simon formation is not suitable for storage because it lacks a competent caprock.

HYDROLOGY

The area is drained by Elkhorn Creek and numerous small tributaries. Potable water is available from the Ironton-Galesville formation. This formation supplies water to at least six wells in Ogle County, including those supplying the village of Polo. Drawdown of the aquifer and reduction in the formation pressure must be considered as a future possibility.

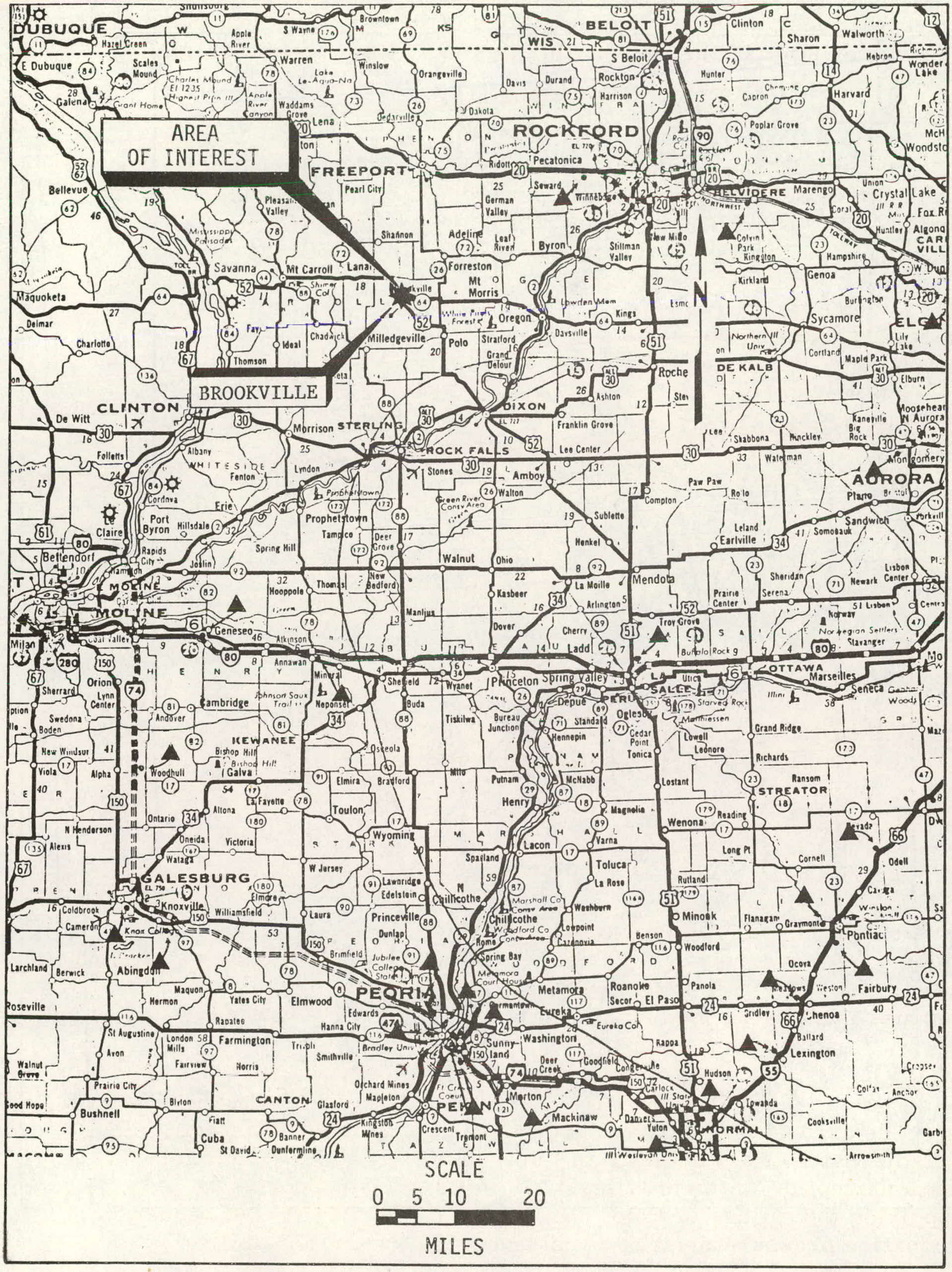

Figure 7-2. Location of Brookville Site

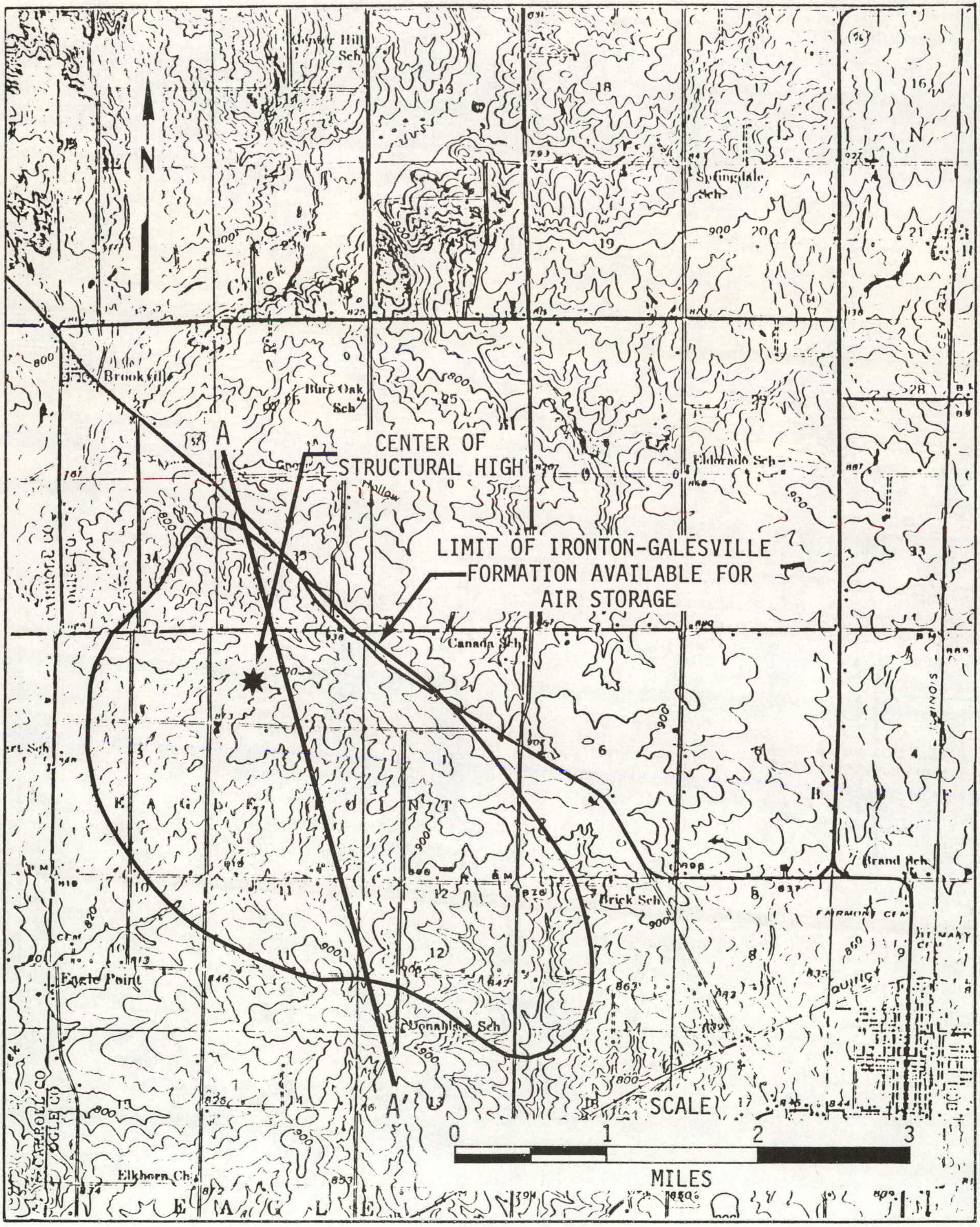

Figure 7-3. Topographic Map of Proposed Storage Area

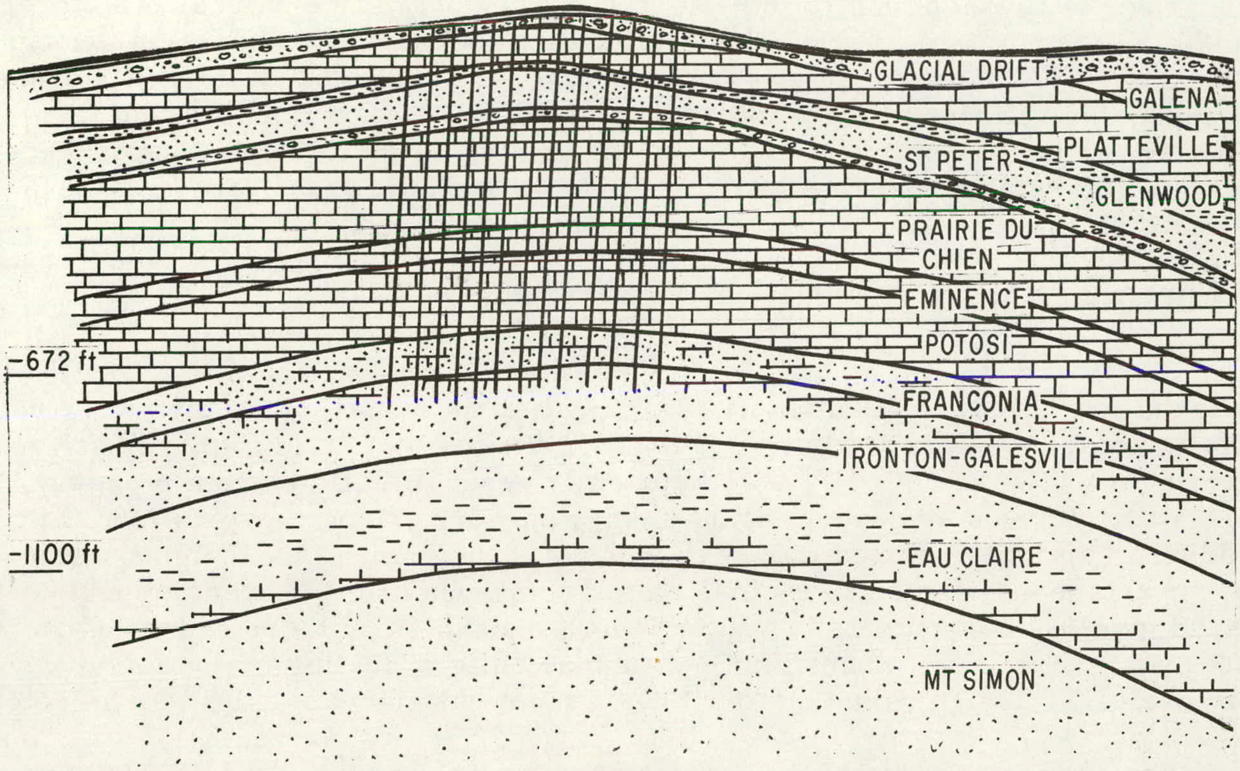

Figure 7-4. Schematic Representation of Stratigraphy at the Brookville Site

METEOROLOGY AND CLIMATOLOGY

Air quality standards can be met at the site employing established methods for gas turbine installations. Background concentrations of SO_2, NO_x, and particulates are typical of a rural area more than 30 miles downwind of a major industrial center. The area is subject to thunderstorms with wind velocities in excess of 50 miles per hour. The frequency of tornado activity at the site is estimated to be one event in 1000 years. The area is subject to temperature below 0 F with occasional heavy snows in winter, and to temperatures above 100 F and greater than 90 percent relative humidity in summer.

PRIOR WORK AT THE SITE

During 1964 and 1965, the Natural Gas Pipeline Company of America tested the Mt. Simon formation at the Brookville Dome as a natural gas storage reservoir. The geological results from this test confirmed the presence of the structure and have provided the data used in the present study. The 894 MMSCF of gas injected into the Mt. Simon in this test passed through the Eu Clair and Galesville formations and was stopped in the Ironton, immediately below the Franconia.

Further development of the site was not pursued since natural gas storage in the Franconia is not economically attractive because the formation pressure is much lower than pipeline pressures. After abandonment of the gas storage project, the gas was bled off into the atmosphere by a well drilled into the Ironton. This well was still releasing gas in 1974. While no estimates were made of the total quantity of gas bled from the Ironton, it appears that the Franconia in this instance served as a competent caprock.

7.3 DESIGN OF THE BROOKVILLE STORAGE FIELD

Once a site with the potential for meeting the requirements of a CAES plant is identified, the design process requires as initial inputs the power rating and duty cycle needed by the utility. In the present study, an ultimate generating capacity of 600 MW, a 10 hour daily generation time and a pumping cycle that derives 40 percent of its energy on weekends were specified. In addition, the utility stated that development of the plant in increments would be advantageous to achieve a close match between capacity expansion and demand growth. Increments of 150 MW were chosen since these represented the output from single industrial gas turbine units operating in the compressed air cycle. A design based on four nearly identical modular units was selected.

The characteristics of the turbines determine that the 600 MW field be capable of delivering 85×10^6 pounds of air per day at a minimum pressure of 170 psia at the regenerator inlet. Since the final reservoir must be stable and fixed in location, it is necessary that the time-pressure relationship be such that the average pressure in the formation during the weekly cycle be equal to the aquifer discovery pressure, and that the air reservoir be contained within the closure of the Brookville Dome. The reservoir meeting these requirements is called the equilibrium reservoir in this report. An upper safe pressure limit is set by the depth of the formation and the pressure gradient with depth appropriate to the area. Based on the experience of natural gas storage in aquifers in northern Illinois, a gradient of 0.6 psia/ft was used in this design. Important site characteristics are summarized in Table 7-2.

Table 7-2

CHARACTERISTICS OF THE BROOKVILLE AQUIFER
EMPLOYED IN THE DESIGN OF THE BROOKVILLE STATION

Permeability	500 millidarcy's
Compressibility	8×10^{-6}
Porosity	18%
Connate water	22%
Thickness	134 feet
Depth	672 feet
Discovery Pressure	240 psia
Caprock threshold pressure	> 163 psia
Initial temperature	60 F

The porosity, permeability, and connate water content were based on characteristics reported for the Ironton-Galesville formation, elsewhere in Illinois. The depth and thickness are based on the drilling logs compiled during development of the site. The value for the discovery pressure is taken from the literature, but could be neither confirmed nor refuted on the basis of available records. The compressibility is assumed; field studies to determine this important parameter have not been carried out at the site. The threshold pressure assumed is based on the experience of the engineers who carried out the tests of gas storage of the site, and should be confirmed by laboratory investigation. For a more detailed discussion of these characteristics, consult Appendix F.

The variables in the field design that must be specified are the total size of the air reservoir, the temperature of air storage, the spacing and size of the wells, and the diameter of the pipe used in the air collection manifold. The sequence of steps of the design process used in the present study started by estimating for the 600 MW equilibrium reservoir, the extent of water drive in a single reservoir supplying the entire 600 MW field. An alternative would be to base the design on individual smaller reservoirs around each well.* For the single reservoir, contraction of the reservoir water face during the weekly cycle will have a negligible effect on the pressure in the reservoir. The basis for this conclusion is described in Appendix G, "Brookville Reservoir Design." Therefore, for design purposes, the equilibrium air reservoir was treated as a fixed volume. This design approach is a conservative one since the effect of water drive will be to provide a more nearly constant operating pressure, resulting in a reduction in pressure losses and, therefore, pumping power costs.

The moisture balance and temperature of the air reservoir which were considered in the next step of the process are closely related. Appendix G, subsection 1 should be consulted for a detailed discussion. Condensation of moisture in the formation will interfere with airflow, resulting in unacceptable pressure losses or excessively low deliverability. Therefore, it will be necessary to dehumidify the air by chilling it to or below reservoir temperature, initially estimated to be 60 F. A heat pump plus heat exchanger as the aftercooler are needed to carry this out, because an air cooling system cannot be relied upon in the summer to provide temperatures lower than about 100 F. A penalty both in investment and in operating power must be paid to accomplish the chilling and reheating. As soon as the temperature in the reservoir exceeds 100 F, it should be possible to substitute the air cooling system for the heat pump. To provide a margin of safety in the event of very high ambient temperatures, a final reservoir temperature of 125 F was selected for the design. To stabilize the reservoir at this temperature, reheating of the air

* The alternative based on individual wells may not meet the stability requirement, since the air reservoir would not conform to the aquifer closure contours.

from the air cooled heat exchangers to a temperature of about 135 F is required. Allowing for 2 F cooling during travel through the manifold, the heat of vaporization of water picked up in the reservoir will just balance the heat released in the 8 F cooling of the injected air. The complete removal of the connate water in this fashion would require 21,000 cycles, or about 100 years at 200 cycles per year. At ambient temperatures below about -10 F, it will not be necessary to chill the compressor discharge before introducing the air into the reservoir, even at the initial 60 F reservoir temperature. However, moisture may condense from the residual air left in the manifold between the pumping and generation phases. Burial of the manifold will reduce the liklihood of this taking place. No special precautions appear to be needed to prevent damage to the recuperator or the turbomachinery on startup of the plant in the generation mode.

To achieve rapidly the stabilized operating condition, cooling of the air to 60 F and reheating to 200 F is proposed. The upper temperature limit is set by the ability of manifold and well casings to endure the daily temperature cycle. The average temperature in the reservoir can be brought to 125 F in about 6 to 8 years. If the 60 F chilling temperature is allowed to increase as the reservoir temperature rises, then the calculated time to reach 125 F is reduced by about 2 months.

DESIGN OF THE EQUILIBRIUM PLANT

For a reservoir with fixed walls, the larger the size of the reservoir relative to the volume of air cycled, the smaller the pressure variation during cycling. Reduced pressure variation results in lower pumping power losses, and and requires fewer wells to provide air at the required rate. These advantages of a large air cushion must be balanced against the increased investment in land, in the air collection manifold, and in the increased pumping cost for creating the reservoir. Limited size of the confining structure may place an additional constraint on the use of a large air cushion. While the Brookville Dome is large enough to accommodate a 30:1 air cushion for a plant of 600 MW, 10 hour capacity, the desirability of obtaining the maximum potential from the site also militates against the use of such a large air cushion.

The approach followed in the present study was to select the optimum size of the reservoir based on minimizing total investment required to develop the field. The sequence of steps required to accomplish this was as follows:

1. The maximum and minimum shut in pressure in the formation during the week for various total reservoir sizes were calculated. The method used is described in Appendix G.

2. For the minimum pressure during the weekly cycle (Friday evening), the number and spacing of wells required to provide 8.5×10^6 of air/hr at a pressure of 170 psia at the regenerator inlet were calculated.

The calculations of pressure drops in the formation and in the wells and air collection manifold are described in Appendix G.* The well casing size was selected on the basis of the cost of wells required to produce a specified wellhead pressure. The results, summarized in Table 7-3 were that in the pressure range relevant to the Brookville site, wells in 7 inch casings were, in every case, the most economical.

3. The cost of the air collection system, well drilling and initial air charging for three plant sizes covering a range of air cushion sizes are summarized in Table 7-4, and plotted for a 150 MW plant in Figure 7-5. It is evident that as more intensive use is made of the formation through cycling a larger fraction of air, the costs of initial air charging and of the manifold decrease, but the cost of well drilling increases. A minimum corresponding to about 12 percent of the air mass being cycled during the week is indicated. This was therefore selected as the design point for the equilibrium plant.

   One method that was considered for developing the field was to initially develop a 150 MW field at 7.5 percent cycling, and then rework the field by drilling and connecting additional wells until a deliverability for 600 MW with 30 percent cycling was obtained. Examination of Table 7-3 shows not only that this is economically disadvantageous compared to developing the 12 percent field, but that the nonlinear relationship between well spacing and fraction of air cycled makes this course impractical.

4. The final equilibrium design is based on four independent manifolds with wells spaced at 391 feet. This design meets all the criteria previously established. A schematic layout is provided in Figure 7-6. The details of the design and the associated investment are discussed in the section of this report dealing with the conceptual design of the plant. The characteristics of the final equilibrium design are summarized in Table 7-5. The specification of the pressure at the compressor outlet permitted the completion of the design of the compressor train for the 150 MW module, sized for a flow of 2.1×10^6 lb/hr. The details of the design and the associated investment are discussed in the conceptual design section of this report.

DEVELOPMENT TO EQUILIBRIUM DESIGN

The design developed by the sequence of steps outlined above leads to a 600 MW plant with a stable air reservoir that meets the storage and delivery

* Recent work in progress at Argonne National Laboratories indicates that the steady state approximation on which these calculations are based introduces an appreciable error into the calculation of pressure losses in the formation.

Table 7-3

COST COMPARISON OF WELLS WITH VARIOUS SIZES OF WELL CASING

Fraction Cycled (%)	Wellhead Del Pressure (atm)	CASING SIZE													
		5 1/2		7		8 5/8		10 3/4		13 3/8		16		20	
		Number of Wells	Cost ($$10^6$)	Number of Wells	Cost ($$10^6$)	Number of Wells	Cost ($$10^6$)	Number of Wells	Cost ($$10^6$)	Number of Wells	Cost ($$10^6$)	Number of Wells	Cost ($$10^6$)	Number of Wells	Cost ($$10^6$)
5	170	260	9.30	222	8.81	206	10.26	196	10.97	188	14.86	183	18.22	176	2.72
	176	280	10.01	240	9.53	223	11.10	213	11.93	205	16.20	199	19.81	192	23.67
	182	304	10.87	263	10.44	245	12.20	234	13.10	225	17.78	219	21.79	211	26.01
	188	335	11.97	292	11.59	273	13.59	262	14.67	252	19.87	245	24.38	236	29.08
10	170	279	9.97	238	9.45	220	10.96	210	11.76	201	15.88	195	19.41	188	23.20
	176	303	10.83	260	10.33	242	12.05	231	12.93	222	17.54	215	21.40	207	25.52
	182	333	11.90	289	11.47	269	13.39	257	14.38	247	19.51	240	23.90	231	28.46
	188	374	13.36	327	12.98	306	15.24	293	16.40	282	22.28	273	27.16	263	32.41
20	170	349	12.47	302	11.99	281	13.99	268	15.00	257	20.30	249	24.78	239	29.46
	176	394	14.08	344	13.66	321	15.98	307	17.18	294	23.51	285	28.35	274	33.77
	182	455	16.26	402	15.96	377	18.77	360	20.15	346	27.33	335	33.32	321	39.56
	188	550	19.65	491	19.49	463	23.04	443	24.79	426	33.65	412	40.98	395	48.66
30	170	521	18.61	462	18.33	434	21.60	415	23.24	398	31.43	385	38.30	369	45.46
	176	649	23.18	583	23.14	550	27.37	527	29.48	505	39.89	488	48.53	468	57.61
	182	885	31.61	807	31.90	765	38.07	733	40.75	703	55.52	680	67.61	650	80.00
	188	1519	54.26	1410	55.80	1343	66.80	1288	71.79	1234	97.44	1192	118.49	1138	140.10

Table 7-4

CAPITAL COST OF ALTERNATIVE AIR STORAGE RESERVOIRS

Cycled (%)	Power (MW)	Number of Wells	Well Spacing	Acreage	Manifold Cost ($10⁶)	Well Drilling Cost ($10⁶)	Initial Air Charging Cost ($10⁶)	Total Cost ($10⁶)	$/kW
5	150	66	658	656	12.22	2.62	0.21	15.05	100.3
7.5	150	70	525	443	7.33	2.78	0.14	10.25	68.3
25	150	120	220	200	4.70	4.77	0.04	9.51	63.4
30	150	202	153	108	5.35	8.02	0.03	13.40	89.3
15	300	166	340	441	12.83	6.59	0.14	19.56	65.2
20	600	398	268	656	37.36	15.80	0.21	43.37	72.3
30	600	788	155	435	24.22	31.28	0.14	55.64	92.7

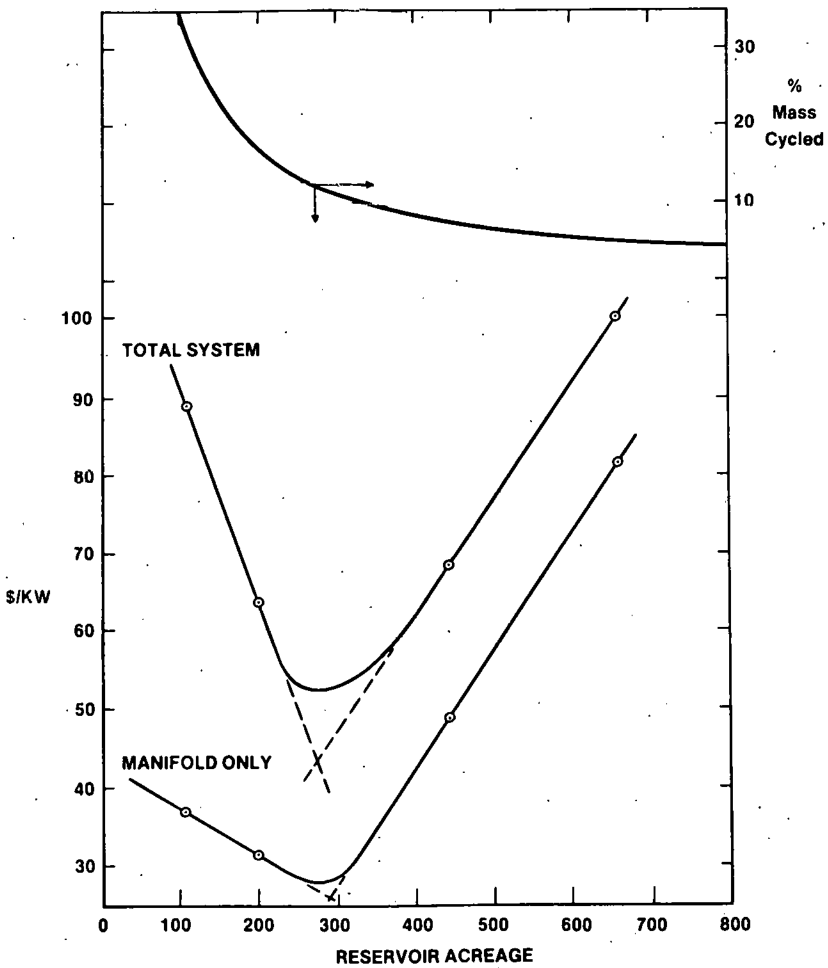

Figure 7-5. System Cost vs Acreage of Reservoir and Selection of the Most Economical Mass Cycling Percentage for 150 MW Plant at 125 F

Table 7-5

CHARACTERISTICS OF THE 600 MW EQUILIBRIUM AIR RESERVOIR DESIGN

Inventory of Stored Air ($\times 10^6$ lb)	
Maximum	1331.0
Weekly average	1247.5
Minimum	1171.3
Bottom Hole Flowing Pressures on Charge (psia)	
Maximum	284.4
Weekly average	269.3
Minimum	257.1
Bottom Hole Flowing Pressures on Discharge (psia)	
Maximum	224.5
Weekly average	205.6
Minimum	188.6
Water Front Pressures (psia)	
Maximum	256.1
Weekly average	240.0
Minimum	225.4
Pressure at Aftercooler Outlet (psia)	
Maximum	289.6
Weekly average	274.8
Minimum	262.9
Pressure at Throttle Valve Before Regenerator (psia)	
Maximum	207.4
Weekly average	189.1
Minimum	172.4
Wells	
Number	308
Spacing (feet)	391
Depth (feet)	739

requirements set by the utility duty cycle. A number of ways to develop the field to reach this final design were considered. The chief constraints considered were:

- Intermediate stages must allow for the addition of increments of 150 MW and 10 hour generation.
- As the reservoir is developed, it is assumed to conform to the contours of the dome.
- Any intermediate plants must use the well spacings and sizes appropriate to the final plant.

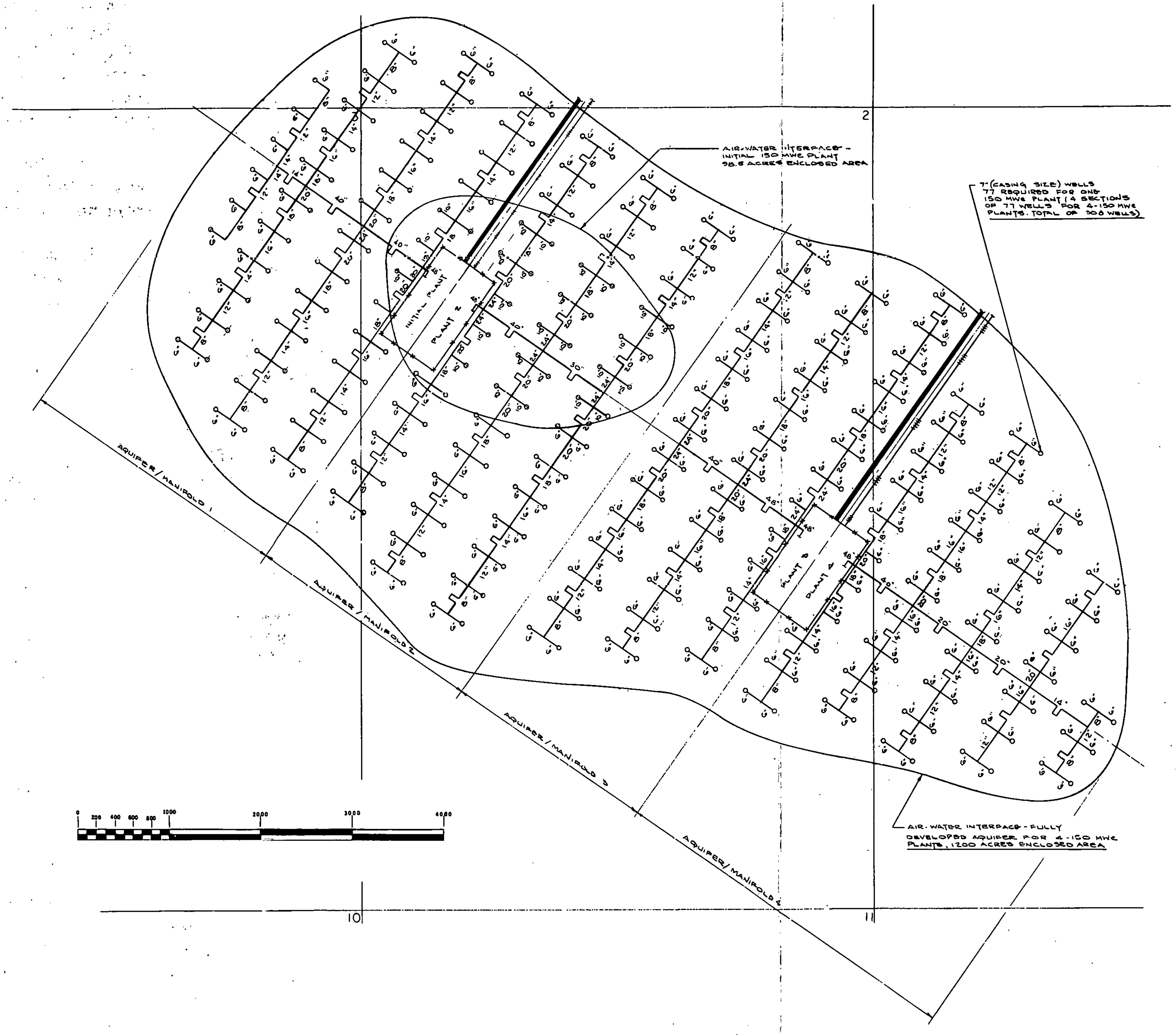

Figure 7-6. Layout of Equilibrium 600 MW Plant at the Brookville Site

Because the condition of constancy of air reservoir size is relaxed during the development period, the average weekly formation pressure need no longer be 240 psia. The constraint imposed on pressure during the development period is that the maximum formation pressure not exceed the caprock threshold pressure. In the design, a maximum bottom hole pressure of 403 psia was employed at the end of charge.

Two additional considerations in conceptualizing this design were that the time to install the first 150 MW plant be minimized and that the overall investment be kept to a minimum. Among the alternatives considered were:

1. Develop the equilibrium reservoir by simultaneously pumping on 308 wells at a compressor outlet pressure of 420 psia. After developing the reservoir, close off all but the wells needed to provide the air required for a 150 MW plant. Let down the pressure in the reservoir to a formation pressure of 284 psia through the first turbine and cycle 3 percent of the air mass stored in the reservoir. Install additional generating plants as the load growth on the utility requires.

2. Develop a 150 MW, 12 percent reservoir, at a formation pressure of 284 psia, by simultaneously injecting air into 77 wells in a pattern conforming to the contours of the dome. Install the 150 MW generation plant. When additional capacity is required, install a second 150 MW plant while doubling the reservoir size, drilling 77 more wells and reworking the single air collection manifold.

3. Develop a 150 MW reservoir at a formation pressure of 403 psia at the earliest possible time. Install the surface plant and begin cycling. Grow the air reservoir to its ultimate size from the single plant. When the air reservoir reaches the size required for the equilibrium plant, let down the pressure in the reservoir to 284 psia, and rework the compressor train to meet these pressure requirements. Develop additional capacity in the field by drilling and completing wells and manifold in the completed air reservoir.

4. Develop from 2 to 4 150 MW reservoirs at a formation pressure of 403 psia and proceed, as in Case 3 above, to the point that the individual reservoirs coalesce to the size required for the equilibrium design. Then rework the compressor trains, let down the reservoir to 284 psia and cycle as the equilibrium plant. Each of these alternatives permits orderly development of the site in 150 MW increments to the ultimate equilibrium design plant. In addition, each represents one of the combinations of choices the developer may make in responding to the following considerations:

   - The decision between developing the air reservoir completely before installing generating capacity versus developing the air reservoir in increments, matched to the incremental addition of generating capacity.

- The decision between employing a separate compressor-dehydrator facility for plant development versus developing the air reservoir by extending the weekly pumping time of a generating station.

There is a complex set of factors involved in consideration of these alternatives, affecting operating characteristics and investment requirements. Some of these considerations are summarized in Appendix G, subsection 5. It was decided for this study that the dominant considerations would be to reduce the risk inherent in developing a site by minimizing the investment required to obtain the initial 150 MW plant. This can be accomplished by selecting the third alternative, that of developing the field to its equilibrium size from a 150 MW plant operating at a compressor outlet pressure of 420 psia, while cycling that plant on the weekly cycle.

To carry out the development of the field, it was necessary to conceptually design a nonequilibrium 150 MW plant, called subsequently in this report, the initial plant. To design this plant, the following sequence of steps was followed:

1. The daily cycle was analyzed to determine the minimum pressure corresponding to cycling of several fractions of the stored air mass.

2. The volume of the reservoir corresponding to each fraction was calculated, and the corresponding area on the crest of the Brookville dome was determined. The number of wells lying within the area corresponding to each fraction was determined by counting.

3. For each of the mass fractions cycled, the formation pressure drop corresponding to delivery of a 2.1×10^6 lb/hr of air at the minimum reservoir pressure was calculated.

In this way, it was determined that 27 wells could provide a wellhead pressure sufficient to power the turbine with no allowance for pressure drop in the air collection manifold. A design based on 29 wells was employed to allow for the well and manifold losses. The characteristics of the initial air reservoir design are summarized in Table 7-6, and a schematic representation of the layout of this initial plant is provided by Figure 7-7.

The sequence of development steps corresponding to alternative three is:

1. Drill and complete 29 wells with air collection system designed for a maximum pressure of 420 psia.

2. At the same time, install one module of 150 MW generation capacity.

Table 7-6

CHARACTERISTICS OF THE 150 MW INITIAL AIR RESERVOIR DESIGN

Inventory of Stored Air (x 10^6 lb)	
Maximum	164
Weekly average	148
Minimum	133
Bottom Hole Flowing Pressures on Charge (psia)	
Maximum	403
Weekly average	374
Minimum	347
Bottom Hole Flowing Pressures on Discharge (psia)	
Maximum	283
Weekly average	240
Minimum	197
Water Front Pressures (psia)	
Maximum	348
Weekly Average	314
Minimum	282
Pressure at Aftercooler Outlet (psia)	
Maximum	420
Weekly average	380
Minimum	355
Pressure at Throttle Valve Before Regenerator (psia)	
Maximum	258
Weekly average	213
Minimum	170
Wells	
Number	29
Spacing (feet)	391
Depth (feet)	739

3. Connect the compressor train of the generating station to the 29 well system, and form the initial reservoir, over a period of 3 to 6 months. During this phase, it will be necessary to match the air accepting capacity of the field to the compressor by discarding the excess air flow through a throttling valve. An alternative is to employ a quarter flow compressor for this development. However, the use of the full compressor is less costly than installing the special compressor.

4. When the 29 well air reservoir is fully developed, commence cycling initially over the pressure ranges indicated in Table 5. To accommodate the expansion of the air reservoir an incremental pumping of 1.4 hr/wk will be required initially, growing to 5.8 hr/wk as the reservoir

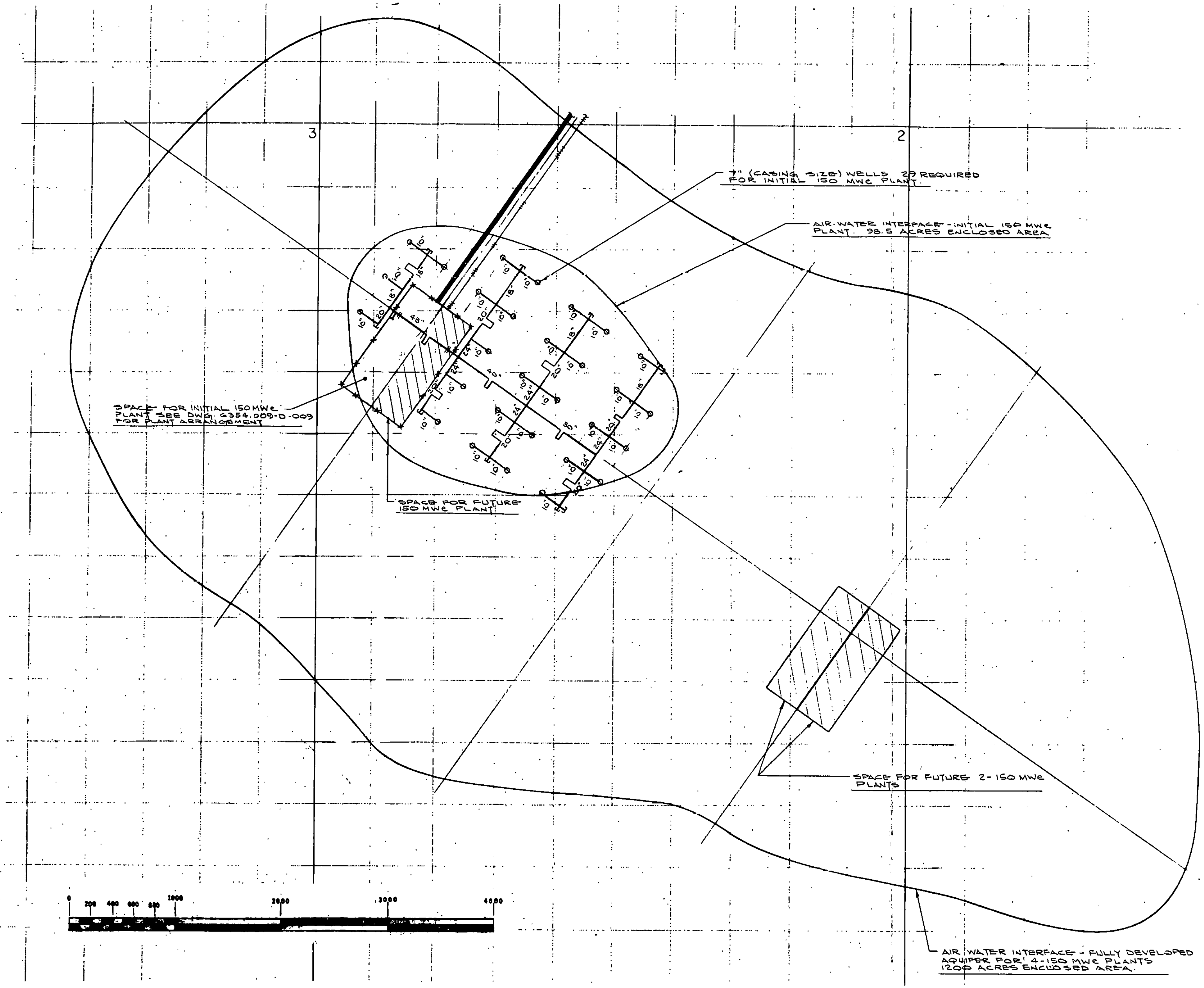

Figure 7-7. Layout of the Initial 150 MW Plant at the Brookville Site

near completion. As the reservoir develops, the fraction of stored air mass being cycled each week declines. As a consequence, the minimum pressure will increase during the reservoir development. This effect will be offset in part by the increase in reservoir temperature during development.

5. When the equilibrium reservoir size is reached, lower the pressure in the reservoir and cycle over the pressure ranges in Table 7-5. Install additional generating plants on this reservoir as required.

If additional generation capacity is not required during the development of the reservoir, a period of approximately five years would be needed to complete the development. Installation of further generating plants to the same reservoir would delay reaching the equilibrium reservoir size. An alternative would be to install additional capacity at the sites corresponding to the equilibrium plant design, and develop reservoirs at these plants following the sequence of steps 1-4 above. In the limit of parallel development of four generating plants, the equilibrium reservoir might be achieved in two years. Then the pressure would be lowered and the four plants would be operated in the equilibrium mode. The economics of these alternatives were evaluated in this study and are discussed in subsection 5 of this section. The following section describes the conceptual design of the plant, specifying the major subsystems.

7.4 CONCEPTUAL DESIGN OF THE BROOKVILLE STATION

GENERAL DESCRIPTION

The surface plant comprises two pairs of 150 MWe capacity generating/compression modules. A separate distribution manifold connects each 150 MWe plant to the aquifer. Each pair (total of 300 MWe capacity) has a common fuel storage and delivery system, and fire protection system. A single switchyard that is adjacent to one pair of 150 MWe units provides both control of combined plant output, and auxiliary load control, for the entire plant complex. A 345 kV line, nearly one mile long, connects the second 150 MWe unit pair to the central switchyard. The central control building provides remote control of each individual 150 MWe module, and houses sanitary facilities for an operating staff of up to sixteen people (three, 5 men shifts, plus day shift superintendent).

Each 150 MWe plant includes the necessary turbomachinery, heat exchangers, automatic valves, and auxiliaries to both compress and store air, or generate electrical energy. A pair of 150 MWe modules is arranged in a "mirror image" duplication scheme. Schematics of plant systems and flows are contained in Appendix J, "Brookville Station Drawings."

GAS TURBINE, MOTOR-GENERATOR AND MAIN COMPRESSOR

The gas turbine is a single shaft, 3,600 rpm machine. It is connected through a coupling at the inlet end of the turbine to the motor generator, which in turn is connected by a coupling to the low pressure compressor. A regenerative cycle is utilized to recover heat from the turbine exhaust gases and increase the effeciency of the turbine cycle. The turbine is enclosed within an acoustically-treated housing to reduce sound levels, and has hinged doors to facilitate maintenance.

Accessories Compartment

The accessories compartment contains the mechanical auxiliaries required to operate the turbine. These include: a lubrication system, hydraulic control system, starting motor and torque converter, turbine accessory gear, fuel system, turbine gage panel, motor control center for all base mounted motors, atomizing air system, turning gear, and high pressure CO_2 fire extinguisher system for the accessory and turbine compartments.

Control Compartment

The control compartment contains the equipment necessary to provide normal control and indication functions. Major components of the control package are the turbine Speedtronic control panel and generator panel.

Motor-Generator Compartment

The motor-generator compartment houses the motor-generator and its hydrogen cooling system. The motor-generator is a wye-connected, cylindrical-rotor synchronous machine. Clutches at both ends connect the turbine and the low pressure compressor to the generator. The motor-generator is rated at 14,400 V and 0.9 pf, and operates at 3600 rpm.

The components contained in the generator compartment are as follows:

- Synchronous generator-hydrogen cooled. The rotor is supported by two journal bearings. Resistance type temperature detectors are provided for the stator windings and hot and cold hydrogen gas temperatures. The saturable current transformers for the static excitation system, generator grounding transformer and neutral CT's are mounted on top of the generator in the SCT enclosure.

- Hydrogen cooling system. The generator is cooled by hydrogen which is circulated by shaft-mounted fans. The hydrogen coolers are mounted vertically in cooling towers at the four corners of the frame. The hydrogen system includes a gas control system, a seal oil control system, and a CO_2 purging system.

Exciter Compartment

The exciter compartment contains one static exciter nominally rated at 290 kW, 250 V, one air-cooled, three-phase, full-wave silicon diode rectifier assembly, three single-phase linear reactors, one shaft voltage suppressor, one automatic, solid state voltage regulator, and one auxiliary control and relay panel.

Switchgear Compartment

The switchgear compartment consists of one generator metal clad three-bay unit, nominally rated at 14.4 kV, three-phase, 60 hertz. It consists of a disconnect link for an auxiliary feeder, a generator circuit breaker, surge capacitors and lightning arrestors, potential and current transformers, and a customer power takeoff outgoing lead bus.

Closed-Cycle Cooling Compartment

The closed-cycle cooling system is designed to transfer rejected heat from the cooling water system to the ambient air. It is capable of maintaining proper cooling water temperature over the selected ambient temperature range. The cooling system also removes heat from all lube oil systems including the auxiliary compressor and the generator hydrogen cooling systems.

Battery Compartment

The battery compartment contains one 56 cell, 125 V, 290 Ah battery and one a-c/d-c battery charge.

COMPRESSED AIR STORAGE SYSTEM

Initial Manifold

The manifold for the initial plant connects 29 wells, spaced 391 feet on a square grid, to a common air inlet/discharge pipe. A main feed pipe coincides with the major axis of an elliptical-shaped fully developed aquifer enclosure. Branch feed pipes, perpendicular to the main feed connect two rows of wells via cross-feed pipes. All pipes are buried to a depth of six feet. A schematic of a typical buried manifold and wellhead is shown in Appendix J, Figure J-11. A 10 inch gate valve at each wellhead provides well-to-well flow balancing control, or complete isolation of a well for manifold repair. A 2-inch threaded nozzle, in each wellhead, provides easy pitot tube flow measurement. All piping is 35,000 psi minimum tensile yield strength carbon steel, field-fabricated and welded.

The final stage of development of the aquifer requires modification of the initial manifold. Manifolds for the two final (follow-on) plants include a portion of the initial manifold. Thus, the manifold branch pipes, and central main feeder pipe, terminate with blind flanges or flanged dished heads (only for the 48 inch diameter main feeder). A flanged section of pipe is also removed and refabricated to provide material for other parts of the manifold.

Pressure drop through the manifold is the primary design consideration, since the minimum turbomachinery air inlet pressure is 11.6 atm. The manifold pipe sizes selected account for the aquifer delivery pressure variations, and plant and equipment pressure losses.

Piping is sized for the maximum flow in a particular branch, for either the initial or follow-on manifolds. Pipe wall thickness is based upon the Gas Transmission Piping Code (ASA B31.1.8-1955) using a construction design factor for fringe areas around cities and towns.

Follow-on Plant Manifolds

The fully developed aquifer provides a storage volume covering 1200 acres, in a roughly elliptical-shaped, subterranean closure (Figure 7-6). The major axis of the elliptical closure is oriented in a northwest to southeast direction. The total closure area is divided into four (4) equal areas (approximately 300 acres for each 150 MWe plant) by boundaries perpendicular to the major axis. Each aquifer covers the full width of the elliptical closure.

A typical manifold for the fully developed aquifer connects 77 wells to a 150 MWe surface plant. The manifold main inlet pipe still coincides with the major axis of the elliptical-shaped, aquifer contour. Branch feedpipes are perpendicular to the main feeder line, and subsequently connect two rows of wells via cross feedpipes. A 6 inch gate valve at each wellhead provides both well-to-well flow balancing, and/or isolation of a well for manifold repair. A 2 inch threaded nozzle at each wellhead provides easy pitot-tube flow measurement. Pressure and temperature transducers at each branch feedpipe provide control room readout of plant operating characteristics.

Pressure drop through the manifold is also a primary design constraint. The aquifer delivery pressure fluctuates from 284 psia (early Monday) to 185 psia (late Friday). Also, the minimum inlet pressure to the turbomachinery regenerator inlet is 170 psia for optimum plant efficiency and performance. Pipe wall thickness is based upon the Gas Transmission Piping Code (ASA B31.1.8-1955) using a construction design factor for fringe areas around cities and towns.

AUXILIARY COMPRESSOR TRAIN AND HEAT REJECTION SYSTEM

The operating specifications for the initial 150 MWe plant, and the second, third and fourth (follow-on) plants differ as shown below:

	Initial Plant	Follow-on Plants
Operating air pressure	420 psi	284 psi
Operating air temperature	200 F	125 F
Airflow	2.1×10^6 lb/hr	2.1×10^6 lb/hr
Intercooling	2 stages plus chiller/heater	2 stages

The gas turbine, motor-generator and main axial compressor are identical for all plants. However, the auxiliary turbomachinery and intercooler specifications reflect the operating parameter differences between the initial and follow-on (second, third and fourth) plants.

Initial Plant

The initial plant requires an auxiliary compressor, two stages of intercooling, and an additional cooling cycle to further reduce the process air moisture content. Also, a separate compressor develops the initial aquifer storage volume (over a 98 area). This compressor is removed when the initial plant is operated in a compression/generation cycle.

The plant operates in one of three modes: compression, generation, or startup. During compression, air flows sequentially through the main axial compressor, first stage intercooler, auxiliary compressor, second stage cooler, chiller/heater and to the distribution manifold. During generation, air bypasses the auxiliary compressor and cooling machinery, and flows directly (from the manifold) to the gas turbine regenerator. Startup requires a bypass from the main axial compressor to the regenerator.

Auxiliary Compressor. The auxiliary compressor is an Elliot Model 60MB-4 constant speed, centrifugal machine, with a compression ratio of 2.6:1. The compressor and its 48,000 hp, constant speed induction motor, share a common reinforced concrete foundation, and are designed for outdoor operation.

During the final phases of aquifer development and plant construction, the initial plant is modified, and later operates at conditions identical to the follow-on plants. Therefore, the auxiliary compressor is modified to reduce the compression ratio to 1.9:1.

Intercoolers. The intercoolers (manufactured by McKenzie-Ris Manufacturing Company) are air-cooled, heat exchangers that remove the interstage heat of compression. Plant process air is manifolded through horizontal finned tubes. Forced draft fans direct ambient air over the tube surface, cooling the process air.

Each intercooler is an assembly of separate, self-contained bays, connected end-to-end, to provide the required heat transfer surface area. An individual bay includes two electric-motor-driven, forced draft fans. Both intercoolers are designed for outdoor operation, and will include tube heaters to prevent freezing during seasonally cold periods. The pertinent characteristics of the first and second stage intercoolers are shown below.

	First Stage (after main compressor)	Second Stage (after aux. compressor)
Temperature in	630 F	500 F
Temperature out	125 F	125 F
Heat Rejection load	280×10^6 Btu/hr	197×10^6 Btu/hr
No. of connected bays	20	8
No. of fans	40 at 29 hp each	16 at 30 hp each
Overall size	220 ft long x 36 ft wide	88 ft long x 36 ft wide
Type	Single pass	Double (U-tube) pass

A Burgess Model V-16 vane-type moisture separator removes condensed water from the process airstream, downstream of each intercooler. The extracted water (approx. 120 gpm) is pumped to the sewage system effluent discharge pipe leading to Elkhorn Creek.

Chiller/Heater. The initial plant develops the aquifer storage volume for the total 600 MWe generating capacity (approximately 1200 acre store area). Therefore, an additional moisture removal cycle is required, since even a small amount of water (liquid) carried into the aquifer will severely retard growth of the air/water interface.

The chiller/heater cools the plant process air to 60 F, removes the condensed water (approximately 15 gpm), and reheats the air to 200 F. Two shell and tube heat exchangers cool the air to 60 F. The first, connected to a Marley #8602 wet cooling tower, cools the process air to 100 F. The second heat exchanger cools the air to 60 F using a chilled water, 360-ton refrigeration unit manufactured by Carrier Corporation. A Marley #8611 wet cooling tower is the heat sink (condenser) for the refrigeration system.

Water circulation rates are 230 gpm and 1100 gpm respectively for the cooling towers. A water make-up system replaces the 75 gpm cooling tower evaporative losses. A third heat exchanger, at the auxiliary compressor outlet (prior to second stage intercooling) heats the process air to 150 F to 200 F. All heat exchangers, cooling towers, and the refrigeration unit are mounted on a reinforced concrete foundation.

Six electric-motor-operated sequencing valves control the plant operating mode, i.e., compression, generation or startup. These valves are a 36 inch, trunion-mounted ball valve, manufactured by Rockwell International. A pneumatic-cylinder-actuated automatic control valve, manufactured by the DeZurik Corporation, provides constant regenerator inlet pressure as the aquifer pressure fluctuates.

Follow-on Plants

The follow-on plants require an auxiliary compressor and two stages of intercooling. Air is delivered to the distribution manifold at 300 psi, 125 F.

The auxiliary compressor is an Elliot Model 60MB-4, constant speed centrifugal machine with a compression ratio of 1.9:1. The compressor and its 45,000 hp constant speed induction motor share a common reinforced concrete foundation.

The intercoolers are identical to the initial plant hardware, both in construction and heat rejection load. Similarly, moisture separators downstream of each intercooler remove 80 gpm and 40 gpm condensed water, respectively, and connect to the sewage system effluent discharge pipe. Since the moisture separator will continuously drain (by gravity), and will produce water only during compression, freezing protection (i.e., heating) during seasonal cold periods is not necessary.

The follow-on plants also operate in compression, generation or startup modes. During compression, air flows sequentially through the main compressor, first stage intercooler auxiliary compressor, second stage intercooler and to the distribution manifold. During generation air bypasses the auxiliary compressor and intercooler and flows directly (from the distribution manifold) to the gas turbine regenerator. Plant startup requires an auxiliary compressor from the main compressor to the regenerator. Six sequencing valves control plant operating mode. The valves are 36 inch, electric-motor-operated, trunion-mounted, pipeline ball valves. A pneumatic-cylinder-actuated automatic control valve provides constant regeneration inlet pressure during pressure fluctuations as the plant cycles.

Pressure and temperature transducers downstream of each compressor and each intercooler provide continuous control room monitoring of plant operating parameters, during compression and generation.

FUEL OIL SYSTEM

Provisions are made to store 6,000,000 gallons of distillate fuel oil for each two-plant cluster in a 124 foot diameter metal tank, 67 feet tall. This quantity of oil is sufficient for approximately 60 days when operating the plant on a 10 hour per day cycle, 5 days per week.

Fuel oil is received by rail tank car or highway tank trucks. A fuel unloading station, consisting of flexible hoses, pumps, pipe, and valves serve either rail tank cars of highway tank trucks separately, or simultaneously. Grounding and lightning protection devices and fire protection equipment are provided at the unloading station.

Fuel oil is pumped from the carrier to the storage tank and erected on a concrete pad within a diked area. The tank has a fixed roof and a floating suction. The earth's surface within the diked area provides an impervious barrier between any spilled oil and the surroundings. An earthen dike 5 feet high and 425 feet square surrounds the fuel storage tank and will contain 100 percent tank capacity in the unlikely event of a major spill. Area lighting, electrical, instrumentation, lightning and fire protection, and grounding are provided based on previous gas turbine plant experience.

Unloading Facilities

A fuel oil unloading station is located adjacent to the fuel storage tank and between a rail spur and a roadway. Unloading facilities include three 250 gpm, 50 psig pumps, flexible hoses for connecting the carrier to the pumps, and necessary valves and fittings to permit unloading either rail car or highway tanker separately or simultaneously. The three 4 x 6 centrifugal pumps are manifolded to a 6 inch Sch 40, welded joint, carbon steel pipe. Appropriate valving provides flexibility of operation. Unloaded fuel oil is filtered and metered with in-line devices. Fuel oil is discharged from the pumps through a manifold to a 6 inch buried, protective coated pipe and to the top of the fuel oil storage tank. Unloading pumps are pad mounted and grounded. The unloading area, except for the rail spur and the roadway, is surrounded by a concrete curb and is filled with crushed gravel. Prior to the placement of the gravel, the area surface is prepared so as to be impervious to any spilled oil. Area lighting, electrical, lightning and fire protection devices, and grounding meet all existing codes and previous gas turbine plant experience.

Storage Facilities

Storage for 6,000,000 gallons of fuel oil is provided by a field-erected, carbon steel tank. This tank is erected on an oiled sand base, contained by a reinforced concrete ring wall. No pilings are required at this site. An earthen dike 5 feet high and 425 feet square surrounds the 124 foot diameter by 67 foot tall storage tank, and contains 100 percent of the tank capacity in the unlikely event of a major spill. The surface of the dike-enclosed area provides an oil-impervious barrier to the surroundings. The tank is complete with caged roof, access ladder, vent, vacuum breaker, level indicator, fixed roof, floating suction and a steel sump pit. Manholes and nozzles are placed to transfer fuel into and out of the tank. Area electrical, lighting, lightning and fire protection devices, and grounding are provided as required by existing codes, API standards, and prior gas turbine plant experience.

Fuel Oil to Gas Turbines

The gas turbines in a two-plant cluster each burn approximately 96.5 gpm of fuel oil when fully loaded. An 8 x 6 foot centrifugal pump supplies fuel to the turbine fuel oil system. Two pumps are arranged in parallel to provide fuel system redundancy with isolation valves on each side of the pumps that permit pump maintenance during plant operation.

INSTRUMENTATION AND CONTROL

Main Power Station Building

The main power station building houses the auxiliary boiler room and water treatment area, control room, administration offices, machine shop, warehouse, locker and change rooms, and lunchroom. The building is a single story, steel-framed structure, 135 feet wide by 210 feet long and 20 feet high, supported on reinforced concrete column footings. The exterior walls are insulated metal siding, and the roof is metal decking covered with insulation and built-up roofing. The floor is a concrete slab on grade. Interior partitions are either concrete block or metal panel type; office areas are provided with suspended acoustical ceiling.

Instrumentation

The main power station building contains control equipment for all the gas turbines, generator, main compressor and auxiliaries for the four (total) 150 MWe plants. The equipment allows manual or automatic control, startup, acceleration, speed, temperature, fuel rate, and load following functions for the turbomachinery. Also, built-in systems trip the turbomachinery to protect against overspeed, overtemperature, vibration, flameout, and loss of load.

Pressure and temperature in monitoring systems for air pressure and temperature in the plant piping system and manifold provide readout on multiple station recorders located in the control room.

OTHER MECHANICAL SYSTEMS

Fire Protection System

Fire protection for the generating installation conforms with Underwriter's Laboratories, Factory Mutual, the American Water Works Association, the National Fire Protection Association, and applicable local codes. Fire protection is provided to transformers, turbine generators, fuel oil storage and unloading areas, control house, all enclosures, and to the plant yard.

The fire protection system includes an elevated water storage tank, fire pumps, a jockey pump, fire hydrants, hose houses, automatic sprinklers, and a 12 inch fire main completely encircling the facility. High pressure CO_2 bottles are strategically placed throughout the facility.

Water Supply and Fire Pumps. A 25 foot diameter by 20 foot high carbon steel elevated steel tank maintains a 65,000 gallon water supply for each two-plant cluster. Two 750 gpm fire pumps take suction from this tank and are automatically started when needed. These pumps are approved for fire protection service. A 25 to 50 gpm jockey pump is float-actuated to automatically maintain 100 to 110 psig on the system and prevent frequent cycling of the fire pumps.

The pump installation is provided with an outside hose header equipped with 6 to 8 hose valves and a flow meter for annual test purposes. Alarms, including pump running, power failure, and failure to start are provided. An alarm is also provided in the control room.

Yard Main and Hydrants. The yard main, consisting of steel pipe, completely encircles the plant. At 250 foot intervals along the entire length of the main, two-way hydrants controlled by individual curb box valves control two-way hydrants spaced at 250 foot intervals along the yard main. A hose gate valve is provided on each hydrant outlet. A standard hose house at each hydrant contains 25 feet of 2 1/2 inch woven-jacket lined fire hose, two spray nozzles, one axe, one bar, an emergency light, six spanners and two wrenches. Threaded hose fittings are identical for all existing equipment and that of the local public fire department. Post indicator valves are placed at strategic positions along the fire main for proper sectional control of the fire protection system.

Sprinkler Systems. A hydraulically balanced automatic water spray sprinkler system, utilizing directional solid-cone spray nozzles controlled by an approved deluge valve, with remote suitably located manual actuating stations, protects the main, station service, auxiliary and reserve transformers. A hydraulically balanced automatic water spray sprinkler system, utilizing non-solid-cone spray nozzles will protect all buildings or areas of combustible construction or having combustible occupancy. Alarms on each spray system are connected to an electric bell and annunciator in the control room.

Portable Fire Extinguishers and Inside Hose Connections. One inch hose connections, with 50 feet of 1 1/2 inch woven-jacket lined fire hose and adjustable spray nozzle are provided in the turbine-generator-compressor building spaced approximately at 100 foot intervals.

Fire extinguishers are provided throughout the facility in accordance with National Fire Protection Association regulations. Dry chemical and/or CO_2 bottles are also provided in certain specific areas.

A closed head CO_2 sprinkler protects the cable room, relay room and cable tray runs.

Special Protection. Fire and smoke detection systems connected to electric bells and annunciator in the Control Room, are provided in the motor control centers, switchgear room, battery room and control room areas.

Turbine Generators. The turbomachinery fire protection system includes a high pressure (turbine generator vendor-supplied) carbon dioxide, automatic single-zone fire protection system with nozzles in each compartment.

The supply system and a release mechanism are located in the accessory compartments. Initiation of the system trips the unit and provides an alarm on the annunciator, the trip ventilation fans and the close ventilation openings.

The fire protection system meets the requirements of NFPA #12 (a non-combustible atmosphere, within one minute or less). Good housekeeping, constant surveillance, and personnel alertness complete the fire protection at this facility.

Sanitary Sewage Facilities

An onsite aerobic digestion type package sewage treatment system is provided. The system is comprised of an aeration chamber, clarifier, aerobic digester and hypochlorinator enclosed in a 1/4 inch prefabricated steel plate tank and associated piping and foundation pad. The effluent is discharged into Elkhorn Creek.

Plant Compressed Air System

The service air system has two compressors and one receiver. It supplies air to the plant pneumatic valve operators, the plant machine shop, and other miscellaneous services.

Exterior or Yard Lighting

Electrical lighting provides sufficient illumination in each exterior plant area, during normal conditions. The system includes operating area lighting with equipment in the plant perimeter, illumination in conjunction with the plant security system and roadway lighting for normal plant traffic.

All building exteriors are illuminated by bracket-mounted mercury vapor lights that provide a minimum of five foot-candles at all active entrances and one foot-candle for the building surroundings. A similar scheme illuminates the fuel oil storage tank, except that 20 foot-candles of illumination are provided in the area of the tank unloading pumps and valves for operation and maintenance. Railway/highway tanker unloading areas are illuminated by pole-mounted mercury vapor floodlights that provide an average of 20 foot-candles over the entire area.

Pole mounted mercury vapor lamps spaced at 150 foot intervals, will maintain an average illumination level of 1/2 foot-candle along the perimeter fence. At active vehicle and pedestrian entrances, pole-mounted mercury vapor lamps maintain an average area illumination level of five foot-candles.

Pole-mounted lights at the intersection of all roadways maintain an average level of illumination of 1/2 foot-candle. Also, light from building exteriors, storage areas, unloading areas and plant entrances provide sufficient roadway illumination.

7.5 ECONOMIC AND TECHNICAL CHARACTERISTICS OF THE BROOKVILLE STATION

PERFORMANCE

The estimated output of the power turbine is 150 MW when operated at the normal base load firing temperature of 1985 F. Figure 7-8 shows the part load output as a function of the turbine inlet temperature. In a normal gas turbine which operates with a fixed air flow rate, the turbine inlet pressure reduces proportionately with the square root of the turbine inlet temperature (°R). However, in the compressed air storage mode, the turbine flow and inlet pressure can be varied independently of the firing temperature. Thus, provided adequate pressure is available in the storage cavity, when a greater power output is required, the turbine inlet pressure can be increased and an approximately proportional increase in power will be obtained.

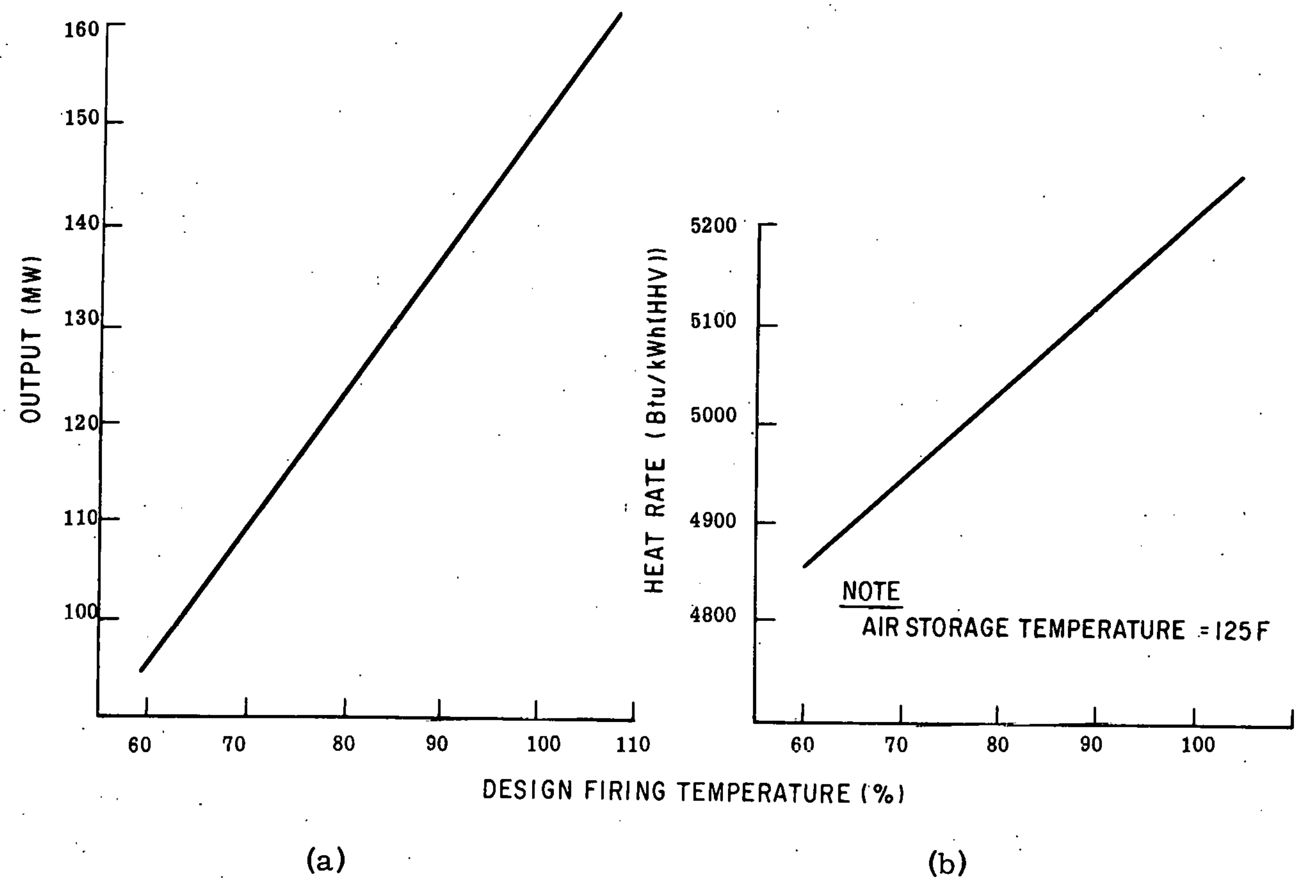

Figure 7-8. Brookville CAES Plant Performance

The estimated heat rate of the power turbine when operated at design firing temperature of 1985 F and with an air storage temperature of 125 F is 5252 Btu/kWh (HHV). When operated in a CAES plant, the variation of heat rate with firing temperature reverses the normal gas turbine characteristic, which is to decrease heat rate with increase in firing temperature. As shown in Figure 7-8, in the CAES mode the heat rate will decrease as the firing temperature is decreased. Although the turbine performance will be unaffected by ambient air temperature differences, the temperature of the air leaving the aquifer is expected to change slowly with the time. This will cause a change in the plant heat rate, but not in the plant power output. Figure 7-9 shows the effect of the heat rate of the temperature of the air leaving the aquifer.

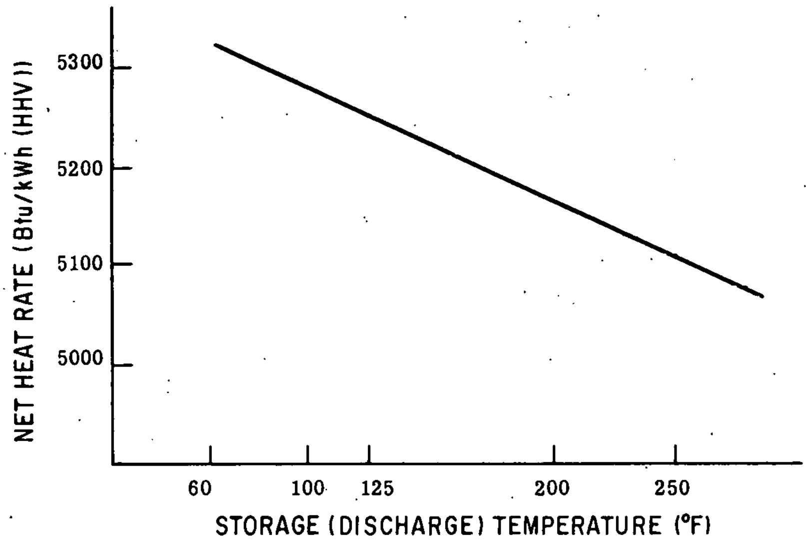

Figure 7-9. Effect of Air Storage Temperature on Heat Rate

The estimated power required to charge the aquifer is shown in Figure 7-10. During initial operation of the plant, when the air reservoir is still expanding, a compressor discharge pressure of 420 psia is estimated to be necessary. This will require 126 MW of compression power per turbine unit. Ultimately when the air reservoir is fully developed, the compressor discharge pressure will be reduced to 290 psia requiring 112 MW per turbine unit.

ECONOMIC EVALUATION

Several alternative schedules for the development of the Brookville site are possible. The rate at which the reservoir is expanded to the equilibrium size, the needs of the utility for meeting its peak demand with its own generation or by purchasing power from another utility, and the constraints on the availability of capital to the utility are important determinants in formulating these alternatives. Two CAES alternatives, described in detail in subsection 7-3, were selected for evaluation in this study. Two other alternatives available to the utility currently are to provide 600 MW of generation expansion in simple cycle or regenerative cycle gas turbines. To put all of these on the same basis, the present worth, in 1975, of the stream of funds that must be expended over the period from 1975 to 1987 for utility to own and operate each plant is compared. The year 1987 was selected as the terminal year in the

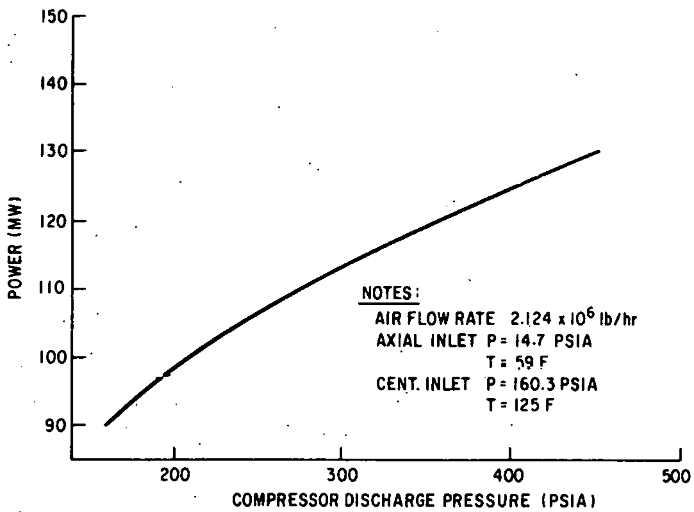

Figure 7-10. Air Compression Power as a Function of Compressor Discharge Pressure

study because, for the alternatives considered, this is the first year that each plant would be capable of generating 600 MW for 2000 hours without special expenses, credits or additional capital expenses. The procedure and assumptions employed to calculate the present worth of the annual revenue requirements (PWARR) are described in Appendix K, "Economic Evaluation of Alternatives."

The four alternatives considered were:

Alternative 1. Installation of a 150 MW CAES plant in 1981, followed by a 450 MW plant in 1986. During the period 1981-1985, the utility would purchase 90,000,000 MWh of energy at peak periods each year. The investments required by this alternative are detailed in Appendix I, "Estimate of Costs for 600 MW CAES Plant," and summarized in Table 7-7. The performance characteristics described above were used to calculate operating costs.

Alternative 2. Installation of a 600 MW CAES plant in 1981. Initial operation of the plant would be at a compressor discharge pressure of 420 psia, and this would be lowered to 290 psia after the reservoir expansion is complete. The costs summarized in Table 7-7 and Appendix I are adjusted to take into account costs associated with the pressure change as described in Appendix K.

Alternative 3. Installation of a 600 MW simple cycle gas turbine plant in 1981. The costs and schedules for installation of this plant are based on current commercial conditions. A heat rate of 11,300 Btu/kWh (HHV) was used to calculate the fuel costs for this alternative.

Alternative 4. Installation of a 600 MW regenerative cycle gas turbine plant in 1981. The costs and schedules for installation are based on current commercial conditions. A heat rate of 10,200 Btu/kWh (HHV) was used to calculate the fuel costs.

Table 7-7

SUMMARY OF COST ESTIMATES
FOR 600 MW CAES PLANT ALTERNATIVES

	Alternative 1		Alternative 2
	Initial 150 MW ($000)	Final 450 MW ($000)	($000)
Yardwork	1,751	649	2,400
Central control building	800	-	800
Fuel oil system	1,011	1,089	2,100
Gas turbine generator complex	15,765	45,649	63,054
Accessory electric equipment	1,337	1,633	2,970
345 kV switchyard	1,542	1,943	3,485
Miscellaneous equipment	148	112	260
Compressed air piping	2,562	8,615	18,969
Well construction and Land	1,758	14,078	15,836
Engineering and supervision	6,000	3,000	9,000
Contingency	3,285	4,325	6,396
Energy Costs for Reservoir	2,552	447	13,680
TOTAL	38,511	81,540	138,950
Generation Plant Cost ($/kW)	256.7	181.2	231.6

The PWARR's of the four alternatives are summarized in Table 7-8, and the 1981 investment per KW and 1987 sent-out costs are compared in Table 7-9. The sensitivity of the conclusions to the assumptions made regarding the price of oil is apparent. With respect to the two CAES alternatives and

Table 7-8

PRESENT WORTH OF ANNUAL REVENUE REQUIREMENTS

CAES Fixed Charge Rate (%)	15.66	15.66	15.66	15.66	18.00
1981 Fuel Cost ($/MBtu)	2.42	2.70	3.31	3.55	2.70
Alternative 1	179,553	182,267	184,136	191,715	188,215
Alternative 2	174,942	181,034	187,888	201,614	193,579
Alternative 3	160,589	173,692	188,465	217,998	184,701
Alternative 4	168,103	179,929	191,284	220,003	196,171

the simple cycle turbine expansion, a 1981 fuel cost of approximately $3.00/MBtu corresponds to near equivalency of the PWARR's. At lower fuel costs, gas turbine expansion is favored. This conclusion is not significantly affected by employing an 18 percent fixed charge rate in the analysis. A clear cut decision between Alternatives 1 and 2 cannot be made without further, more detailed analyses of the projected costs of purchased power. On the basis of 1987 sent-out costs, the two alternatives are very nearly equivalent.

Table 7-9

COMPARISON OF INITIAL CAPITAL INVESTMENT AND 1987 SENT-OUT COSTS OF ALTERNATIVES

Alternative	Initial Capital Investment 1981 ($/kW)	1987 Fuel Cost ($/MBtu)		
		3.24	3.62	5.04
		1987 Sent-Out Costs (mills/kWh)		
1	354.9	54.0	56.0	63.5
2	274.0	53.9	55.8	63.3
3	153.3	50.1	54.3	70.3
4	226.0	51.6	55.5	69.9

Section 8

DESIGN AND DEVELOPMENT PROGRAM FOR A CAES PLANT EMPLOYING A WATER COMPENSATED, EXCAVATED CAVERN

8.1 INTRODUCTION

A potential site for a conventionally mined, water compensated compressed air storage plant has been identified by a utility in Maryland near Washington, D. C. The general area of interest, near Sykesville, Maryland, is indicated in Figure 8-1. A limited conceptual design of an air storage facility at this site was carried out to test the conclusions reached in the assessment phase of this study. The power rating, generation time and maximum storage pressure was specified as the same as those prevailing at the Brookville site so that the conceptual design of the Brookville surface plant might be used with only minor modification.

The utility provided basic geological data which has been supplemented, as indicated in the following subsections, to complete the design. This data suggests that the host formation at the selected site is a massive unstratified granitic formation of metamorphic origin, extending from the surface to depths in excess of 4, 000 feet. More recent data from the Maryland Geologic Survey indicates that the Sykesville formation is not a granite, but is "a heterogeneous group of pebble and boulder bearing arenaceous to pelitic metamorphic rocks." The variable formation structure indicated by its heterogeneous characteristics suggests that a rather intensive exploration program may be required prior to actual specific site selection.

The basic disagreement as to what the host formation actually is makes one somewhat apprehensive as to the suitability of the selected site. As far as can be determined, neither detailed geologic mapping nor exploratory drilling and formation testing have been completed within the area of interest. This lack of factual geologic data for the selected site can greatly influence the conceptual estimated cost for this program, possibly to an order of magnitude. It also places greater emphasis to the need for a specific detailed site exploration program.

8.2 CHARACTERISTICS OF THE SYKESVILLE SITE

PHYSICAL CHARACTERISTICS

The site selected encompasses an area approximately 3 miles wide by 25 miles long extending in a northerly direction from Wheaton to Eldersburg, Maryland. This site is contained within Carroll, Howard and Montgomery Counties, Maryland and is underlain by the Sykesville formation of early Paleozoic time. The entire area of interest lies within the Piedmont Province,

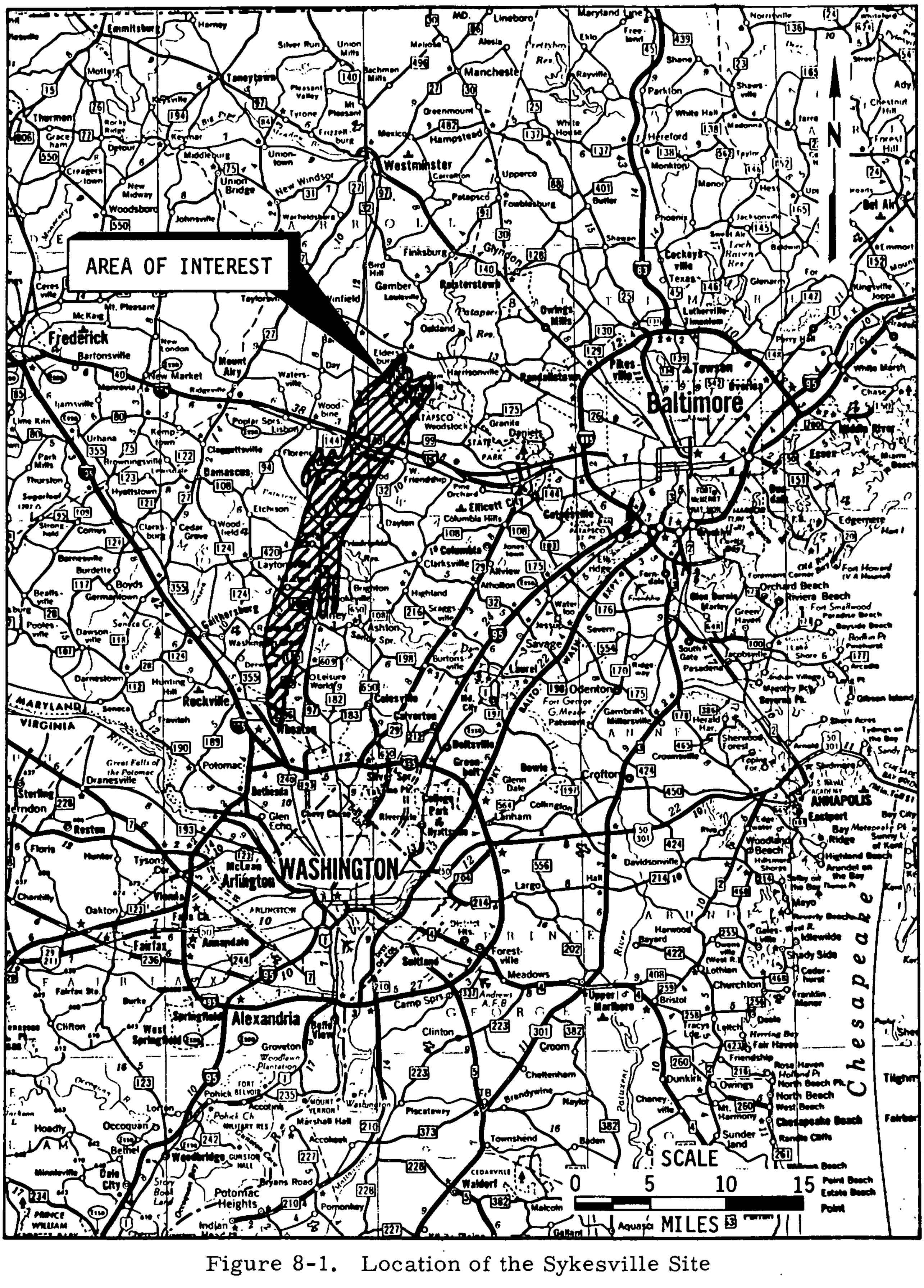

Figure 8-1. Location of the Sykesville Site

a plain formed at the eastern foot of the Appalachian Mountains. The topography consists of low, rolling hills on an eastward slope with stream drainage flowing southeastward into Chesapeake Bay from more or less parallel drainage basins. The Patuxent and Patapsco Rivers, along with numerous small streams and creeks, flow across the site toward the bay.

The area is underlain by crystalline rocks of pre-Cambrian or early Paleozoic age. The rocks consist chiefly of schist, phyllite and gneiss with small amounts of migmatite, granite, gabbro, marble and dike-like intrusives of granite pegmatite and diabase. The area is covered with a mantle of soil and weathered rock. A 30 to 50-foot mantle of soil and weathered rock overlies the Sykesville formation. The lower portion of the weathered zone consists of residual boulders embedded in partly decomposed and disintegrated rock. The local drillers refer to the top of the weathered section as "sand and gravel," to the lower weathered zone as "boulders" and to the bedrock gneiss as "hard rock." Since the surface is loosely consolidated and furnishes the majority of fresh water in the area, all surface holding ponds must be lined to prevent contamination of the fresh water supply aquifer.

THE SYKESVILLE FORMATION

The formation considered for the host for an air storage cavern is now mapped as a part of the Boulder formation, but for this report it will be referred to as the Sykesville formation. The Sykesville formation was originally reported by Stose and Stose (Ref. 11) and others as a gray to dark greenish-gray biotite quartz monzonite with a pronounced gneissic structure produced by a parallel arrangement of the biotite.

"The intrusive is well-shown at many places along the contact. The bordering country rock for some distance from the massive granite contains stringers and lenses of granite which have been twisted and kneaded with the sedimentary rock. The granite has penetrated the Peters Creek formation in the form of lit-par-lit injection and in stringers and dikes. Near the contact the granite contains inclusions of country rock, both large and small, the largest observed being 6 feet across. The inclusions are garnetiferous biotite schist and quartzite. The contact rock contains abundant large garnets which are chloritized in many places. Knots of quartz up to 1 1/2 inches in diameter are abundant in the granite near the contact. The quartz knots are elongated bodies that resemble pebbles" (Ref. 11).

Later studies (Refs. 4, 6, 7) have revealed that the Sykesville formation is not a granite, but instead is a thin bedded to massive, pebble and boulder-bearing arenaceous to pelitic metamorphic rock. Its appearance varies; typically it resembles medium-grained, garnet-oligoclase-muscovite-quartz gneiss, but locally it is an intensely foliated gneiss or schist (Ref. 4). Another variation is a fine-grained, nearly massive rock that resembles dark impure quartzite. In the field these variations are broadly gradational into one another.

This massive unstratified appearance of the Sykesville is one of its most distinctive characteristics. Inclusions found in the matrix, previously felt to be evidence of an igneous origin, are now thought to be remnants of the Wissahickon formation admixed into the Sykesville by slumping.

Mineralogically the Sykesville rocks are uniform with 85 to 90 percent of their composition being quartz, plagioclase and muscovite. Biotite, chlorite, epidote, magnetite and garnet make up the remainder of their composition. The rocks have a relict clastic texture, modified to varying degrees by deformation and recrystallization. The Sykesville can be considered anisotropic in nature. The field relations, textures, mineralogy and chemical composition of the Sykesville formation indicates a probable sedimentary origin (Ref. 7-8).

The Sykesville formation is thought to be a lenticular, thick pile of submarine slide material, intertonguing with the Wissahickon formation along its top, bottom and front. In Howard County, and in the northern part of Montgomery County, the Sykesville belt is approximately 3 miles wide and bounded on both sides by stratified schists dipping 60 degrees to 90 degrees west. Its apparent stratigraphic thickness here is about 15,000 feet, but the amount of tectonic distortion is unknown. The Sykesville formation is an unsorted transported sediment; a mixture of mud, silt, sand, pebbles, cobbles and boulders. It lacks stratification or bedding. Also, the slabby large inclusions stand at all angles to one another, thus indicating a rapid "dumping" rather than a slow accumulation of material. All of these suggest a slide or slump origin, especially if the following criteria described and found in the Sykesville by Cloos (Ref. 7) are considered:

- Hook-shaped, curled and rolled-up fragments, evidently remnants of disrupted slump overfolds.

- Quartz pebbles embedded in pelitic schist and metasiltstone, suggesting that the pebbles were pressed into the fragments while they were still soft.

- Long, thin, angular slabs, fragments of competent beds that were pulled apart.

- Fragments with intensely contorted internal laminations, suggesting deformation of soft beds before they were pulled apart.

- Indistinct, blurred contacts between fragments and host showing that the fragment was soft and had partly mixed with the matrix.

In a personal communication, Dr. William Crowley of the Maryland Geological Survey indicated that no faults had been mapped in the area and that little if any work had been done on joint patterns, fracture patterns and their spacings.

Water production from the Sykesville formation appears to be limited. According to Dingman (Ref. 9), 34 wells were reported in the Sykesville of Howard and Montgomery Counties prior to 1954. Eleven of these reported an average depth of 63 feet with an average yield of 9 gpm. In Carroll County, Meyer (Ref. 10) reported 18 wells in the Sykesville, 16 of which reported an average depth of 125 feet with an average yield of 23 gpm. Of these 16 wells in Carroll County, two wells located at Springfield State Hospital at Sykesville are 505 feet and 550 feet deep with yields of 22.5-60 gpm. Since these wells are near the northern extremity of the formation, and tend to indicate some type of fracture structure, it is felt that this area is probably not suited to storage. If these two deep wells are excluded, the average depth of the remaining 14 wells becomes 63 feet with a yield of 17 gpm. This bears out the verbal confirmation obtained from Dr. William Crowley of the Maryland Geological Survey that water production from the Sykesville would be very limited and the large majority of that production would come from the overburden-bedrock contact zone.

Since the recording of earthquakes began in the area, until 1973, only the three shocks described in Table 8-1 were recorded. The area is listed as being in an intensity zone of 1, an area in which only minor damage is expected.

Table 8-1

LOCAL SEISMICITY RECORDINGS IN THE SYKESVILLE AREA (REF. 8)

Date	Locality	North Latitude (degrees)	West Longitude (degrees)	Intensity (Mod. Mercalli)
April 24, 1758	Annapolis, Md.	38.9	76.5	
March 11, 1883	Harford Co., Md.	39.5	76.4	IV-V
March 12, 1883	Harford Co., Md.	39.5	76.4	IV-V

ROCK MECHANICS DESIGN

The design of any compressed air facility utilizing underground space for the storage of air under pressure must be predicated upon sound rock mechanics principles if adequate safety requirements are to be maintained. For the purposes of this analysis, a specific site has been selected in a granitic rock mass and it has been assumed that the required cavern space would be excavated using room and pillar methods. The approach to designing such caverns is described in Appendix D, "Rock Mechanic Design." The main object of this analysis is to determine the depth, extraction ratio, pillar size, volume, and aerial extent of a cavern and the diameter of the required water compensation shaft to satisfy a specific set of assumptions for an air storage facility.

The equations utilized in the rock mechanics analysis have been adapted from A. H. Wilson (Ref. D-2). It has been assumed that the load imposed upon a pillar consists of the weight of the overburden halfway to adjacent pillars plus the weight of one-half the height of the pillar. The combination of these loads form the tributary area load or total load on the pillar. It is assumed that the point of maximum stress occurs at the midpoint of the pillar and that the rock is competent and homogeneous.

The determination of the ability of a pillar to support the load imposed upon it is based upon the concept of a pillar core. In this concept it is theorized that the load imposed upon a pillar is carried by a central core which is completely surrounded and constrained by rock which has already passed its yield point and undergone some movement towards the drift. The constraint given to the central core by this "yield zone" can increase its strength considerably. Beginning at the edge of the pillar, the stress gradually increases from zero till a peak abutment stress is reached. This peak represents the failure stress of the rock under the loading conditions. Beyond this peak the rock stress has not reached the yield point and the rock will behave more or less elastically. The value of the peak abutment stress is a function of the internal angle of friction, the rock mass cohesion, the average confining stress, and the loading conditions. The distance into the pillar at which the abutment stress is reached is a function of the frictional resistance developed in the "yield zone." Assuming the peak abutment stress to be the maximum allowable stress in the pillar, the stress distribution envelope for a square, wide pillar (a wide pillar being one whose width is greater than twice the distance into the pillar to the peak abutment stress) becomes a truncated pyramid. With this assumption, the loading capacity of the pillar can be found by calculating the volume under the stress distribution envelope.

The following symbols are defined for this analysis:

- C = Allowable compressive strength of rock, psi
- d = Diameter of water compensation shaft, feet
- D = Depth to floor of cavern, feet
- G_f = Facility generating capacity, MW
- H = Overburden thickness, feet
- L = Pillar design strength, psi
- m = Pillar height, feet
- P = Pillar side dimension, feet
- P_c = Cavern storage pressure, psia
- Q = Volume flow rate of water in compensation shaft, cfs
- R = Percent extraction

t_d = Cavern discharge time, hours
ν = Velocity of water in compensation shaft, fps
V = Cavern volume, ft^3
V_e = Estimated cavern volume, ft^3
X = Cavern side dimension, feet
X_e = Estimated cavern side dimension, feet
Z = Drift width, feet
γ = Unit weight of rock, lb/ft^3
ρ_ω = Unit weight of water, lb/ft^3

Although a specific site has been selected, some of the specific rock properties required for design are, as yet, unknown. In order to proceed with the analysis, it is necessary to make the following assumptions concerning rock properties and safety factors. These values are based on engineer's experience rather than on specific information regarding the site.

C = 25,000 psi with a 2.5 safety factor so L = 10,000 psi
γ = 170 lb/ft^3
ρ_ω = 62.4 lb/ft^3
ν = 12 fps
m = 25 feet
$R \leq 50\%$

The following are the given conditions which must be met by the cavern:

G_f = 600 MW
t_d = 10 hours
P_c = 20 atm + 11.16375 psi + 0.43265 m = 315.90 psia at m = 25
V_e = 59,805,000 ft^3

Assuming that stability exists at the point where the load imposed on a pillar is less than or equal to the loading capacity of the pillar, the following equations have been developed:

$$R = 1 - \{P/(P+Z)\}^2 \quad (1)$$

$$P = (1-R) \{1+(1/1-R)^{1/2}\} Z/R \quad (2)$$

$$D_{max} = (1-R) \{144L/\gamma - m/2\} + m \quad (3)$$

$$D_{min} = 144P_c/P_\omega \quad (4)$$

$$X_e = (V_e/mR)^{1/2} \quad (5)$$

$$X = \{(X_e-Z)/(P+Z)\uparrow\}(P+Z) + Z \quad (6)$$

$$V = mRX^2 \quad (7)$$

$$Q = V/3600t_d = \pi \nu d^2/4 \quad (8)$$

$$d = (V/900\pi\nu t_d)^{1/2} \quad (9)$$

The following calculations were performed to determine the required data:

Let D_{max} = D_{min} and solve for R from

$\frac{}{2}$ = $1 - \{(144P_c - m\rho_\omega)/\rho_\omega\}\, 2\gamma/(288L - m\gamma)$ =

$1 - 0.083234 = 91.6766\%$

as R ≤ 50%, use R = 50%

From D_{min} = $144P_c/\rho_\omega$, D = 729.00 feet

From H = D - m, H = 704.00 feet

From P = $(1-R)\{1+(1/1-R)^{1/2}\}\, Z/R$, $P = (1+2^{1/2})Z$ = (2.414213562374) Z feet

From X_e = $(V_e/mR)^{1/2}$, X_e = 2187.327136027 feet

From X = $\{(X_e - Z)/(P+Z)\uparrow\}(P+Z) + Z$,

Z	$P_{theo.}$	P_{used}	X	Rank
20	48.284	48.5	2212.50	3
21	50.698	51	2253	16
22	53.113	53.5	2211.50	2
23	55.527	56	2235	7
24	57.941	58	2238	9
25	60.355	60.5	2248	12
26	62.770	63	2251	15
27	65.184	65.5	2247	10
28	67.598	68	2236	8
29	70.012	70.5	2218	4
30	72.426	72.5	2285	18
31	74.841	75	2257	17
32	77.255	77.5	2222	5
33	79.669	80	2293	19
34	82.083	82.5	2247.50	11
35	84.497	84.5	2305.50	20
36	86.912	87	2250	14
37	89.326	89.5	2187.50	1
38	91.740	92	2248	13
39	94.154	94.5	2308.5	21
40	96.568	97	2232	6

Use Z = 37.0 feet, P = 89.5 feet, and X = 2187.50 feet

From V = mRX^2, V = 59,814,453.1250 ft^3

From d = $(V/900\pi\nu t_d)^{1/2}$, d = 13.2775 feet

The results of these calculations for a room and pillar configuration in granite rock, with a square arrangement with 18 rooms and 17 pillars on a side, are summarized in Table 8-2.

Table 8-2

PARAMETERS OF THE ROOM AND PILLAR CAVERN
AT THE SYKESVILLE SITE

Allowable compressive strength of rock	25.000	psi
Diameter of water compensation shaft	13.28	ft
Depth to floor of cavern	729.0	ft
Overburden thickness	704.0	ft
Pillar height	25.0	ft
Pillar side dimension	89.5	ft
Volume flow rate of water in compensation shaft	1662	cfs
Velocity of water in compensation shaft	12.0	cfs
Cavern volume	598.1	million ft^3
Cavern side dimension	2187.5	ft
Drift width	37.0	ft

A compressed air storage facility used in conjunction with a conventionally mined underground chamber in the Sykesville metamorphic rocks will require a detailed exploration prior to construction. A proposed exploration program for this location is described in more detail later in this report. The room and pillar system of mining was selected for the conceptual design of this underground compressed air cavern. Figure 8-2 shows a typical conventially mined room and pillar conceptual compressed air storage cavern. The room and pillar mining method is a proven system for underground excavation having overall favorable economic considerations. The Rock Mechanics section of this report defines the assumed parameters for the cavern and, should these change appreciably, it will be reflected in the overall cost/yd^3 of excavated material. It must be remembered that because rock conditions can and do vary considerably over relative short distances, these changes can and will directly affect the overall project cost. For this study we have assumed that no costly ground support problems will be encountered. In the design of a water compensated cavern, great care must be taken to prevent erosion of the main pillar support and the distribution tunnel system. The water distribution system should be sized to not exceed a maximum flow

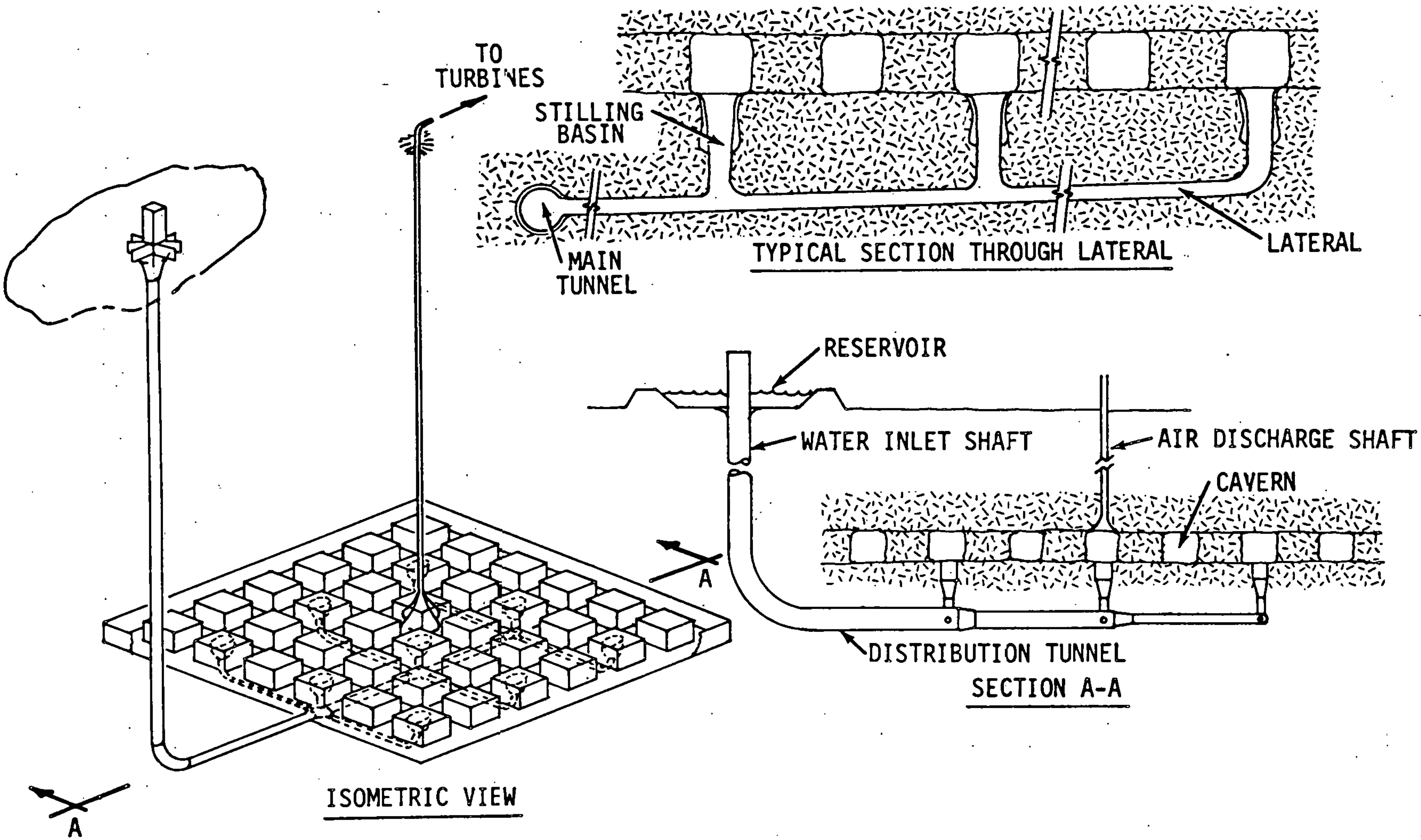

Figure 8-2. Conceptual Design of Room and Pillar Compressed Air Storage Cavern

velocity of 20 fps, as recommended by the U.S. Bureau of Reclamation, to prevent pillar and floor erosion.

8.3 SITE EXPLORATION PROGRAM

The program begins with a literature search to obtain available data on the Sykesville formation. In conjunction with this search, inquiries should also be made to various federal, state and local agencies. Upon completion of the information search, an area is selected for detailed field mapping. At the same time, remote sensing and geophysical testing can be conducted.

When this work is completed and the site deemed acceptable for a compressed air storage cavern, a pattern of holes can be laid out similar to that in Figure 8-3, and the exploration drilling phase commenced. It is recommended that a drilling order similar to that indicated on Figure 8-3 be followed, so as to define any possible detrimental structure with a minimum of drilling.

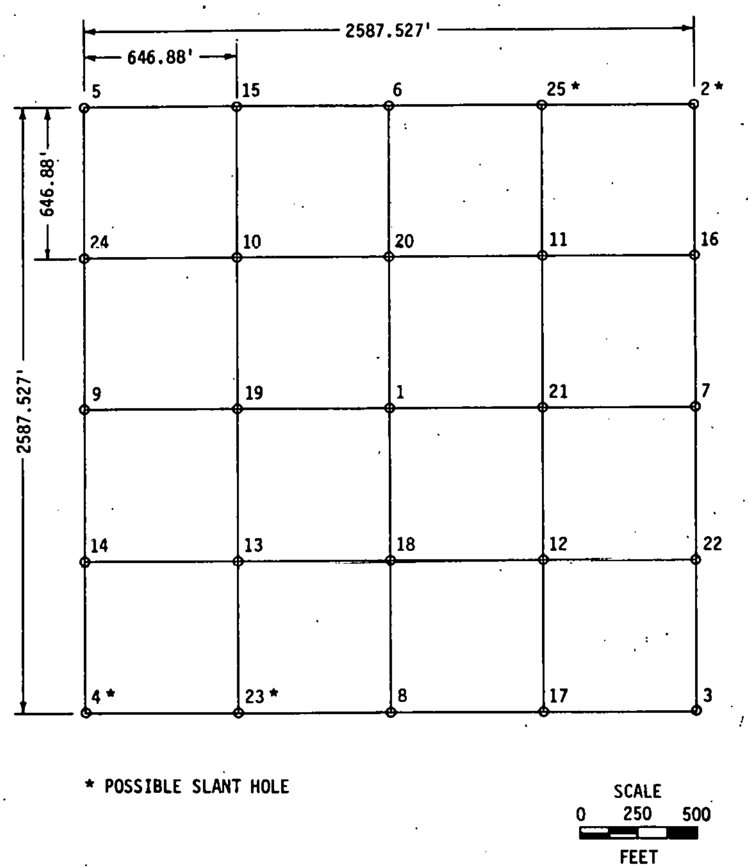

Figure 8-3. Spacing of Drill Holes for Exploration at the Sykesville Site

In order to define the joint and fracture patterns, it is recommended that several holes be drilled on a slant so as to cut across any joints or fracture patterns (Figure 8-3) that may exist. These slant holes should be drilled in pairs to cut across both sets of joints at a given location. All slant holes must be drilled away from the cavern. Those drill holes laid out for the cavern area itself must be located so as to penetrate the cavern interval through a pillar.

The typical sequence for each drill hole is as follows:

- Prepare drill site and mobilize drill rig onto it.
- Drill overburden and set surface casing.
- Diamond core hole to 1,000 feet. Due to the metamorphic nature of the Sykesville formation, full hole coring is recommended.
- As drilling progresses, select and ship samples of core to the laboratory for analysis.
- Pressure test each hole to determine the in situ permeability and porosity of rock.
- On completion of testing, examine the results obtained and move to the next site as required.

While each hole is being drilled, core samples should be taken at selected intervals and shipped to the laboratory for testing. The following suite of tests are recommended for each core sample:

1. Creep
2. Permeability*
3. Dynamic elastic constants
4. Static elastic constants
5. Triaxial shear strength
6. Triaxial compressive strength*
7. Uniaxial flexural strength
8. Uniaxial tensile strength
9. Uniaxial shear strength
10. Uniaxial compressive strength
11. Weathering resistance*
12. Abrasion resistance
13. Hardness
14. Porosity*
15. Specific gravity*

Those items with the asterisk (*) are considered as the minimum that are absolutely necessary.

Upon completion of all field studies, drilling, testing and laboratory testing, a report is compiled outlining the results of the test and core program.

The initial test should be confined to the number one test hole. If all test data seems positive in analysis, testing should commence on succeeding holes. If the test data at any time during the program indicates that the site is unsuitable, then that site should be abandoned and a new one selected.

The estimated effort for completion of the geological feasibility study from project initiation to issuance of the final report is six man-years. A breakdown of this estimate is as follows:

• Literature search, field mapping and geophysical studies	14 man-months
• Drilling, testing programs	54 man-months
• Final report	4 man-months
	72 man-months = 6 man-years

8.4 ECONOMIC AND TECHNICAL CHARACTERISTICS OF THE SYKESVILLE STATION

The cost estimate summary for the cavern construction of a 600 MW 10-hour duty cycle cavern, water-compensated compressed air storage facility is shown in Table 8-3. These figures indicate that the cavern-only costs for energy storage are $12.46/kWh.

One factor which has considerable impact on the economics of a conventional mined cavern is that of waste rock disposal. It has been suggested that this commodity is an economic asset to the concept and should be so credited. This report, however, concludes that the mine-run waste rock is a project liability and is therefore a definite part of the overall cost of the cavern. Mine-run waste rock is generally not crushed and screened to the various sizes, which would be required to produce a saleable product. The addition of a crushing, washing and screening plant would be necessary to produce a saleable product. Additional capital investment and operational personnel would be required through the life of the mining operation. This plant would bc required to process approximately 1, 000, 000 yds^3 per year during the active mining period. Assuming that the necessary installed plant capacity exists, a market for this yearly volume of rock must be developed. This would require the operator to go into competition with other aggreate suppliers within the area. This type of operation would only put an additional operational burden on the project management. Experience has shown that the possibility of selling this material is very slight and the probability of giving it away not much better. It is therefore our opinion that the most feasible, economical and environmentally sound concept is to contract for this waste rock disposal.

Table 8.3

ESTIMATED ELEMENTS OF COST FOR PREPARING THE AIR STORAGE CAVERN AT THE SYKESVILLE SITE

20 Atms (294 Psia) Compensated Cavern Construction Item	600 MW 10 Hour Cycle Unit	Unit Cost	Total Cost
Geologic mapping, research, etc.	1	$ 200, 000	$ 200, 000
Exploration drilling (feet)	25, 000	16	400, 000
Laboratory testing (per sample)	2, 500	150	375, 000
Formation testing (lump sum)	1	86, 000	86, 000
Land acquisition (per acre)	260	2, 500	650, 000
Site preparation (per acre)	10	2, 000	20, 000
Mined production shaft (per foot) 14 foot ID concrete lined	829	2, 865	2, 375, 000
Air outlet shaft (per foot) 36 inch ID cased	704	1, 030	725, 000
Mined volume (yd^3)	2, 292, 579	20	45, 852, 000
Waste rock disposal (yd^3)	2, 980, 353	2. 50	7, 451, 000
Surface reservoir (bbls)	11, 023, 000	0. 65	7, 165, 000
Small equip., hand tools & misc. % subtotal construction cost		15%	8, 720, 000
Time for construction (year)	8		
Insurance during construction % of construction cost/year	5	. 5%	729, 000
Total Cost			74, 748, 000

The plant design for the Sykesville Station should provide an output of 600 MW at the normal baseload firing temperature of 1985 F. The estimated heat rate for an air storage temperature of 125 F is 5252 Btu/kWh, and the compression power requirement will be 112.5 MW.

The cost elements for the complete Sykesville Station are summarized in Table 8-4. These costs may be compared with those in Table 7-7 for Alternative 2, the complete 600 MW plant, at the Brookville site. There are some significantly lower costs for certain elements of the Sykesville Station:

- Turbomachinery - The Sykesville booster compressor train goes to a maximum pressure of 316 psi while the Brookville compressor train must reach a maximum outlet pressure of 430 psi.

- 345 kV switchyard - The Brookville costs include those for a 345 kV transmission line connecting two 300 MW modules at the site. It is proposed that a single switchyard would serve the 600 MW Sykesville generation plant, with all four 150 MW turbine/generators located within a single module.
- Miscellaneous equipment - The Brookville costs include two trucks and some communications equipment required because of the large area covered by the plant.
- Compressed air piping - The Sykesville costs are for a single 48 inch line connecting the turbomachinery complex to the cavern, and for the piping to connect together the turbines and compressor trains.

Table 8-4

SUMMARY OF COST ESTIMATES
FOR 600 MW CAES PLANT: SYKESVILLE STATION

Description	Cost $000
Yardwork	2, 400
Central control building	800
Fuel oil system	2, 100
Gas turbine generator complex	60, 837
Accessory electric equipment	2, 970
345 kV switchyard	2, 740
Miscellaneous equipment	144
Compressed air piping	1, 600
Cavern construction and land	74, 748
Engineering and supervision	9, 000
Contingency	5, 071
Total	162, 410
Generation plant cost $/kW	270. 7

In addition, there is no cost in developing the Sykesville site equivalent to that of the energy costs for reservoir development at the Brookville site. However, these savings are more than offset by the cost of the cavern for the Sykesville Station with the result that the plant investment required is approximately $40/kW more than that required for the Brookville Station. The cost for the Sykesville Station is somewhat greater than one would estimate from the projected costs for the 12 and 40 atm plants in Section 5. This is due to the approximately 40 percent increase in balance of plant costs for the Sykesville Station as compared with the hypothetical plants of the assessment.

Because projections of fuel and offpeak power costs were not available for the utility potentially served by the Sykesville Station, an economic analysis at the level of detail of that of the Brookville Station was not carried out. A comparison of the cost of energy sent out from the CAES plant with that from a 600 MW S/C gas turbine installation was made. The investment required for the CAES plant is that summarized in Table 8-4. When escalation and interest during the eight years of construction is added to these costs, the total capital investment made by the first year of operation, assumed to be 1983, is $295,332,000. The corresponding investment required for a S/C gas turbine plant operating in 1983 is estimated to be $77,910,000.* The values of other quantities used in the evaluation are compiled in Table 8-5. The 1983 sent out cost for a 600 MW CAES plant at the Sykesville site is estimated to be 129.8 mills/kWh, which can be compared with 99.5 mills/kWh for the 600 MW S/C turbine plant. The 1983 fuel cost that corresponds to equivalent generation costs for the CAES and gas turbine plant is $5.49/MBtu.

Table 8-5

ASSUMPTIONS USED IN THE ECONOMIC EVALUATION
OF THE SYKESVILLE STATION

Annual escalation of capital costs	6%
Annual interest during construction[a]	10%
Fixed charge rates	
CAES plant	15.66%
S/C gas turbine plant	1-14.04%
1983 fuel cost[b]	$2.98/MBtu
Heat rates	
CAES plant	5252 Btu/kWh
S/C gas turbine plant	11300 Btu/kWh
1983 Charging power cost	$10.18/MWh
1983 Operating and maintenance cost	$2.20/MWh

a) The commitment schedule for the gas turbine plant described in Appendix K was used. The following commitment schedule for the CAES plant was used:

8 yr	3%	4 yr	25%
7	3	3	17
6	7	2	12
5	23	1	10

b) Corresponds to $2.70/MBtu in 1981 with 5 percent escalation.

*See Appendix K for the 1975 costs and commitment schedule employed to obtain this value.

8.5 SUMMARY

Because the specific properties of the rock, at depth, which would serve as the host formation for an air storage cavern at the Sykesville not known in detail, the cost estimate for construction of a cavern at this site is necessarily quite approximate. A 72 man-month exploration program would be needed to complete an analysis of the geological feasibility of the project. Based on estimates of the properties of the rock derived from published reports, a cost of $12.46/kWh for construction of a compensated cavern at the Sykesville site was derived. This cost may be reduced significantly if the constraint of nearly constant pressure (within ± 0.5 atm) at the turbine inlet is relieved, allowing a cavern with a height greater than 25 feet to be built. Adapting the cost estimates for the Brookville Station to the Sykesville site, a generation cost of $271/kW is obtained, in 1975 dollars. Because the site studies and construction are estimated to require a total of eight years, the annual revenue requirements for 1983 operation of a 600 MW CAES plant and a 600 MW S/C gas turbine plant were compared. The S/C gas turbine alternative is favored by 30 mills/kWh (1983 dollars) for "average" assumptions of fuel and charging energy costs. The cost of turbine fuel corresponding to equivalent revenue requirements for the two alternatives is $5.49/MBtu in 1983, substantially higher than current estimates of the probable range of petroleum derived fuel costs.

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Section 9

AREAS FOR FURTHER INVESTIGATION

9.1 INTRODUCTION

The approach that has been taken in defining areas and directions for further work is based on consideration of the following questions:

- What are the significant barriers to the immediate implementation of CAES by utilities?
- What technical effort might, if successful, substantially increase the long-term attractiveness of CAES to utilities?

A number of the potential barriers to the immediate implementation of CAES that are discussed in subsection 2-7 of this report will be resolved most efficiently by a phased program leading, if successful, to demonstration of each of the three principal methods for carrying out CAES. Certain actions, apart from such a program, also could enhance the rate and extent to which CAES is employed by utilities in the United States.

TECHNICAL FEASIBILITY

Compressed gas storage underground on the scale contemplated for a CAES system has been carried out only for seasonal leveling of the demand for natural gas, principally methane. Not only are the physical and chemical characteristics of methane different from those of air in such critical parameters as viscosity, water solubility, oxidizing properties and ability to support the growth of aerobic microorganisms, but the rate of injection and removal and the treatment of the gas immediately after leaving the underground store are quite different. A number of questions are raised by these considerations when one compares the experience obtained in natural gas storage with that to be expected in compressed air storage. There are two major categories of concerns: those arising from interactions of the air with the host formation and those arising from the interaction of any material carried out of the cavern with the expander train. These are discussed in subsections 9-2 and 9-3.

CAPITAL COSTS

The major uncertainty is the cost of the excavation of underground reservoirs. The ultimate resolution of this uncertainty will result from the bids received to prepare such a reservoir. However, two further lines of investigation that might result in the reduction of the estimated costs of the caverns are a study of the effect of cavern design, particularly height, on the cost and performance of a CAES plant using a compensated reservoir, and an assessment of the cost-benefit of bored caverns as CAES reservoirs. In particular, the state-of-the-art of the use of boring machines to excavate large caverns is quite young, and, if a sufficient incentive were identified, a timely opportunity to effect the development of this technology for CAES construction may exist.

TECHNOLOGY - SPECIFIC INSTITUTIONAL BARRIERS

A number of legal questions, particularly with respect to the use of aquifers, is raised by CAES. An investigation of these questions, particularly drawing on the experience of the natural gas storage industry, could be useful to accelerate utility implementation of aquifer storage. State by state analysis of the relevant state and local environmental statutes, and regulations and ordinances will be needed.

UTILITY PLANNING

Presently few utilities have incorporated the characteristics of CAES into their generation planning methodology. This is one aspect of the more general problem of developing appropriate analytical tools for utilities to develop generation costs for all the promising methods of utility energy storage.

GEOLOGICAL INFORMATION

By working with state geological agencies and with petroleum producing companies that have been active in a utilities service area, it may be possible to formulate much more precise appraisals of site availability than are now possible. A model study in one utility area to demonstrate how this might work could facilitate utilities undertaking this task.

FUEL AND CAPITAL AVAILABILITY

These are national problems that are receiving substantial attention already. The policy with respect to allocation of gas turbine fuel to utilities will have a substantial effect on the acceptance of the technology by utilities. The appropriate policy making institutions should be kept informed of the effects of their policy decisions on the application of CAES technology.

To increase the longer range attractiveness of CAES to utilities, programs to reduce capital costs and increase the efficiency of premium fuel usage are needed. New developments in turbomachinery that are discussed in subsections 9-4 and 9-5 could be instrumental in achieving both objectives. Because of the differences in performance characteristics of turbomachinery operating in the conventional gas turbine cycle and in the CAES cycle, developments that improve the efficiency and specific cost of the former do not necessarily benefit the latter. The development of a turbine system with a 40 atm inlet pressure capability is indicated as a desirable goal. An analysis of the relationship of specific output and efficiency to firing temperature indicates that the choice of optimum initial and reheat temperatures in a two-stage expansion train is substantially affected by the introduction of a recuperator in the cycle. Development of a single shaft compressor with suitable flow capacity with a pressure ratio capability of 16:1 to 20:1 is a realistically achievable interim goal. The probability of success in developing a 40:1 pressure ratio compressor with the necessary flow capacity, without intermediate speed changes and intercooling, is not considered to be very high.

Because the potential oil savings from widespread implementation of a combined air and thermal storage system are considerable, this system should be given careful consideration. The equipment required to carry out this cycle is so far beyond the present state of technology, that a detailed conceptual design study is required to estimate the capital and operating economics and to identify critical engineering problems and the necessary development programs.

9.2 BEHAVIOR OF UNDERGROUND STORAGE RESERVOIRS

With respect to compensated, conventional caverns, the only additional stresses imposed on a cavity serving as a compressed air store compared to those already serving as, for example, propane stores, is the daily temperature cycling that the rock must undergo as warm air and cool water alternate. This temperature cycling is capable of producing stresses in the rock surface exceeding the yield stress. When coupled to stresses already in the formation, their interaction could produce degradation of the cavern wall, opening previously existing fissures and leading to slumping or leakage (Ref. 2-13). Heating from 10 to 50 C results in compressive stresses which reach about 40 percent of the compressive strength of grouted granite. These are sufficiently large stresses that considerable degradation in the cavern walls might be expected depending on the initial surface conditions. Before proposing cycling over wider temperature ranges or at more rapid pressure loadings or unloadings, a careful site specific examination of the mechanics of the particular formation being considered may have to be conducted. The results of taking into account the differential thermal expansion of the various constituents of the rock should be considered in evaluating the range of effects of temperature cycling on crystalline rock.

A common phenomenon in many mines is air slacking, a term that is applied to the spalling of rock surfaces due to humidity variations. Air slacking may be anticipated in the operation of either compensated or uncompensated caverns. Thus it appears advisable to schedule periodic visual inspections of the cavern and anticipate that cleanup operations may be required to correct the effects of rock falls on flow losses in the cavern.

These phenomena do not appear to represent barrier problems to compressed air storage in compensated, conventionally mined caverns. Compensated solution mined caverns, from this viewpoint, represent even less of a problem because of the greater thermal conductivity of salt over, for example, granite, as long as the cavern operating pressure matches the formation pressure.

The question of the extent of the leakage to be expected from compressed air storage in various types of rocks needs more attention than has been given to it to date in the literature. In particular, the effect of temperature and pressure cycling on the leakage rate from excavated hard rock caverns appears to be a question of considerable importance to the economics of systems employing such caverns.

For uncompensated caverns, the effect of pressure cycling on the host formation could represent a limitation to the operation of a CAES system. The mechanical response of the host formation to cycling will depend to a considerable extent on the conditions prevailing at the site. A thorough on-site investigation will be necessary to determine the in situ rock properties required for design. The following properties should be determined prior to excavation:

- Magnitude and direction of virgin horizontal and vertical stresses
- Location and extent of jointing, faulting, and fracturing
- Internal angle of friction

In order to provide a sound basis for design, it is recommended that a qualified rock mechanics consultant be utilized to prepare and conduct a comprehensive program to investigate the mechanical behavior at the site. While generalizations regarding the mechanical response of host formations to temperature and pressure cycling may be uncertain at present, research results have been reported that are highly relevant to improving the reliability of such generalizations (Refs. 2-32, 2-64). For wide pressure variation in uncompensated granite caverns, the fatigue life of the cavern walls may be comparable to the lifetimes expected of the compressed air storage facility (Ref. 2-32). This experimental work should be extended to other rock types that may be suitable compressed air host formations. However, its translation to the actual performance of caverns will be complicated by the nature of the fissure and stress patterns in the formation at the particular site.

The results of investigations of the effects of temperature cycling in crystalline rocks have shown that the extent of damage does not increase after about three cycles, and the network of surface cracks does not coalesce to the extent that the surface crumbles (Ref. 2-65). If rock may be considered to be a representative ceramic material, then the number of cycles to which the rock is subjected may not be the important factor, but instead, the time spent at stresses above the critical level, and the humidity content of the atmosphere during the stress period may be crucial. Further experimental investigation of the interaction of thermal and pressure effects on the behavior of crystalline rocks should provide either increased assurance or early problem identification with regard to CAES in such rocks.

With respect to salt caverns, there has been considerable theoretical and experimental work concerned with the mechanical behavior of salt and of storage cavities in salt. In connection with studies of the disposal of radioactive wastes in salt caverns, creep laws for salt have been derived (Ref. 2-21), but these are not adequate to describe the pressure and temperature regime prevailing in compressed air storage. The stability of openings in salt has received attention and some success has been obtained in correlating field behavior with theory (Refs. 2-15, 2-19, 2-43). However, none of these descriptions appears to be directly applicable to predicting the effect of frequent temperature and pressure cycling on the closure rate of an opening in salt. Further theoretical work to guide field studies leading to a CAES system employing a cavern in salt appears to be needed.

With respect to CAES in aquifers, there are several areas where further work is indicated.

MODELING OF FLOW BEHAVIOR

The mathematical description of air and water flow in porous media that was used in designing the Brookville Station does not appear adequate for a detailed design study. For example, work already in progress elsewhere indicates that the steady state approximation on which the conceptual design calculations were based introduces an appreciable error into the calculated formation pressure losses. The existence of temperature and moisture gradients around each well bore was not taken into account and will surely modify the behavior of the reservoir compared to that calculated using the simple flow model. A more detailed treatment to describe the performance of aquifers should be carried out.

DRYING OUT OF CAPROCK

It has generally been thought that the ability of shale to act as a competent caprock is due to the presence of interstitial water. If hot, dry air is stored under such a caprock, it is important to know what the effects on caprock integrity will be.

POORLY CONSOLIDATED FORMATIONS

A possible concern is the effect of frequent cycling and high air flow rates on high permeability, poorly consolidated sandstone reservoir rocks. Experience of natural gas storage has shown evidence of particulate abrasion on casings under high delivery rate conditions. This concern will be resolvable only by laboratory and field testing of candidate host rocks.

GROUNDWATER ALTERATION

Particularly in the case of fresh water aquifers, it is important to assess the potential for contamination of the aquifer by introduction of such substances as lubricants from the compressor train, and possibly, aerobic bacteria, as well as the effect on water quality of oxidation and evaporation resulting from air storage.

OIL AND GAS RESERVOIRS

A detailed examination of a depleted reservoir to evaluate the interaction between stored compressed air and residual hydrocarbons is required. The experience of the petroleum industry in fire flooding should be examined. Some preliminary laboratory investigation is required of the interaction of bitumen impregnated reservoir rock with hot compressed air to observe either ignition or oxygen depletion.

9.3 CARRYOVER FROM UNDERGROUND STORAGE

The degree to which particulate matter, and especially alkali metal compounds are carried over from the underground storage to the expander train, will affect the extent of development effort needed to achieve the estimated system performance. Combustion turbine alloys are sensitive to very low concentrations of alkali metals if sulfur compounds are present in the fuel or air. Modern gas turbines utilize nickel and cobalt based superalloys for the turbine hot gas path components which must have high strength characteristics at high operating temperatures. Today's gas turbines operating within gas temperatures around 2000 F utilize cooled buckets that have skin temperatures in the order of 1500 to 1600 F. At these temperatures, the superalloys are highly susceptible to hot corrosion attacks resulting from condensation onto the buckets of compounds of sodium, potassium, lead, and vanadium which are ingested into the turbine with the fuel, air, and any injected steam or water.

To minimize the occurrence of hot corrosion attack and preserve the life of the hot turbine parts, it is necessary to limit the contaminants (Na, K, Pb, and V) to extremely low levels. The current General Electric heavy duty gas turbine fuel specification requires that the total sodium and potassium in the fuel be 1.0 ppm, total lead 1.0 ppm and total vanadium less than 0.5 ppm.

Since the turbine airflow is in the order of 40 to 50 times the fuel flow, the possible contaminants in the air must be limited to much lower levels.

The following formula can be used to calculate the contaminants in the fuel, air, and water equivalent to the contaminants in the fuel only:

$$\left(\frac{A}{F}\right) X_A + \left(\frac{W}{F}\right) X_W + X_F = \text{equivalent contaminants in fuel alone}$$

where:

$\frac{A}{F}$ = air to fuel mass flow ratio

$\frac{W}{F}$ = water to fuel mass flow ratio

X_F = contaminant conc. (weight) in fuel ppm

X_A = contaminant conc. (weight) in air ppm

X_W = contaminant conc. (weight) in water ppm

For example, if we do not wish to exceed the 1.0 ppm limit for sodium and potassium, we can calculate the maximum allowable in the air for an assumed level of 0.5 ppm in the fuel with zero water injection and an air to fuel mass flow ratio of 50:1.

$$X_A = \frac{1.0 - 0.5}{50} = 0.01 \text{ ppm (Na + K in air)}$$

Note that this is only an example; different levels of contaminants in the fuel and different air/fuel ratios will affect the allowable levels in the air. The General Electric Gas Turbine Products Division has established a "referral limit" for the combined amount of Na + K + Pb + V to be 0.005 ppm. This limit would cause an insignificant contribution to the overall contaminants and have a minor effect on the life of the hot gas path parts.

To achieve these low levels in highly contaminated environments, several kinds of gas cleanup equipment are used, depending on the size and nature of the particles to be removed. No experimental evidence is accessible to assess the extent or particle characteristics of the carryover from aquifers, salt caverns,or mined caverns. As noted in Section 2, some experimental work has been carried out in connection with the design of the NWK plant to assess the extent of carryover from a salt cavern, but the details have not been described. However, additional attention to the quantitative aspects of NaCl carryover from salt caverns appears justified. One possible approach might be to analyze the NaCl pickup by the glycol absorbers used to strip moisture from the gas stored in the southeast Michigan gas storage plant. An analogous approach might be employed with other gas storage plants to determine the carryover of harmful materials such as sulfur and vanadium. This is a problem area requiring experimental as well as theoretical analysis, and may perhaps be most efficiently carried out as part of a preliminary design study at a specific site.

Once the information is available, it should prove possible to design and build air treatment apparatus to control the problems, if any exist. For example, demisters now is use are capable of lowering the salt content of gas turbine inlet air to 4×10^{-3} ppm under severe marine salt spray conditions.

No equipment is presently available that will operate with gas turbines and sustain the substantial pressure gradient required in a compressed air plant. The pressure losses and capital costs associated with air cleanup equipment will depend on the characteristics of any carryover, and have not been factored into the estimates of cycle performance or capital costs in this study. Their effect on the system performance will be to increase the pumping power required without effecting the combustion turbine heat rate, so that oil saving will be independent of the severity of carryover.

Other materials may be carried from an underground gas store that might harm a CAES system expander train. For example, large particles are occasionally swept out with the gas delivered from the Leyden Mine, a gas storage facility near Denver, Colorado, that employs an abandoned coal mine as a storage reservoir. With poorly consolidated or silty-sandstone aquifers, particulate carryover might represent a problem after the formation had been dried by repeated cycling. The use of filters is indicated, once the problem is recognized. Until sufficient experience is obtained with the operation of CAES systems, the installation of probes for sampling for particulates and alkali metals in the airstream coming from underground is indicated.

A third class of materials that might be swept from an air store and interact with components of the expander train consists of volatile materials such as methane, ammonia, and H_2S that are sometimes found in certain rock formations. The case of methane was alluded to previously. Because of the danger of generating an explosive methane/air mixture, abandoned natural gas fields may be precluded from use for compressed air storage. Furthermore, because of the potential cross leakage between methane and compressed air stored in a different formation on the same structure, the joint operation of a CAES system and a natural gas storage facility at the same location may not be practical. Ammonia and H_2S which are sometimes associated in aquifers (Ref. 2-43), represent potential environmental problems because of SO_x and NO_x emission. If present in sufficiently high concentrations, they may also produce hydrogen embrittlement of some alloys used in turbines. If high H_2S and ammonia concentrations are encountered at an otherwise favorable storage site, then materials experience obtained from geothermal turbine performance should be applied to determine if there is an economically feasible way to employ the site.

A somewhat different aspect of carryover may result from the dissolution of air in water in a compensated storage cavern. There has been discussion of the serious consequences of permitting the water to become saturated with air at pressure during the period that the cavern is charged, and possible methods have been described to control the phenomenon (the "champagne effect") if long standing of the charged cavern and a substantial contact surface between air and water are essential (Refs. 2-50, 2-58). This problem should be avoidable through appropriate cavern design, which will substantially reduce the contact air between air and water in the fully charged cavern. For example, in the design employed in this assessment, the air/water contact surface in the fully charged cavern is less than one quarter of that in the half-charged cavern.

9.4 DEVELOPMENT OF FUEL-FIRED CAES SYSTEMS

The compressor, turbine, and combustion systems currently available for use in CAES systems have been designed and developed as integrated components of gas turbines. The performance characteristics of these components operating in the gas turbine may differ somewhat from the performance characteristics operating in the CAES mode. In conventional gas turbines, improvements in thermal efficiency and specific output, which relate to machine size and cost, have been achieved by the steady increase in the turbine firing temperature and overall pressure ratio. Figure 9-1 shows a typical set of performance curves giving the relationship between specific output, pressure ratio and firing temperature, and thermal efficiency for a regenerative cycle gas turbine.

However, in a CAES system the gas turbine, when not required to drive its own compressor, has an entirely different set of characteristics as shown on Figure 9-2. As can be seen, the thermal efficiency of the turbine decreases with increasing firing temperature while the specific output increases. Since the specific capital cost ($/kW) will be heavily influenced by the specific output (kW hr/lb) and the operating cost will be a direct function of the thermal efficiency or heat rate, developments of the turbine systems to improve CAES

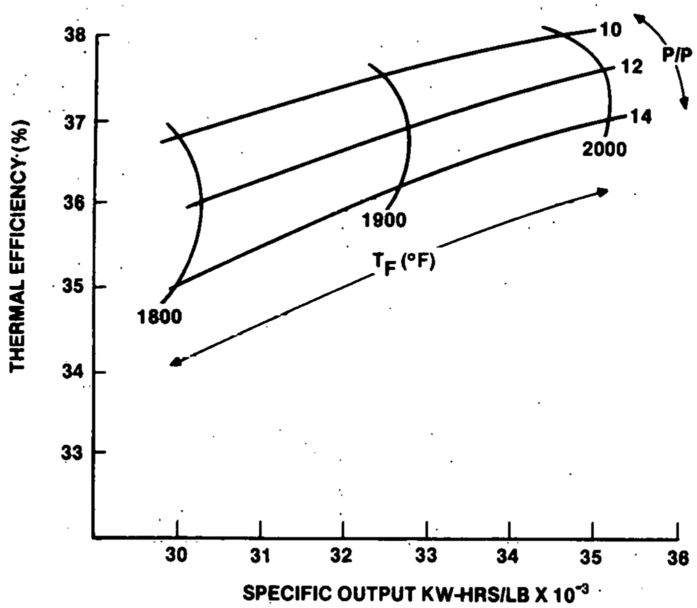

Figure 9-1. Typical Regenerative Cycle Gas Turbine Performance Characteristic

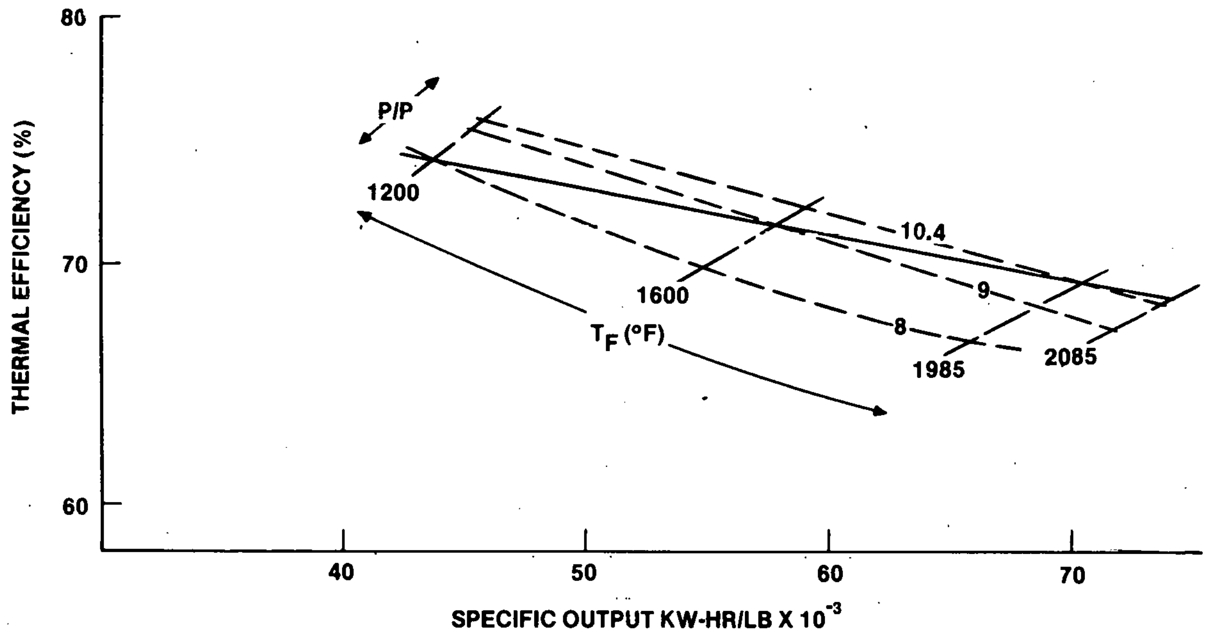

Figure 9-2. CAES Performance Characteristic

cost and efficiency will require careful tradeoffs between the capital gains made by improving specific output versus the possible operating cost losses produced by a lower efficiency.

An important shortcoming of the available turbine systems when they are used for CAES is their relatively low inlet pressure capability compared to the air storage pressure. Since it appears that storage system pressure in the range of 45 to 80 atm are a realistic probability, a turbine inlet pressure capability of approximately 40 atm would appear to be a desirable goal. However, it should be carefully noted that increasing the turbine expansion ratio from 10:1 to 40:1 in all cases results in a higher specific output, but a higher thermal efficiency does not always result.

There are two possible approaches to the development of turbines with approximately 40:1 expansion ratio:

- The first approach would be to design a totally new optimized turbine and combustion system. Such a turbine could be either a single turbine and combustor or a reheat arrangement with the reheat pressure and temperature established for the optimum output and efficiency. The development of a totally new gas turbine design would undoubtedly be the most costly and longest alternative.
- The second, more practical and lower cost approach, would be similar to that adopted by Brown Boveri Co. in their design of the Huntorf gas turbine. In this case, a high pressure topping turbine

based on an existing steam turbine design has been integrated with an existing gas turbine design. The development of a new gas path is eliminated and the major development required is for the high pressure combustion system.

However, before selecting a system for development, a detailed economic tradeoff study of the alternatives should be considered. Figure 9-3 shows the performance of a number of alternative cycles with overall expansion ratios of approximately 40:1. Shown on the figure is the specific output and efficiency for expansion cycles incorporating high pressure combustion systems and high pressure combustion systems plus a conventional low pressure exhaust heat recuperator. The performance is shown for a range of high pressure turbine inlet temperatures and two values (1515 F and 1985 F) of low pressure turbine temperature. The performance of the Huntorf Plant which operates with T_1 = 1000 F and T_2 = 1515 F is spotted on the graph. It can be seen that in nonrecuperated cycles, turbine output and efficiency is maximized when the initial and reheat temperature are made as closely equal and as high as possible, as in the case of the Brown Boveri system. The addition of a low pressure exhaust heat recuperator, however, not only increases the overall thermal efficiency but changes the characteristic to one of increasing specific output with decreasing efficiency. Thus, a cycle with lower initial and reheat temperatures, which increases the thermal efficiency with some loss in output, may be the economic optimum. As noted earlier, all of these systems have specific outputs greater than the base system, but not all have lower heat rates.

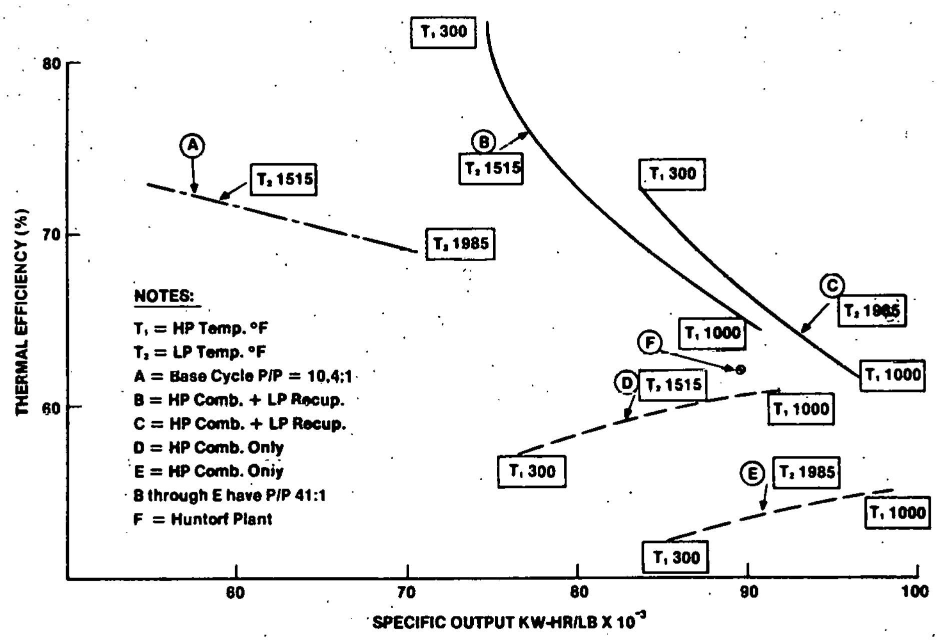

Figure 9-3. High Pressure Expansion Cycles

An alternative to the use of the high pressure combustion system is to sue an exhaust heat recuperator ahead of the high pressure turbine. The performance of such a system is shown on curve F (Figure 9-3) for a range of LP turbine inlet temperatures. The design of the heat exchanger for such service will require some development, however, since it must be capable of operating at relatively high pressure - 40 atm, with gas temperatures of approximately 1000 F. The daily cycling operation of the CAES system imposes the additional risk of thermal fatigue on the necessarily thicker metal or ceramic sections of the heat exchanger.

Thus, the selection of an expansion cycle that will result in an optimum combination of plant cost and operating costs, i.e., lowest mills/kWh, and identification of the necessary development programs can only be done when a detailed economic evaluation of the many possible alternatives has been completed.

The effect of compressor technology developments will be primarily on CAES system costs since adiabatic efficiency levels are already in the upper 80 percent range and are not forecast to improve significantly. The most important development necessary is the increase in pressure ratio capability on a single compressor shaft since this would simplify and lower the cost of the overall plant design.

Current compressors with suitable single shaft designs and of a flow capacity useful to utility size CAES systems have a pressure ratio capability of approximately 12:1. Extension of this pressure ratio capability to a range of 16:1 - 20:1 is thought to be realistically achievable. Such a pressure ratio level is still likely to be too low for use without a booster compressor in a CAES system. However, this development is still a worthwhile interim goal, because in addition to the plant simplification and cost reduction it would provide, it would also be a valuable adjunct to the major national development program for high temperature turbine technology.

The extension of the 20:1 pressure ratio up to the 40:1 or higher pressure ratio requirements of CAES systems, without intermediate speed changes and intercooling, will require considerable study and research; based on the current knowledge of high pressure compressors, the probability of success is not considered to be very high. Because of the difficulties of starting very high pressure ratio compressors without experiencing damaging surge and pulsations, it is likely that the complexity of such high pressure ratio compressors might offset the cost reductions resulting from fewer compressor bodies. In addition, raising the pressure ratio without intercooling will result in an increase of the power necessary to drive the compressors, which will impose a cost penalty offsetting the cost reductions from elimination of intercoolers. Thus the need for and development cost of very high pressure ratio compressors must be carefully weighed against the total cost benefits that will actually be gained.

9.5 DEVELOPMENT OF UNFIRED CAES SYSTEMS

The potential oil savings that might be realized by the development and widespread use of a Combined Air and Thermal Storage System (CATS) dictates that such a system should be given careful consideration. A preliminary consideration of this system has indicated that a number of major questions must be answered before a reasonable assessment of the system potential and development needs can be made. The most important requirement is that a detailed conceptual design of such a system be made.

Apart from the obvious concerns about the ability to design and construct compressors to deliver 100 atm of air without intercooling and a multiplicity of shafts, there are some other considerations that might be of major significance. At pressures of more than 100 atm and temperatures of approximately 1500 F (815 C), the strength of materials capability becomes very limited. High temperature materials such as NiCr alloys are necessary which are not only very expensive but often difficult to fabricate into the necessary components which makes this a costly process. Because of the thick walls necessary to contain the pressure at allowable stress levels, thermal fatigue behavior under the daily cycling operation of the plant is a concern. Considerable experience gained in the operation of steam turbine plants has shown that rapid temperature cycling of thick walled pressure vessels, pipe and turbine shells can cause cracking and failure. This experience must be carefully considered when designing a plant with intended twice daily cycling.

The heat storage subsystem and the necessary heat exchangers to transfer the heat to and from the air pose a number of technical challenges - not the least of which is the volume of storage material necessary to store the heat. In addition to the fundamental questions on the selection of the heat storage material, there will be similar strength of materials considerations regarding the containment and insulation of the material. A major factor in the design of the turbine will be the ability of the heat storage material to deliver all the stored heat at an essentially constant temperature. If the heat can only be recovered with a constantly decaying temperature, the turbine will suffer a corresponding decay in output, or require a special design that could accommodate the expected variance. An alternative approach would be to include an auxiliary combustion system to smooth the temperature. Such an auxiliary combustion system would also be useful for system starting, since apart from a variable frequency electric start, no other means of starting the compressors would be available.

Conceptual answers to these and many other considerations, leading to a preliminary conceptual plant design are required before a realistic cost estimate and economic appraisal is possible. Since the potential advantages of this system are significant, it is recommended that a separate study of this system be undertaken to prepare a technical and economic assessment such that the need for and specific development of such programs can be identified. The specific objectives of such a study might be:

1. To define the range of operating parameters of practical interest: flow rates, pressures, temperatures.
2. To prepare preliminary conceptual design of turbomachinery, heat storage and air storage systems in sufficient detail to perform 3 and 4.
3. To estimate capital and operating economics and determine if there is sufficient incentive to pursue development.
4. To identify critical engineering problems and necessary development programs.

After a multidisciplinary team with knowledge and experience in the areas of compressor design, turbine design, heat exchangers, strength and processing of materials, and heat storage can be assembled, it is estimated that a useful assessment could be completed in about six months with a 4 to 5 man-year total effort.

9.6 SITE INVESTIGATIONS

As has been noted frequently in this report, the nature of the specific site selected for CAES and the system needs of the utility with access to the site will be the determining factors in the technical and economic feasibility of any CAES project. This was most clearly shown in carrying out the conceptual design of the Brookville, and to a lesser extent, Sykesville Stations. Many of the efforts described in subsections 9-2 and 9-3 also can be most effectively carried out as part of a site investigation. Thus, it is clear that the most important area for further work is that of carrying out preliminary designs of CAES plants for specific sites which, coupled with appropriate experimental programs at the sites, could, if successful, lead to pilot and demonstration CAES programs.

APPENDIXES

Appendix A

MAJOR LITHOLOGIC ENVIRONMENTS

The rock types (lithologies) considered for air storage may be broadly grouped as igneous intrusive, metamorphic, and sedimentary, on the basis of their forms of origin. The intrusive rocks include granites, granodiorites, diorites, syenites, gabbros, and similar crystalline intrusive lithologies. Because of their widespread occurrence, metamorphic rocks such as gneisses and schists are probable host formations for compressed air storage. Metamorphic rocks are essentially sedimentary or igneous and have been altered by heat and pressure to become foliated and partially to totally crystalline. The sedimentary rock types include two depositional groups: marine deposits and terrestrial deposits. The marine sediments include the carbonates (e.g., limestones and dolomites) and evaporites (e.g., salt and anhydrite). The terrestrial deposits can be described as thin-bedded to laminated sedimentary rocks having predominantly clay-size grains (shales) and sandstones composed of sand-size grains cemented by calcite, silica, or other cementing agents.

A.1 IGNEOUS INTRUSIVE LITHOLOGIES

The igneous intrusive rocks can be generally characterized as having excellent mechanical strength and low primary (original) permeability and porosity. There are several large outcroppings of these rocks in the United States, as shown in Figure 3-17 of this report.

Igneous intrusive rocks form as large masses of molten material, which intrude the near-surface strata but do not break through the crust before cooling and solidifying. Because the hardening process is normally quite slow, the rock develops as crystalline intergrowths, tightly bound by high, confining pressure and internal geometric structure. Very little void space is created or remains during solidification, and primary porosity is typically less than 2 percent. Primary permeability of these rocks is generally zero; secondary permeability resulting from cooling (i.e., joints) is a common feature of intrusive rocks. By the use of careful exploration techniques it has been possible to delineate areas of low primary and secondary porosity and permeability. These areas are well suited to mined cavern storage of low-pressure gas (LPG) and other hydrocarbon products, and it is believed these same techniques can be used to find suitable sites for compressed air storage caverns.

The high mechanical strength of most intrusive rocks makes possible the construction of very stable mined openings. Unconfined compressive strength values typically range from 7,000 to 35,000 psi, and average between 15,000 and 20,000 psi in those intrusive rocks where storage caverns have been constructed. Tensile strength is much less than compressive strength in all lithologies. In the granitic intrusive rocks the tensile strength values typically range from about 400 to 700 psi considerably lower than their compressive strength values but still higher than most other naturally occurring rocks.

Table A-1 presents strength values for several rock samples tested under laboratory conditions. These values are representative of the ranges that can be expected for each intrusive rock classification.

A.2 METAMORPHIC LITHOLOGIES

The metamorphic rocks include both gneissic and schistose types, plus selected marble and slate occurrences. As a group, the metamorphic rocks range from igneous to sedimentary in appearance. The gneissic rock types are generally coarse, crystalline and banded, with a fairly high degree of differential mineralization. The schists are fine-to-coarse crystalline rocks with a preponderance of micaceous minerals in subparallel alignment. The strength of these foliated rocks is highly variable from place to place in a given formation. Careful evaluation is required to locate suitable mining sites. Gneisses and schists suitable for compressed air storage will have physical characteristics much like igneous intrusive rocks.

Marble is a metamorphic rock composed largely of calcite and/or dolomite and has been commonly quarried for building stone. It is a highly competent rock, is readily mined, and might prove to be very satisfactory for compressed air storage at selected sites. Similarly, slate is a very fine-grained metamorphic rock, having fissile bedding and excellent cleavage, which might prove to be a suitable host for compressed air storage. However, since both marble and slate have been mined primarily for building stone from near-surface deposits, it seems unlikely that preexisting caverns, either slate or marble, will be found at depths suitable for compressed air storage.

A.3 SEDIMENTARY LITHOLOGIES

The sedimentary rocks that will be considered include limestone, dolomite, shale, rock salt and related evaporites, and sandstone. All of the sedimentary rock types were deposited as layered beds in large depositional basins. The limestone, dolomite, and evaporites are largely marine deposits; shale and standstone are both terrestrial and/or shallow marine deposits. The large depositional basins where sedimentary rocks predominate are outlined in Figure 3-20.

Limestone strata have many physical characteristics that make them favorable for mined caverns. Limestone deposits are widely distributed throughout the United States; many deposits are thick, massive, and competent, providing for very stable mined openings. Limestones are subject to water dissolution, particularly along fractures and joints; this process, however, is not rapid. Hundreds of years are required to develop small, open water channels and many thousands of years to build extensive caverns.

In addition to new mines, many large limestone mines exist in several areas of the country, and it is conceivable that some of these mines might be found suitable for conversion to compressed air storage. The majority

Table A-1

STRENGTH VALUES FOR VARIOUS ROCK TYPES

ROCK TYPE	COMPRESSIVE STRENGTH KP/CM^2	COMPRESSIVE STRENGTH PSI	TENSILE STRENGTH KP/CM^2	TENSILE STRENGTH PSI	SHEARING STRENGTH KP/CM^2	SHEARING STRENGTH PSI
GRANITE	1,000-2800	15,642-39,816	30-50	427-711	150-300	2,133-4,266
DIORITE	1,000-2,500	14,220 35,550	DNA		DNA	
GABBRO	1,000-1,900	14,220-27,018	DNA		DNA	
BASALT	2,000-3,500	28,440-49,770	DNA		DNA	
FELSITE	2,000-2,900	28,440-41,238	DNA		DNA	
MARBLE	800-1,500	11,376-21,330	30-90	427-1,280	100-300	1,422-4,266
SLATE	700	9,954	250	3,555	150-250	2,133-3,555
SANDSTONE	500-1,500	7,110-21,330	10-30	142-427	50-150	711-2,133
LIMESTONE	400-1,400	5,688-11,908	30-60	427-853	100-200	1,422-2,844
SALT	352	5,000	DNA		DNA	

*DNA = DATA NOT AVAILABLE

of the existing limestone mines are rather shallow, less than 100 feet in depth, because of the large-volume economics of these operations. There are a few mines, however, that have been excavated to sufficient depths to be potentially useful for compressed air storage.

Dolomite is much like limestone, in that it is commonly mined for building stone from near-surface formations by large-volume extraction methods. It often occurs in deposits associated with limestone or resulting from limestone alteration, such as magnesium carbonate replacing calcium carbonate.

Shale lithologies include a wide range of thin-bedded fissile rocks composed of silt and clay size particles. Thick shale deposits occur in many regions of the United States (Figure 3-28). Thick shale sequences are commonly included in the stratigraphic makeup of most large depositional basins. The major salt basins described later in the text also contain extensive shale deposits both above and below the evaporites. In addition, thick shales occur throughout the Rocky Mountain region from northern New Mexico to Montana and North Dakota; within the Central Valley of California; under much of North Texas, Oklahoma, Arkansas, and eastern Nebraska; and in southern Illinois and Indiana. Less extensive shale deposits are found in numerous other regions of the United States. It has been estimated that as much as 40 percent of all sedimentary rocks can be classified as shale, claystone or mudstone.

The mechanical properties of shale are not ideal for mining, although several successful caverns have been developed for LPG storage. Typically existing strengths are of the order of 2000 to 5000 psi. Most problems can be attributed to weak planes of bedding, relatively low compressive strengths, and the capability of some shales to swell in a humid environment. Some advantages of shale caverns include their low porosity and permeability, plus a moderate degree of plasticity which helps to heal fractures and passively relieve stress.

Shales that absorb water are usually rich in montmorillonite clays. (Montmorillonite is hydrated alumina silicate: $Al_2(OH)_4O_2Si_4O_6(OH)_2\,n\,H_2O$. The Al is often replaced by Mg or Fe.) Montmorillonite may be swollen from 3 to 10 times its normal size by absorption of water and may lose all of its structural integrity in the process.

Montmorillonite-rich shales are most common in Mesozoic and Cenozoic Age Deposits; they rarely occur in older shales. In the midcontinent region, swelling clays are rarely encountered below a depth of 600 feet, and there is some evidence that the depth of burial (i.e., degree of overburden pressure) may influence the amount of montmorillonite present in a given shale deposit.

Marine shales are typically more uniform in mineral composition than nonmarine shales. They are preferred for mining, because there is less possibility of encountering unexpected lithologies such as water-saturated sandstone within a formation.

The extraction ratios used in mining shales are relatively low as compared to most other lithologies. This is because of the inherent roof stability problems and generally low compressive strengths of most shale deposits. As a consequence, the cost of shale mines is often higher than comparable mines in other lithologies. Furthermore, the areal dimensions will usually be greater for shale caverns than for comparable volumes of mined space in other lithologies.

On the basis of mining feasibility, caverns in shale can be successfully constructed; however, they do present greater risks and should be ranked relatively low in comparison to the other cavern environments under consideration.

Sandstone rocks are composed of quartz and/or other small grains held together by a cementing agent such as calcite, silica, clay, or iron oxides. Sandstone deposits are either stratified, thinly laminated, or massive and thick-bedded, according to their mode of origin. The crushing strength of consolidated standstone is widely variable between 1,500 and 15,000 psi. Porosity ranges for typical sandstone deposits are 15 to 30 percent. The permeability may be high (~500 millidarcys) because of large, interconnected pores, but silty and dense sandstone formations often have much-reduced permeability values (~0.01 to 10 millidarcys).

Sandstone formations in large sedimentary basins very commonly yield vast quantities of oil and gas, and/or water (brine) where gas and oil are missing. The storage of natural gas in expended reservoir formations so it can be withdrawn during periods of high use has become an important element in the natural gas industry.

A.4 SALINE LITHOLOGIES

Salt lithologies, both domal and bedded, lend themselves to the construction of solutioned storage facilities in areas where salt thickness is great enough. Several factors contribute to salt's extreme usefulness for storage; among these are impermeability, ease of construction, lithostatic stability, lack of requirement for hydrostatic seal, and in several cases proximity to load centers.

Originally deposited as bedded strata in confined shallow marine basins, the salt beds have been buried and, in the case of the domal salts, extruded upward by temperature and pressure into the overlying strata. Most of these domal structures are overlain by caps of anhydrite, possibly formed as a result of dissolution of the salt in contact with freshwater environments, only to be replaced by anhydritic precipitation.

The nature of salt (plasticity) lends itself to storage; salt does not tend to creep at temperatures below 170 F. Creep is also influenced by the lithostatic pressure on the strata or dome.

Appendix B

SALT FORMATIONS IN THE UNITED STATES

Salt deposits occur in many areas of the United States (Ref. 1). The major component of these deposits is sodium chloride, but also commonly associated with them are gypsum (hydrated calcium sulfate), anhydrite (anhydrous calcium sulfate), potassium chloride and other alkali metal salts, as well as clay or shale. The presence and distribution of these impurities profoundly effect both the mechanical properties of the rock salt and the ease of solution mining of the formation. The rock salt was originally deposited in confined, shallow marine basins. Subsequent complex geological processes have influenced the structure and properties of the deposits. The major salt basins and locations of operating conventional salt mines are shown in Figure 3-19 of this report.

B.1 BEDDED SALT OCCURRENCES

The major bedded salt deposits are found in the north central states, in the southwestern high plains, and in Montana, Wyoming, and the Dakotas. These deposits are associated with major depositional basins: the Appalachian Basin, the Permian Basin, and the Williston Basin. Since the conditions of deposition and subsequent history of these regions differ from one another, the characteristics of the deposits in each area will be separately described.

APPALACHIAN BASIN

The bedded salt deposits in the Appalachian Basin include several individual beds deposited during the Silurian period of the Paleozoic era (Ref. 6). The Silurian salt (Salina Formation) beds have a maximum aggregate thickness of approximately 900 feet in the deep southern part of the Appalachian Basin. Individual salt beds occasionally reach 400 feet in thickness, but this usually includes many thin, interbedded shales and anhydrites. The depth to the salt in the Appalachian Basin ranges from less than 1180 feet along an east-west trending line south of Lake Ontario to more than 8000 feet north of the Appalachian Structural Front, which trends northeastward across central Pennsylvania and south central New York. The Salina beds generally dip southward at about 45 to 50 feet per mile in the Appalachian Basin. The Silurian bedded deposits extend from New York State westward across Pennsylvania and northeastern Ohio. They thin appreciably from north-central Ohio to southeastern Michigan, where the Findlay-Algonquin Arch, a deep structural uplift, cuts across north-northeastward into Canada. The salt deposits are either absent or very thin and discontinuous across northwestern Ohio, but they thicken into the Michigan Basin to the northwest. (Figure B-1).

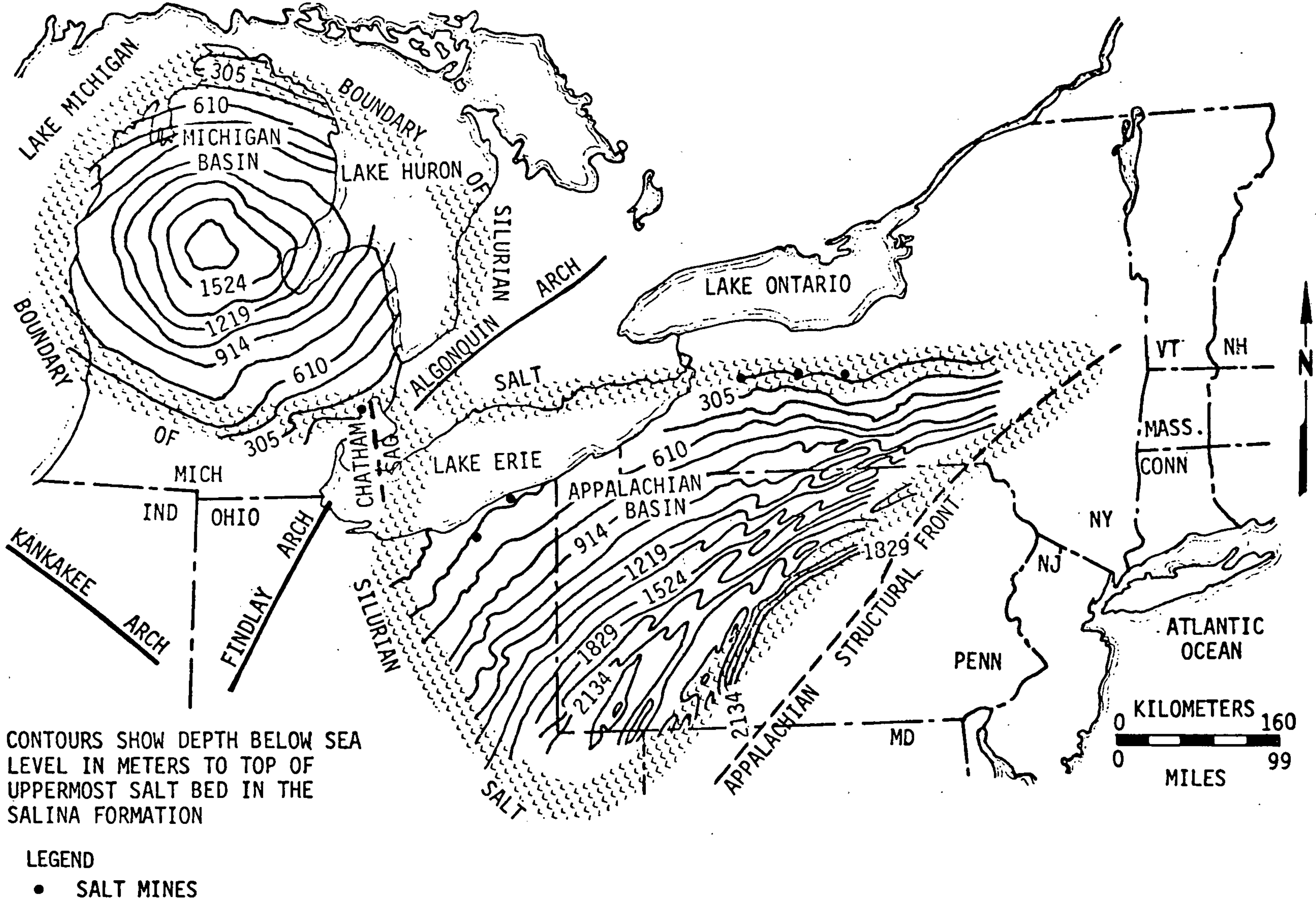

Figure B-1. Silurian Salt in the Appalachian and Michigan Basins

MICHIGAN BASIN

The Michigan Basin is a roughly circular sedimentary basin centered in the middle of the southern Michigan peninsula (Ref. 3). The strata gently dip and thicken toward the center of the basin, where they reach a maximum depth of nearly 12,000 feet. The Silurian salt deposits are otherwise deeper toward the center of the basin. Near the perimeter of the basin the salt beds occur at a depth of about 1000 feet, while in the center they are more than 5000 feet deep. The Silurian salt in the Michigan Basin is shown in Figure B-1.

PERMIAN BASIN

The Permian Salt Basin is a broad deposition trough extending from western Kansas to southwestern New Mexico and West Texas. The salt deposits range from Early Permian Age in the northern area to Middle Permian Age in the southern basin area. The aggregate salt thickness ranges from 0 to 50- feet over most of the basin, but locally increases to 3000 feet in southeastern New Mexico. In the Kansas salt beds, gypsum is sometimes present as thin interbeds and/or adjacent thick strata, while farther south both anhydrite and gypsum are commonly interbedded with the salt.

The strata dip very gently to the west from central Kansas to near the Colorado border. The depth to the salt in the northern basin ranges from about 410 feet in central Kansas to more than 1500 feet in the Oklahoma panhandle. The depth of burial is more a function of thickening overburden toward the Rocky Mountain Front than a result of deep-seated structural control. In southeastern New Mexico, buried reefs and tectonic adjustment are responsible for the much thicker and deeper salt occurrences. The Permian Basin salts and significant structural features are illustrated in Figure B-2.

B.2 DOMED SALT OCCURRENCES

The great majority of United States salt domes occur in the Gulf Coast states of Texas, Louisiana, Mississippi, and Alabama (Refs. 2 and 4). Other dome-like salt deposits are located in the Paradox Basin of southeastern Utah, the Virgin River Valley of southern Nevada and northwestern Arizona, and the Luke salt body in west-central Arizona. The Utah and Arizona-Nevada salt bodies are elongated deposits formed in association with anticlinal structures. They probably represent an intermediate phase between undisturbed bedded salt and well-developed salt domes. At least a few of the Paradox Basin diapirs have pierced the overlying strata and maintain a legitimate salt dome status.

GULF COAST EMBAYMENT

The Gulf Coast Embayment comprises a large region of land bordering the Gulf of Mexico which has some 263 known or suspected salt domes. The

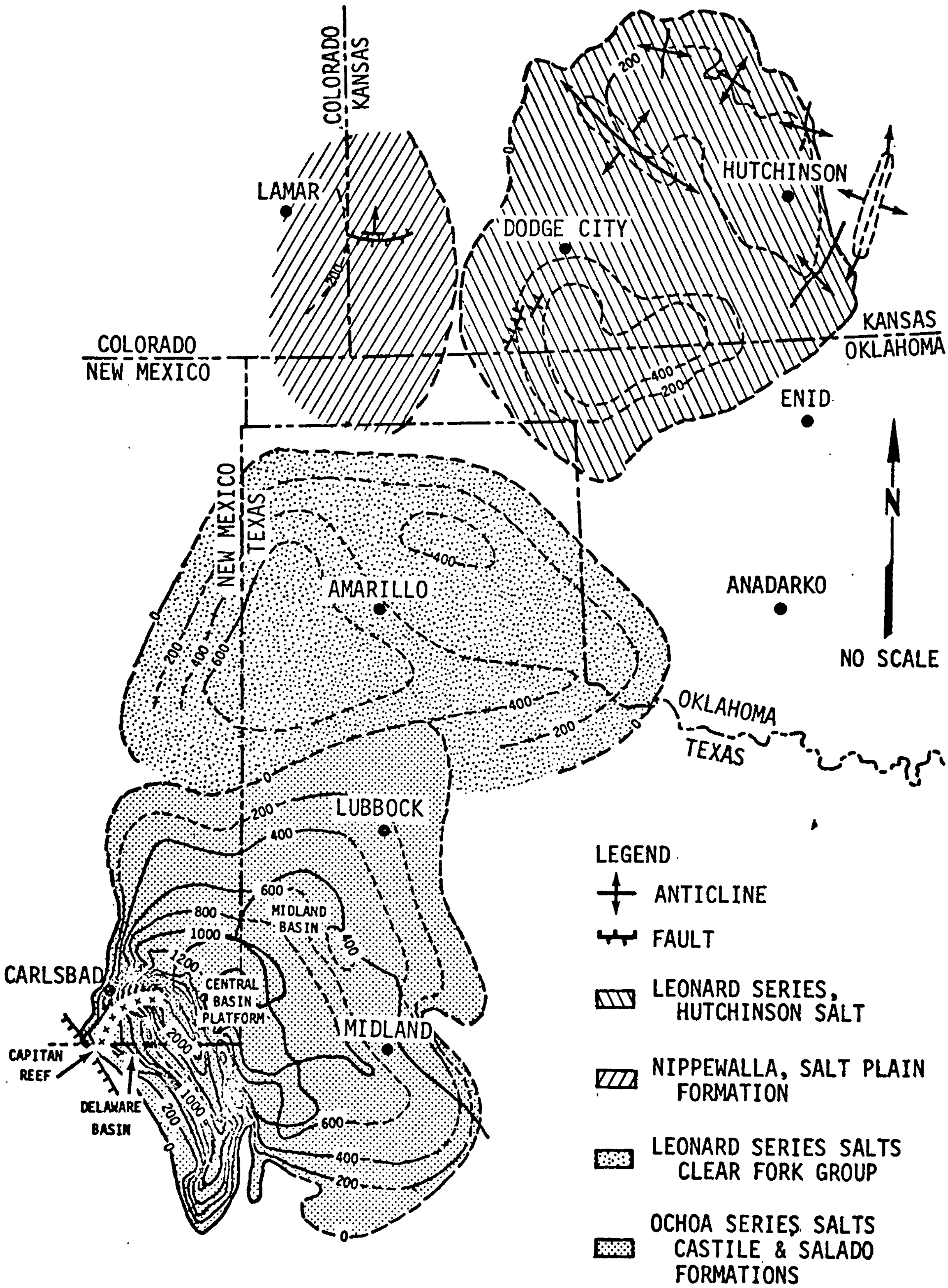

Figure B-2. Thickness and Distribution of Permian Basin Salts large majority of these domes occur near the coast, in what has been classified as the Coastal Subprovince. The remaining domes occur in three deep basins in the Interior Subprovince. A large portion of this region is underlain at considerable depth by the Louann Salt Formation probably of the Triassic Age. The Embayment is a very active depositional basin containing enormous quantities of Mesozoic and Cenozoic sediments deposited by ancient and modern rivers and streams. It has been estimated on the basis of geophysical data that more than 65,000 feet of sediment overlies the basement rock in southern Louisiana. The Gulf Coast Embayment and salt dome areas are illustrated in Figure B-3.

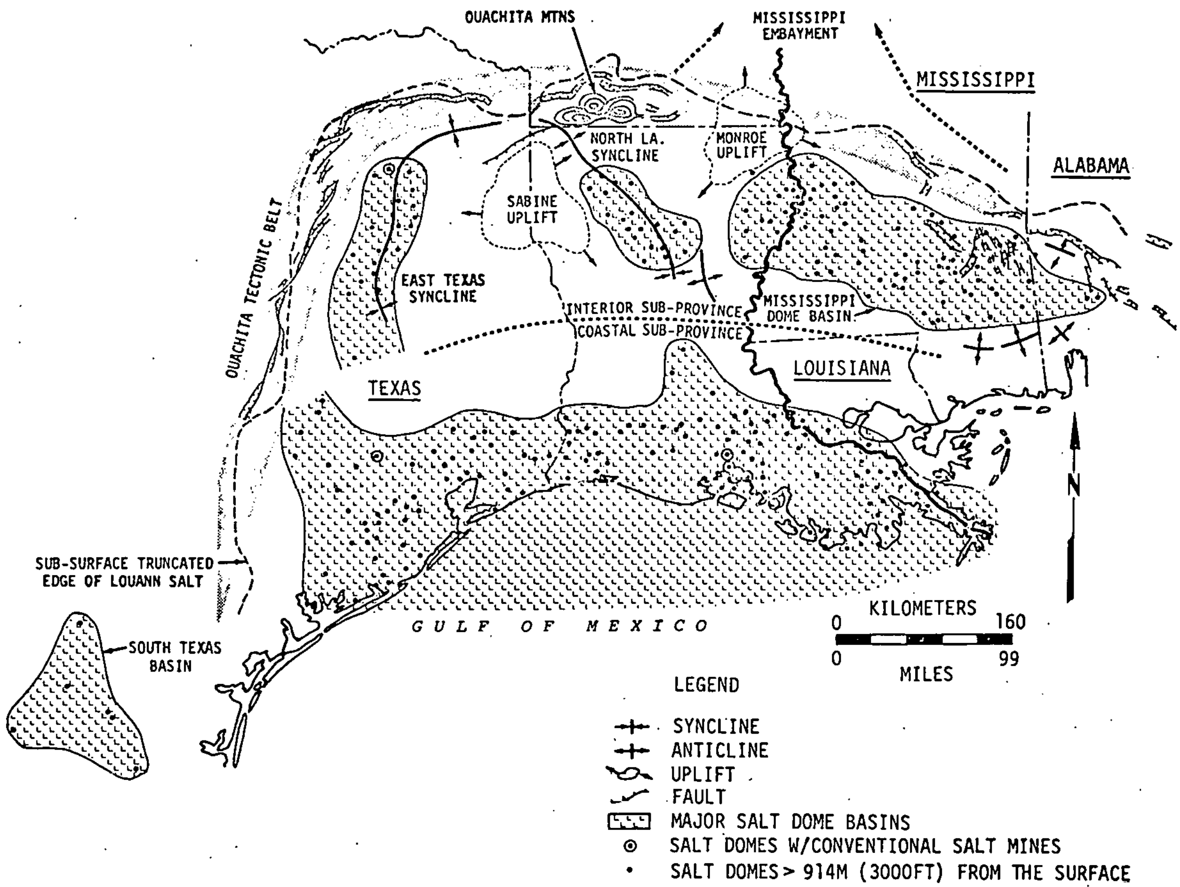

Figure B-3. Gulf Coast Embayment

In addition to their geographic separation, the Coastal and Interior salt domes possess several other noteworthy differences. The Interior domes are believed to have formed first and to have originated from shallower depths than the Coastal Domes. They commonly contain a higher percentage of impurities (usually anhydrite disseminated throughout the salt), which act to make the interior dome salt somewhat stronger than the purer (NaCl) coastal dome salt.

The salt source for all of the Gulf Coast salt domes is believed to be the Louann Salt, which is a thick evaporite sequence within the Eagle Mills Formation. Following deposition of the salt, some 175 million years ago, the regional basin has undergone long periods of sedimentary deposition. Today the aggregate thickness of overburden sediment ranges from 5000 feet in southern Arkansas to more than 50,000 feet near the present Gulf Coast.

The major structural features of the Gulf Coast Embayment include the Ouchita Tectonic Belt, a zone of folded strata which marks the perimeter of the Embayment. The Ouchita folding extends from southeast Texas north to southern Arkansas and then southeast to central Mississippi.

The Interior Province salt dome basins and interbasin uplifts are the primary structural features of the Interior Embayment region. From west to east these are the East Texas Syncline, the Sabine Uplift, the North Louisiana Syncline, the Monroe Uplift, and the Mississippi Dome Basin. Only limited faulting is evident; it is usually related to slumping or occurs in proximity to intruding salt plugs. The sedimentary strata dip gently southward toward the coast and thicken locally in the basins.

The basement structure of the Coastal Province is not well known because of the extreme thickness of overlying sediments. A few deep-seated anticlines have been recognized and they appear to provide the common source of salt for some adjacent domes. It seems likely that many other domes are also rooted in buried anticlinal structures, since the folding acts to concentrate the salt and weaken the overlying strata.

Slump faulting parallel to the coast is very common in the coastal areas of the Embayment. The slump faults have been attributed to differential compaction of the rapidly accumulating sediments. Seismicity of the Gulf Coast area has remained very low during historic times, and the thick sequence of uniform deposition would indicate few disturbances during a long period of geologic time.

Figure B-4 shows a tabulation, by location, of all coastal salt domes less than 3000 feet deep. Table B-1 is a cross index of numbered areas in this figure, containing pertinent data on the domes.

The salt domes have been studied by many researchers during the past 50 years because of their intimate association with oil, gas, and sulfur reserves. Some of the resulting theories and conclusions that have been developed are briefly outlined as follows:

- The salt domes originate from the thick Louann Salt, which is isolated at depths of 15,000 feet or more.
- Many diapirs, initially formed in local deep-seated anticlines, acted to concentrate the salt and weaken the overlying strata along the anticlinal axis.

- Upward movement is a form of isostatic adjustment caused by the relative differences in density of rock salt and the surrounding sediments. The specific gravity of salt averages about 2.2 versus a specific gravity of shale, siltstone, sandstone, limestone, and other Gulf Coast sediments that average over 2.4 and increase at depth. Salt densities have been found to remain constant or vary only slightly at increased depth and pressure. On the basis of laboratory and drill hole data it appears that rock salt underlying 60,000 feet of sediment will have the same density as rock salt near the surface. As a result, the lighter salt tends to float to the surface, much as a bubble rises in water.

- The salt plug undergoes some unexplained refining process as it migrates upward, as evidenced by the high purity of most dome salt (commonly ranging from 95 to 99 percent NaCl versus approximately 90 percent NaCl for bedded salt deposits).

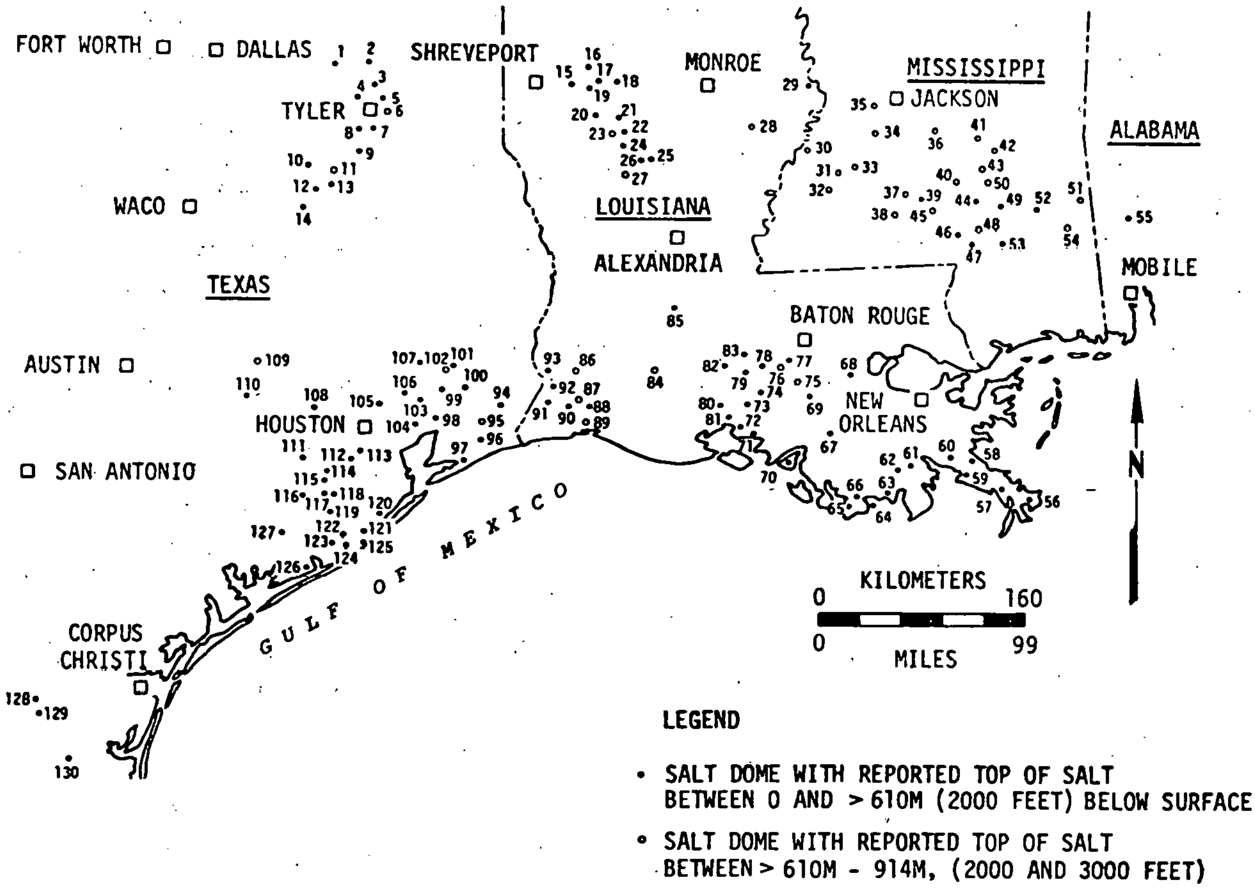

Figure B-4. Index Map of Gulf Coast Salt Domes

Table B-1

GULF COAST EMBAYMENT SALT DOMES LESS THAN 3000 FEET DEEP

Map Number	Name	County/Parish and State	Depth to Cap Rock (ft)	Depth to Salt (ft)	Past or Present Uses
		INTERIOR SUBPROVINCE			
		Northeast Texas Basin			
1	Grand Slaine	Van Zandt, Tex.	188	212	Salt mine, brine production
2	Hainesville	Quitman, Tex.	*Unknown	1155	LPG storage, abandoned oil wells
3	Steen	Tyler, Tex.	75	300	Abandoned brine wells
4	Mount Sylvan	Tyler, Tex.	*Unknown	613	N/A
5	East Tyler	Tyler, Tex.	800	890	LPG storage
6	Whitehouse	Tyler, Tex.	485	2000	N/A
7	Bullard	Tyler, Tex.	*Unknown	527	N/A
8	Brooks	Tyler, Tex.	195	220	Abandoned brine and oil wells
9	Boggy Creek	Palestine, Tex.	*Unknown	1829	Oil production
10	Bethel	Palestine, Tex.	1440	1600	Oil production
11	Keechi	Palestine, Tex.	*Unknown	2162	Oil exploration
12	Butler	Freestone, Tex.	*Unknown	312	LPG storage, rock quarry, abandoned oil well
13	Palestine	Palestine, Tex.	120	122	Abandoned brine wells
14	Oakwood	Freestone, Tex.	703	800	Oil production
		North Louisiana Basin			
15	Bistineau	Webster, La.	1375	1500	Abandoned brine wells
16	Minden	Minden, La.	1372	1912	Oil production
17	Gibsland	Bienville, La.	612	885	LPG storage
18	Arcadia	Bienville, La.	1282	1400	LPG storage
19	Vacherie	Minden, La.	658	777	N/A
20	Kings	Bienville, La.	160	172	Abandoned brine wells
21	Rayburns	Bienville, La.	Surface	115	Abandoned brine wells
22	Prices	Winnfield, La.	1000	1300	Abandoned brine wells
23	Chestnut	Natchitoches, La.	*Unknown	2450	N/A
24	Drakes	Winnfield, La.	200	850	Abandoned brine wells
25	Cedar Creek	Winnfield, La.	500	750	N/A
26	Winnfield	Winnfield, La.	Surface	200	Salt mine, limestone quarry
27	Coochie Brake	Winnfield, La.	Surface	2500	N/A

*Cap rock missing or information unavailable.

NOTE: Oil production normally occurs around flanks of salt domes; sulfur production usually from cap rock formations.

Table B-1 (Cont'd)

GULF COAST EMBAYMENT SALT DOMES LESS THAN 3000 FEET DEEP

Map Number	Name	County/Parish and State	Depth to Cap Rock (ft)	Depth to Salt (ft)	Past or Present Uses
		Mississippi Basin			
28	Gilbert	Winnsboro, La.	1425	1770	N/A
29	Walnut Bayou	Tallulah, La.	2650	2740	N/A
30	Bruinsburg	Port Gibson, Miss.	1629	2016	Oil exploration
31	McBride	Fayette, Miss.	1865	2205	Shut-in gas wells.
32	Leedo	Fayette, Miss.	1359	2065	N/A
33	Allen	Copiah, Miss.	2445	2774	N/A
34	Carmichael	Hinds, Miss	2685	2966	N/A
35	Oakley	Raymond, Miss.	2600	2634	Abandoned oil wells
36	D'Lo	Mendenhall, Miss.	2090	2400	N/A
37	Monticello	Monticello, Miss.	2256	2757	Exploratory oil well
38	Ruth	Lincoln, Miss.	2208	2700	Exploratory oil well
39	Arm	Monticello, Miss.	1218	1930	Oil exploration
40	Dry Creek	Covington, Miss.	1986	2300	N/A
41	Raleigh	Raleigh, Miss	1490	2140	Oil production
42	New Home	Raleigh, Miss	1520	2595	Oil exploration
43	Dont	Collins, Miss.	2032	2300	N/A
44	Richmond	Collins, Miss.	1610	1954	N/A
45	Oakvale	Prentiss, Miss.	1836	2696	N/A
46	Lampton	Columbia, Miss.	1365	1647	N/A
47	Tatum	Purvis, Miss.	872	1503	N/A
48	Midway	Purvis, Miss.	1613	2522	Oil exploration
49	Petal	Hattiesburg, Miss.	1235	1739	LPG storage
50	Eminence	Collins, Miss.	1964	2440	N/A
51	County Line	Leaksville, Miss.	1239	2170	Oil exploration
52	Richton	New Augusta, Miss.	497	722	N/A
53	McLaurin	Hattiesburg, Miss.	1705	1933	N/A
54	Byrd	Leaksville, Miss.	1440	2058	N/A
55	McIntosh	Washington, Ala.	270	400	Brine production
		COASTAL SUBPROVINCE			
		Louisiana			
56	Garden Island Bay	Plaquemines, La.	1691	2014	Oil and sulfur production
57	Venice	Plaquemines, La.	*Unknown	1328	Oil production

*Cap rock missing or information unavailable.

NOTE: Oil production normally occurs around flanks of salt domes; sulfur production usually from cap rock formations.

Table B-1 (Cont'd)

GULF COAST EMBAYMENT SALT DOMES LESS THAN 3000 FEET DEEP

Map Number	Name	County/Parish and State	Depth to Cap Rock (ft)	Depth to Salt (ft)	Past or Present Uses
58	Potash	Plaquemines, La.	678	1300	Oil production
59	Lake Washington (Grand Ecaille)	Plaquemines, La.	1070	1500	Oil and sulfur production
60	Lake Hermitage	Plaquemines, La.	905	1400	Oil production
61	Clovelly	Lafourche, La.	394	1168	Oil production
62	Bully Camp	Lafourche, La.	1256	1296	Oil production
63	Lake Barre	Terrebonne, La.	721	758	Oil production
64	Bay St. Elaine	Terrebonne, La.	710	1200	Oil production, abandoned sulfur wells
65	Dog Lake	Terrebonne, La.	1439	1725	Oil production
66	Four Isle Bay	Terrebonne, La.	498	1305	Oil production
67	Chocahoula	Thibodaux, La.	875	1100	Oil and brine production abandoned sulfur wells
68	Sorrento	Ascension, La.	1568	1717	LPG storage, oil and brine production
69	Napoleonville	Napoleonville, La.	350	650	Oil and brine production
70	Belle Isle	St. Mary, La.	110	137	Salt mine, oil production
71	Cote Blanche Island	St. Mary, La.	*Unknown	298	Salt mine, oil production
72	Weeks Island	New Iberia, La.	Surface	88	Salt mine, oil production
73	Iberia	Iberia, La.	**1078	805	Oil production
74	Fausse Point	New Iberia, La.	792	823	Oil production
75	White Castle	Plaquemines, La.	1693	2313	Oil production
76	Bayou Bleu	Plaquemines, La.	2793	2801	Oil production
77	Bayou Choctaw	Plaquemines, La.	237	629	LPG storage, oil and brine production
78	Bayou Bovillon	Martinville, La.	1260	1375	Oil production
79	Section 28	Martinville, La.	951	1190	Oil production
80	Jefferson Island	New Iberia, La.	**525	31	Salt mine, abandoned sulfur wells, oil production
81	Avery Island	New Iberia, La.	*Unknown	6	Salt mine, oil production
82	Anse La Butte	St. Martin, La.	*Unknown	160	LPG storage, oil and brine production
83	Plumb Bob	St. Martin, La.	1030	1189	Oil production
84	Jennings	Crowley, La.	2000	2512	Oil production
85	Pine Prairie	Ville Platte, La.	Surface	516	LPG storage, abandoned quarry

*Cap rock missing or information unavailable.
**Cap rock does not overlie the salt.

NOTE: Oil production normally occurs around flanks of salt domes; sulfur production usually from cap rock formations.

Table B-1 (Cont'd)

GULF COAST EMBAYMENT SALT DOMES LESS THAN 3000 FEET DEEP

Map Number	Name	County/Parish and State	Depth to Cap Rock (ft)	Depth to Salt (ft)	Past or Present Uses
86	Sulfur Mines	Lake Charles, La.	315	1460	LPG storage, oil and brine production
87	East Hackberry	Cameron, La.	2749	2950	LPG storage, oil production
88	Big Lake	Cameron, La.	*Unknown	1295	Oil production
89	Calcasieu Lake	Cameron, La.	1446	2345	Oil production
90	West Hackberry	Cameron, La.	1234	1960	Oil and brine production
91	Black Bayou	Cameron, La.	881	1035	Oil production
92	Vinton	Lake Charles, La.	384	925	Oil production
93	Starks	Lake Charles, La.	1202	1925	Oil and brine production, abandoned sulfur wells
		Texas			
94	Spindletop	Jefferson, Tex.	700	1200	Oil and sulfur production
95	Fannett	Jefferson, Tex.	741	2200	LPG storage, oil and sulfur production
96	Big Hill	Jefferson, Tex.	200	1300	LPG storage, oil production
97	High Island	Galveston, Tex.	150	1300	Oil production
98	Moss Bluff	Liberty, Tex.	591	1160	Oil and sulfur production
99	Hull	Liberty, Tex.	260	595	LPG storage, oil production
100	Sour Lake	Hardin, Tex.	660	719	LPG storage, oil production
101	Saratoga	Hardin, Tex.	1500	1900	Oil production
102	Batson	Hardin, Tex.	1080	2050	Oil production
103	South Liberty	Liberty, Tex.	275	480	Oil production
104	Barbers Hill	Chambers, Tex.	350	1000	LPG storage, oil and brine production
105	Humble	Harris, Tex.	700	1200	Oil production
106	North Dayton	Liberty, Tex.	580	800	Oil production
107	Davis Hill	Liberty, Tex.	800	1200	Abandoned oil wells
108	Hockley	Harris, Tex.	74	1000	Salt mine, oil production
109	Clay Creek	Washington, Tex.	1750	2400	Oil production
110	Brenham	Washington/ Austin, Tex.	800	1150	Oil production
111	Orchard	Fort Bend, Tex.	285	375	Oil and sulfur production

*Cap rock missing or information unavailable.

NOTE: Oil production normally occurs around flanks of salt domes; sulfur production usually from cap rock formations.

Table B-1 (Cont'd)

GULF COAST EMBAYMENT SALT DOMES LESS THAN 3000 FEET DEEP

Map Number	Name	County/Parish and State	Depth to Cap Rock (ft)	Depth to Salt (ft)	Past or Present Uses
112	Blue Ridge	Fort Bend, Tex.	143	230	LPG storage, oil and brine production
113	Pierce Junction	Harris (Houston), Tex.	630	950	LPG storage, oil and brine production
114	Big Creek	Fort Bend, Tex.	450	635	Oil production
115	Long Point	Fort Bend, Tex.	550	930	Oil and sulfur production
116	Boling	Warton, Tex.	383	975	Oil and sulfur production
117	Damon Mound	Brazoria, Tex.	Surface	529	Oil production, abandoned sulfur wells
118	Nash	Brazoria, Tex.	620	950	Oil production, abandoned sulfur wells
119	West Columbia	Brazoria, Tex.	650	750	Oil production
120	Hoskins Mound	Brazoria, Tex.	574	1150	Abandoned oil and sulfur wells
121	Stratton Ridge	Brazoria, Tex.	850	1250	LPG storage, oil and brine production
122	Clemens	Brazoria, Tex.	530	1380	LPG storage, shut-in gas wells, abandoned sulfur wells
123	Hawkinsville	Matagorda, Tex.	95	450	Abandoned oil wells
124	Allen	Brazoria, Tex.	760	1380	Oil production
125	Bryon Mound	Brazoria, Tex.	680	1112	Oil and brine production, abandoned sulfur wells
126	Gulf	Matagorda, Tex.	825	1100	Abandoned oil and sulfur wells
127	Markham	Matagorda, Tex.	1380	1417	LPG storage, oil production
128	Palangana	Duval, Tex.	350	500	Brine production, abandoned oil and sulfur wells
129	Piedras Pintas	Duval, Tex.	385	1350	Oil production
130	Gyp Hill	Brooks, Tex.	Surface	1175	Oil and gas production

NOTE: Oil production normally occurs around flanks of salt domes; sulfur production usually from cap rock formations.

PARADOX BASIN

The Paradox Basin is an elongated northwest-trending sedimentary basin extending from southwestern Colorado into southeastern Utah (Ref. 5). It is approximately 80 miles wide and 160 miles long.

Salt occurs in the Hermosa Formation of Pennsylvanian Age, along with limestone, dolomite, sandstone, shale, gypsum, and anhydrite. The Hermosa Formation varies from 1000 feet thick near the perimeter to 14,000 feet thick in deformed anticlinal folds. The deepest part of the basin trends parallel to the Uncompahgre Uplift along the northeast side of the basin. Northwest-trending ridges and valleys dominate the topography of the basin and are the result of strong folding, faulting, and subsequent erosion.

The thickness of the salt to the anticlines ranges from 2000 feet to 10,000 feet. The original thickness of salt was estimated to have been 5000 feet in the deepest part of the evaporation basin. Subsequent structural deformation has been largely responsible for the present salt thicknesses and distribution. The major basin structures and salt occurrences are illustrated in Figure B-5.

The depth to salt is extremely variable throughout the basin because of the high degree of tectonic deformation. Depths range from 400 feet in a well drilled in Sinbad Valley to 5400 feet in southeastern Lisbon Valley. The purity of the salt formation ranges from less than 20 percent where the salt exists as thin interbeds to nearly 90 percent where the salt has been deformationally concentrated in folds.

Although the basin was once subjected to a high degree of tectonic deformation, it has remained seismically quiescent during historic time. There are no population or load centers within several hundred kilometers of the Paradox Basin; however, the four-corners region of New Mexico, Arizona, Colorado, and Utah does possess a number of very large coal-fired electrical generating plants.

SOUTHERN NEVADA SALT

A number of isolated salt structures have been identified in southern Nevada, northwestern Arizona, and west-central Arizona. Although it is unclear whether these are truly dome salt, they do appear to have some dome-like characteristics.

The Virgin Valley salt dome in southern Nevada is now largely submerged under the Overton Arm of Lake Mead. In addition to the dome-shaped structure there are several adjacent lens-shaped deposits which range up to 50 feet thick in outcrop and may be even thicker at depth. The areal extend and distribution of the salt deposits in the Virgin Valley are not well defined. The

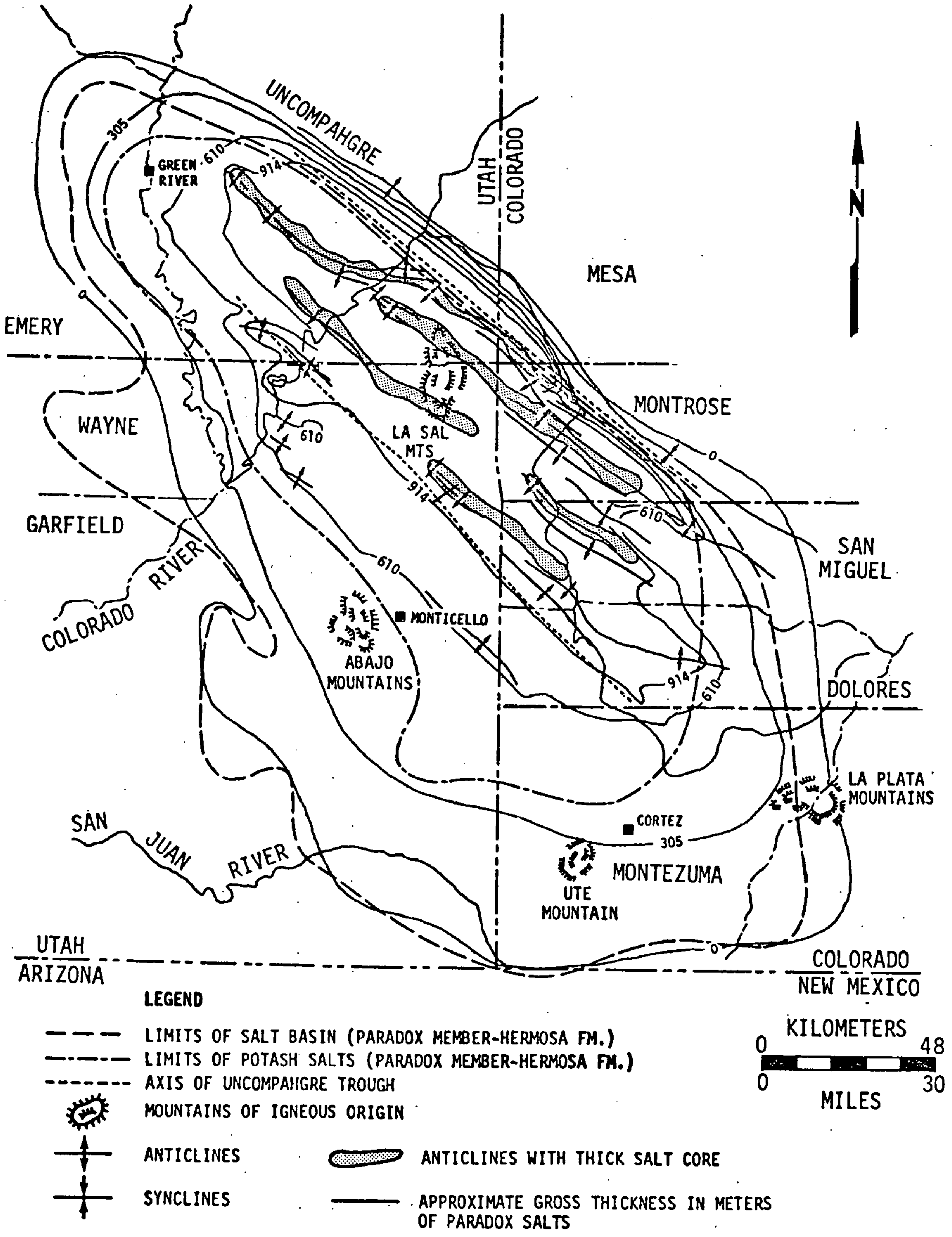

Figure B-5. Paradox Basin -- Structural/Isopach Map of Salt Bearing Formations suitability of the Virgin Valley salt for compressed air storage is uncertain; however, there is a powerplant located at Glendale, Nevada, approximately 12 miles west of the salt basin.

Drill holes south of the Colorado River in northwestern Arizona penetrated thick salt to 1000 feet at Red Lake. Another salt deposit is known in Detrital Wash, where the salt is greater than 500 feet thick at a depth of approximately 500 feet. The northwestern Arizona salt deposits are described as very pure, recrystallized NaCl. The salt apparently extends over several kilometers, but the boundaries are not well established.

LUKE SALT BODY

A large, isolated salt mass appearing as an elongated dome has been utilized for LPG storage near Phoenix, Arizona. The Luke salt dome is located approximately 17 miles west-northwest of Phoenix, near Luke Air Force Base. The salt mass is elongated on a north-south line and is roughly 10 miles long by 6 miles wide. Figure B-6 shows the physical outline of the Luke Salt Body.

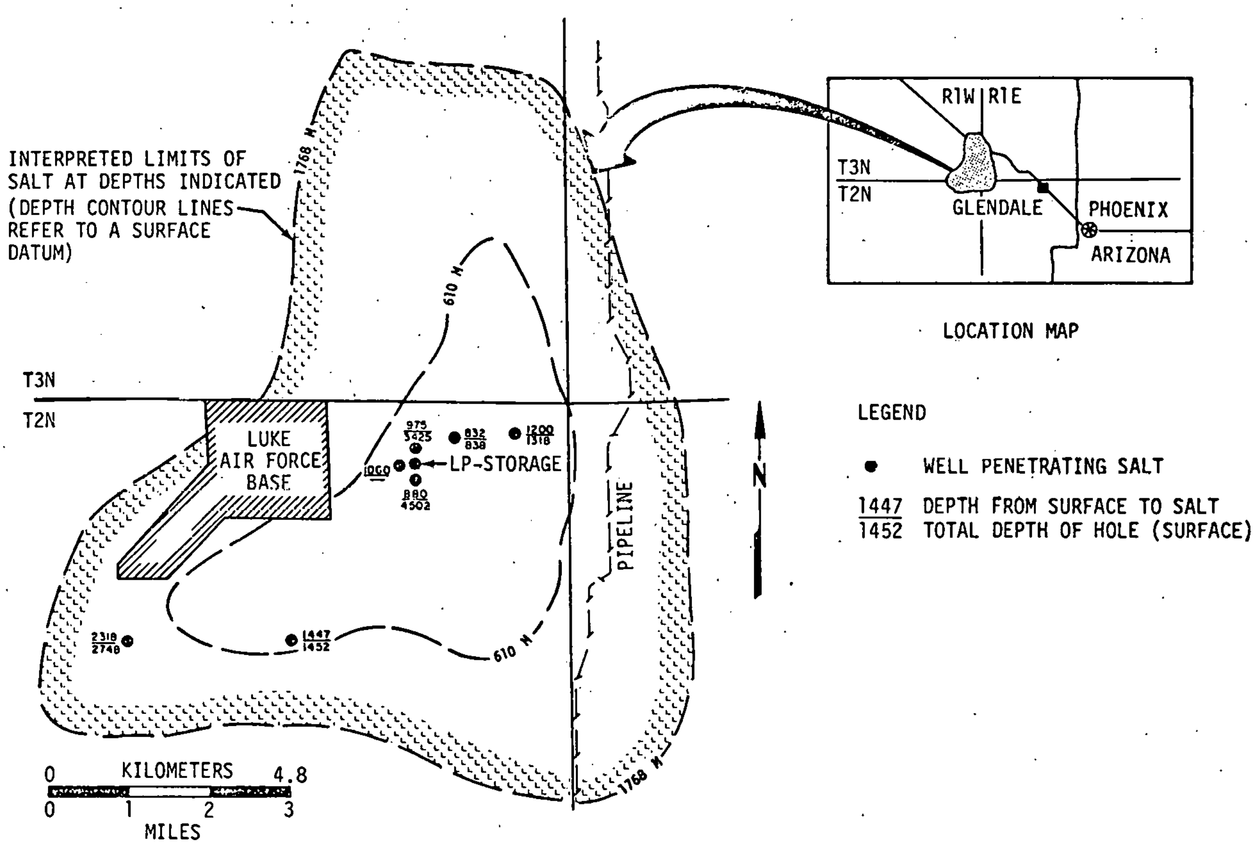

Figure B-6. Luke Salt Body

Very pure halite with many thin shale interbeds underlies a 60-foot-thick anhydrite cap rock at a depth of 800 feet. The salt base is believed to be at a depth greater than 6500 feet.

It is believed that either solution caverns or conventionally mined caverns could be developed in the Luke Salt Body for use as compressed air storage reservoirs.

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Appendix C

PROCEDURES FOR DETERMINING SITE SUITABILITY

Once a decision has been made to develop a cavern or aquifer for air storage, it will be necessary to select one or more suitable sites. The initial screening can be accomplished in either of two ways:

- The client can assign potential sites based on land availability and convenience to his operation.
- The client can indicate a region to be screened for potential storage sites on the basis of geologic and other technical criteria.

The latter procedure allows greater flexibility and increased likelihood of finding technically suitable storage sites, but current land use, availability, and convenience may ultimately overrule such selections. A tradeoff between these selection methods will provide a practical alternative in most cases.

Exploration for suitable sites will always begin with a thorough literature review of all natural conditions (geology, hydrology, structure stratigraphy, land use, topography) at and near a potential site. In many cases this initial research will eliminate a site from further consideration. If, however, all critical factors still appear favorable, a field exploration program can be developed to determine the feasibility of constructing an air storage cavern or reservoir at the site.

The following matrices (Figures C-1 and C-2) have been developed to indicate the types of data obtainable with the use of appropriate exploration techniques. The results of the preliminary literature review, coupled with the type of storage facility under consideration, will determine which techniques are to be used in the field exploration study. It must be pointed out that the state of the art is advancing, and new and/or improved techniques are continually being developed.

While it is not the intent of this brief appendix to present an entire exploration program, a basic plan is outlined here to provide an understanding of the scope of such studies:

1. Literature Review (leading to prefeasibility report)

   (Obtain information from libraries; Federal, state, and local government universities; technical publications, including maps, cross sections, photos, remote sensing imagery, drill-hole logs, geophysical data, and regulations.

2. Preliminary Property Reconnaissance

   Visit the site to determine any unusual conditions not found in

EXPLORATION TECHNIQUES

Category	Objective	INFORMATION SEARCH	PRELIMINARY SITE INSPECTION	MAPPING BY REMOTE SENSING	DIRECT SURFACE MAPPING	GEOPHYSICAL SURVEYS: SEISMIC REFRACTION	SEISMIC REFLECTION	ELECTRICAL RESISTIVITY	MAGNETIC	ELECTROMAGNETIC	GRAVITY	RADIOMETRIC	ACOUSTIC HOLOGRAPHY	SAMPLING: SURFACE SAMPLING	SUBSURFACE DRILLING: ROTARY	CHURN OR PERCUSSION	AUGER	WASH BORING	SUBSURFACE SAMPLING: DISTURBED SAMPLING	UNDIST.: OPEN TUBE	PISTON TUBE	CORING
GROUND TYPE		•	•	•	○	•	•	○	○	•	•	•		○	○	•	•	•	•	•	•	•
STRUCTURAL FEATURES	TYPE & WIDTH	•	○	•	○	○	○	○	○	○	○		•									•
	SPACING	○	•	•	•	•	•	○	•	○	○		•									•
	ORIENTATION	•	•	•	○	○	•	○	○	•	•		•									•
	TIGHTNESS	•	○		•									○								•
	FILLING MATERIAL	○	•		○									○	•	•	○		•			•
	SURFACE CHARACTER	○	○		•									○								•
GROUND CONDITIONS	DEGREE OF ANISOTROPY	•	○		○																	•
	STATE OF STRESS	•																				
	UNWEATHERED BEDROCK SURFACE	•				○		○			○				○	•	•		•			•
	GROUNDWATER VOLUME RATE INFLOW	•																				
	DEGREE OF DECOMP. OR ALTERATION	•	•	•	○	○		•	•					•	○	•	○		•			•
	PERMEABILITY	○																				
	WATER TABLE DEPTH	○				○		•							○	•	○					
	GROUND WATER COMPOSITION	•	•																			
	MOISTURE CONTENT	•																				
	SUSCEPTIBILITY TO EARTHQUAKES	•																				
	DANGEROUS GASES PRESENT	•																				
	UNCOMFORTABLE GROUND TEMPERATURE	•																				
PHYSICAL-MECHANICAL PROPERTIES	COMPRESSIVE STRENGTH	•																				
	MODULUS OF ELASTICITY	○				○																
	POISSON'S RATIO	•				○																
	CONSISTENCY	○																				
	HARDNESS (DRILLABILITY)	•			•	○	○								•	•			•			•
	SWELLING	•																				
	COHESION	•			•									•								
	ABRASIVENESS	•			•										○							
	SHEAR STRENGTH	○																				
	WEATHERING RESISTANCE	•	○	•	•									•								
	SOLUBILITY OF COMPONENTS	•			•									•								
	DENSITY	•				○	•				•											
	MODULUS OF RUPTURE	•																				
	POROSITY	•																				
	CREEP	•																				
VARIABILITY		•	•	•	•	○	•	•	•	•	○	•	•	•	•	•	•		•	•	•	○
LOCATION OF MAN-MADE STRUCTURES		•	•	•	•																	

Category	Objective	VISUAL OR PHOTOGRAPHIC	BOREHOLE LOGGING: ELECTRICAL LOGS: SPONTANEOUS POTENTIAL	CONVENTIONAL RESISTIVITY	MICRORESISTIVITY	FOCUSING ELECTRODE	INDUCTION	NUCLEAR LOGS: GAMMA RAY	NEUTRON	FORMATION DENSITY	SONIC	GRAVITATIONAL	CALIPER	TEMPERATURE	TRENCHES & PILOT TUNNELS	IN SITU TESTING: SOIL SHEARING STRENGTH	STATE OF STRESS	GROUND WATER HYDROLOGY	LABORATORY TESTING: SOIL: GRADATION	MOISTURE CONTENT	UNIT WEIGHT	POROSITY	CONSISTENCY	SHEARING STRENGTH	UNCONFINED COMP. STR.	PERMEABILITY	SWELLING
GROUND TYPE		•	○	•	•	•	•	•	•	•	•	•	•		•				•								
STRUCTURAL FEATURES	TYPE & WIDTH	•													•												
	SPACING	•													•												
	ORIENTATION	•													•												
	TIGHTNESS	•													•												
	FILLING MATERIAL	○													•												
	SURFACE CHARACTER	•													○												
GROUND CONDITIONS	DEGREE OF ANISOTROPY	•		○											○												
	STATE OF STRESS																•										
	UNWEATHERED BEDROCK SURFACE	•		•											•			•									
	GROUNDWATER VOLUME RATE INFLOW														•												
	DEGREE OF DECOMP. OR ALTERATION	•													•												
	PERMEABILITY			•							•							•								•	
	WATER TABLE DEPTH																										
	GROUND WATER COMPOSITION			○																							
	MOISTURE CONTENT																			•							
	SUSCEPTIBILITY TO EARTHQUAKES																										
	DANGEROUS GASES PRESENT								•	•					○												
	UNCOMFORTABLE GROUND TEMPERATURE													•	•												
PHYSICAL-MECHANICAL PROPERTIES	COMPRESSIVE STRENGTH																								•		
	MODULUS OF ELASTICITY										•																
	POISSON'S RATIO										•																
	CONSISTENCY																						•				
	HARDNESS (DRILLABILITY)														•												
	SWELLING														•												•
	COHESION														•												
	ABRASIVENESS														•												
	SHEAR STRENGTH															•								•	•		
	WEATHERING RESISTANCE														•												
	SOLUBILITY OF COMPONENTS																										
	DENSITY									•		•									•						
	MODULUS OF RUPTURE																										
	POROSITY								•	•	•	•										•					
	CREEP																										
VARIABILITY		•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
LOCATION OF MAN-MADE STRUCTURES															•												

Category	Objective	LABORATORY TESTING: ROCK: IDENTIFICATION	SPECIFIC GRAVITY	POROSITY	HARDNESS	ABRASION RESISTANCE	WEATHERING RESISTANCE	UNIAXIAL COMPRESSIVE STRENGTH	UNIAXIAL SHEAR STRENGTH	UNIAXIAL TENSILE STRENGTH	UNIAXIAL FLEXURAL STRENGTH	TRIAXIAL COMPRESSIVE STRENGTH	TRIAXIAL SHEAR STRENGTH	STATIC ELASTIC CONSTANTS	DYNAMIC ELASTIC CONSTANTS	PERMEABILITY	CREEP
GROUND TYPE		•															
STRUCTURAL FEATURES	TYPE & WIDTH																
	SPACING																
	ORIENTATION																
	TIGHTNESS																
	FILLING MATERIAL																
	SURFACE CHARACTER																
GROUND CONDITIONS	DEGREE OF ANISOTROPY																
	STATE OF STRESS																
	UNWEATHERED BEDROCK SURFACE																
	GROUNDWATER VOLUME RATE INFLOW																
	DEGREE OF DECOMP. OR ALTERATION																
	PERMEABILITY															•	
	WATER TABLE DEPTH																
	GROUND WATER COMPOSITION																
	MOISTURE CONTENT																
	SUSCEPTIBILITY TO EARTHQUAKES																
	DANGEROUS GASES PRESENT																
	UNCOMFORTABLE GROUND TEMPERATURE																
PHYSICAL-MECHANICAL PROPERTIES	COMPRESSIVE STRENGTH							•				•					
	MODULUS OF ELASTICITY													•	•		
	POISSON'S RATIO													•	•		
	CONSISTENCY																
	HARDNESS (DRILLABILITY)				•												
	SWELLING																
	COHESION																
	ABRASIVENESS					•											
	SHEAR STRENGTH								•				•				
	WEATHERING RESISTANCE						•										
	SOLUBILITY OF COMPONENTS																
	DENSITY		○														
	MODULUS OF RUPTURE										•						
	POROSITY			•													
	CREEP																•
VARIABILITY		•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
LOCATION OF MAN-MADE STRUCTURES																	

Figure C-1. Compatibility Matrix -- Exploration Techniques and Objectives

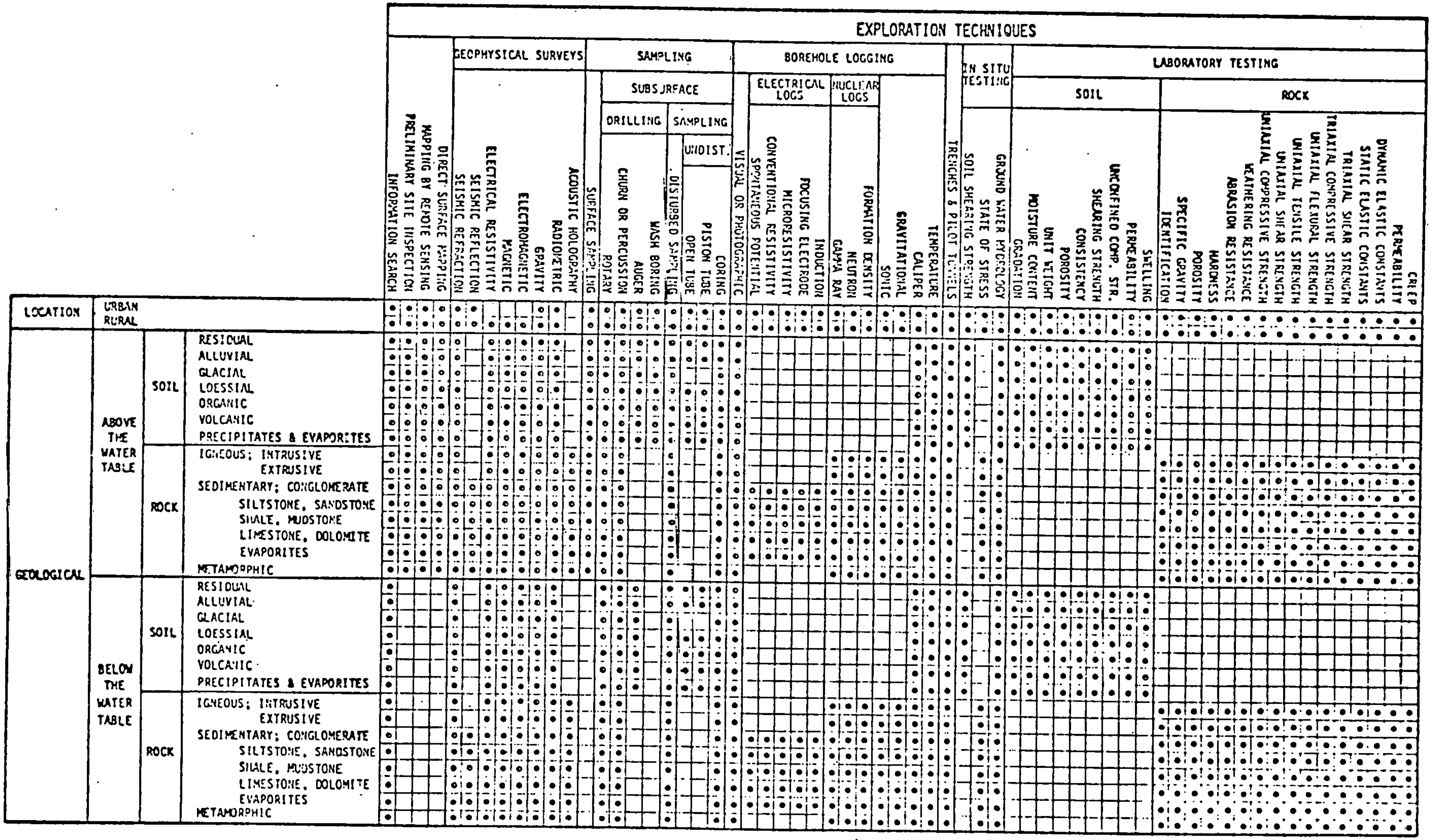

Figure C-2. Compatibility Matrix -- Relationship of Exploration Techniques to Air Storage Environments the literature; determine boundary controls, water availability, access, present land use, easements; check utilities and other on-site facilities; initiate contacts with local officials having regulatory or other interests in the project.

3. Field Investigations (Developed on the basis of 1 and 2, above, field programs will vary from site to site.)

   Geophysical Surveys -- Surface techniques such as resistivity, seismic, electromagnetic, and gravity.

   Systematic Drilling/Sampling Program -- Number, size, depth, and spacing of drill holes will vary with local conditions and the type of storage facility under consideration.

   - Conventionally Mines Caverns (approximately 2 inch cores) -- Four or more NX-size core holes (possibly larger diameter if borehole logging is required).
   - Solution Mined Caverns in Salt -- One or more exploratory holes into the salt formation (if required). One or more exploratory/disposal wells into potential brine disposal aquifers (as required). When subsurface conditions are well known, the development holes can be treated as exploration holes.
   - Aquifer Storage Reservoirs -- May require many exploratory holes of various sizes to adequately define both the areal limits and stratigraphic conditions. Some of these holes can subsequently be used for monitoring or other operating functions.

   Borehole logging -- Subsurface geophysical surveys.

   Formation Pressure Testing -- Determination of water (and air) permeability of the aquifer, cap rock, and other underlying and overlying formations.

   Pumpdown Testing -- Determination of aquifer characteristics and cap rock permeability.

   Geologic Core Analysis -- Descriptive logging of cores for geologic and engineering character of the penetrated rock formations. Systematic sampling for laboratory analysis.

   Laboratory Testing -- Determination of critical physical characteristics related to mining/engineering or reservoir behavior (porosity, permeability, compressive strength).

   Detailed surface Mapping -- Determination of geology, hydrology and drainage, land use, etc.

4. Data Evaluation

   Upon completion of the field work and laboratory testing, the dai can be analyzed and synthesized for inclusion in a final feasibility report, and/or for defining needed additional research.

5. Feasibility Report

The final report will state the conclusions and recommendations of the researchers, a description of the study tasks, and the results of each investigation.

Table C-1 provides an evaluation of various techniques involved in the exploratory study and is an expansion of the categories given in Figure C-1. These charts explain in detail the work, data, or definition required under each category of Figure C-1.

Table C-1: DEFINITION OF ITEMS ON FIGURE C-1 (Sheet 1 of 16)

CONDITIONS	PRELIMINARY STUDIES		GEOLOGIC MAPPING	
	INFORMATION SEARCH	PRELIMINARY SITE INSPECTION	BY REMOTE SENSING	DIRECT SURFACE MAPPING
1. SITE SELECTION	RECONNAISSANCE.	RECONNAISSANCE.	RECONNAISSANCE.	RECONNAISSANCE AND DETAILED INVESTIGATION.
2. ENGINEERING APPLICATION	DETERMINE GENERAL GEOLOGICAL CONDITIONS OF AREA TO PLAN WHAT INFORMATION AND FUTURE EXPLORATION WORK IS REQUIRED.	DETERMINE EXISTING STATUS OF AREA, VIEW GENERAL GEOLOGICAL CONDITIONS FIRST HAND	PREPARATION OF TOPOGRAPHIC MAPS, IDENTIFICATION OF GEOLOGIC STRUCTURES AND SOIL AND ROCK TYPES, AND DETERMINATION OF HYDROLOGIC CONDITIONS.	DETERMINE GEOLOGIC STRUCTURE OF AREA, LOCATE SURFACE STRUCTURAL FEATURES, MAKE PICTORIAL REPRESENTATION OF AREA GEOLOGY. PREDICT SUBSURFACE CONDITIONS.
3. GEOLOGICAL ENVIRONMENT	ANY.	ANY.	ANY.	ANY.
4. PRINCIPLE USED	REVIEW OF ALL PREVIOUSLY RECORDED PERTINENT INFORMATION AVAILABLE ABOUT AREA.	VISUAL OBSERVATION.	DIFFERENT MATERIALS EXHIBIT DIFFERENT ELECTROMAGNETIC CHARACTERISTICS.	MEASUREMENT OF EXPOSED GEOLOGICAL FEATURES.
5. QUANTITIES MEASURED	ALL PERTINENT DATA OBTAINED.	MAJOR EXPOSED GEOLOGICAL AND SURFACE FEATURES ROUGHLY OR APPROXIMATELY NOTED.	ENERGY EMITTED AND REFLECTED FROM THE GROUND SURFACE AT WAVELENGTHS THROUGHOUT THE ELECTROMAGNETIC SPECTRUM.	ORIENTATION AND SIZE OF EXPOSED GEOLOGICAL STRUCTURAL FEATURES, ORIENTATION OF GEOLOGIC CONTACTS.
6. QUANTITIES COMPUTED FROM MEASUREMENTS	TENTATIVE CONCLUSIONS BASED UPON AMOUNT AND QUALITY OF INFORMATION OBTAINED.	FORMULATE DETAILED PLAN FOR FUTURE EXPLORATION WORK.	RELATIVE ELEVATIONS FROM PHOTOS. IN OTHER METHODS QUANTITIES COMPUTED ARE INTERMEDIATE FOR COMPARISONS, FINAL RESULTS ARE IDENTIFICATION OF MATERIALS AND FEATURES.	LATERAL AND VERTICAL PROJECTION OF EXPOSED STRUCTURAL FEATURES, AND SOIL AND ROCK UNITS.
7. COVERAGE	ALL POTENTIAL STORAGE SITES	SURFACE PROPERTY OVERLYING STORAGE INTERVAL.	DEPENDS UPON HEIGHT OF SENSING PLATFORM, AND LENS OR TYPE OF EQUIPMENT USED.	STRIP ALIGNMENT SUFFICIENTLY WIDE TO INCLUDE FEATURES NECESSARY TO ALLOW INTELLIGENT PROJECTION OF GEOLOGY AT DEPTH.
8. EFFECTIVE DEPTH	NOT APPLICABLE	SURFICIAL.	MOSTLY SURFICIAL BUT A FEW METHODS HAVE VARYING DEPTH PENETRATION.	SUBSURFACE PROJECTIONS (CRUDE).
9. LIMITATIONS	USUALLY ONLY FURNISHES GENERAL INFORMATION	INFORMATION OBTAINED IS NOT IN MUCH DETAIL AND MAY BE MISINTERPRETED.	GROUND CHECKING REQUIRED FOR POSITIVE MATERIAL IDENTIFICATION.	ONLY DEPICTS SURFACE EXPOSURE OF FEATURES WITH ACCURACY. MAP SCALE USED DETERMINES MINIMUM SIZE OF FEATURES SHOWN.
10. SENSITIVITY	DEPENDS UPON THOROUGHNESS OF INFORMATION OBTAINED	DEPENDS UPON COMPLEXITY OF GEOLOGY AND GEOGRAPHY IN AREA.	VARIABLE FROM METHOD TO METHOD.	DEPENDS UPON COMPLEXITY OF GEOLOGY IN AREA AND EXTENT OF EXPOSURE FOR STRUCTURAL FEATURES.
11. POSSIBLE ERRORS IN INTERPRETATION	NOT ALL PERTINENT FACTS MAY BE FURNISHED.	SUBSURFACE CONDITIONS CANNOT BE SEEN. COMPLEXITY OF GEOLOGY MAY NOT BE APPARENT.	INTERPRETATION MAY BE ATTEMPTED BEYOND THE DISCRIMINATION CAPABILITY OF A PARTICULAR METHOD. MISINTERPRETATION ALSO RESULTS FROM INEXPERIENCE.	INSUFFICIENT AREA MAPPED. NOT ALL PERTINENT FEATURES MAPPED IN SUFFICIENT DETAIL. LIMITED OUTCROPS MAY CAUSE MISINTERPRETATION.
12. PRINCIPAL INSTRUMENTS USED	MAPS, REPORTS, PHOTOGRAPHS, RECORDS, PROFESSIONAL PUBLICATIONS.	BRUNTON COMPASS, ROCK PICK, HAND LENS, CAMERA.	CAMERAS, OPTICAL-MECHANICAL SCANNERS, PASSIVE-MICROWAVE SCANNERS, RADAR, AND INFRARED AND MICROWAVE RADIOMETERS.	PLANE TABLE AND ALIDADE, COMPASS, TRANSIT, CAMERA.
13. ENERGY SOURCES	NOT APPLICABLE.	NOT APPLICABLE.	BATTERIES AND POWER FROM AIRCRAFT SYSTEMS.	NOT APPLICABLE.
14. CREW SIZE REQUIRED	ONE OR MORE.	ONE OR MORE.	2 TO 10.	2 TO 4.
15. TIME REQUIRED AND WORK ACCOMPLISHED	DEPENDS UPON SIZE AND COMPLEXITY OF AREA STUDIED AND UPON QUANTITY OF REFERENCE MATERIAL AVAILABLE.	GENERALLY LESS THAN ONE MAN-WEEK.	DATA ACQUISITION CAN COVER SEVERAL HUNDRED SQUARE MILES PER DAY. DATA REDUCTION AND INTERPRETATION ACCOUNT FOR THE MAJOR PORTION OF TIME CONSUMED.	DEPENDS UPON SIZE OF PROPERTY, AMOUNT OF EXPOSURES, COMPLEXITY OF GEOLOGY, SCALE OF MAPPING AND WEATHER.
16. COST	GENERALLY \$1,000-\$10,000.	GENERALLY \$500.00 - \$5,000.	DATA ACQUISITION FOR 15 SQUARE MILE AREA VARIES FROM \$1,000-\$15,000. INTERPRETATION OFTEN COSTS AS MUCH AS ACQUISITION.	DEPENDS UPON SIZE OF PROPERTY, AMOUNT OF EXPOSURES, COMPLEXITY OF GEOLOGY, SCALE OF MAPPING AND WEATHER.
17. POTENTIAL AREAS OF IMPROVEMENT	MORE DOCUMENTATION OF PREVIOUS WORK FOR EASY RETRIVAL BY OTHERS.	INSURE INVESTIGATOR HAS PROPER TRAINING AND EXPERIENCE.	BETTER DISCRIMINATION BETWEEN EARTH MATERIALS, INCREASED DEPTH PENETRATION OF INVESTIGATION.	MORE THOROUGH ATTENTION PAID TO DETAIL OF STRUCTURAL FEATURES, ESPECIALLY DISCONTINUITIES.

Table C-1: DEFINITION OF ITEMS ON FIGURE C-1 (Sheet 2 of 16)

CONDITIONS	GEOPHYSICAL			
	SEISMIC REFRACTION	SEISMIC REFLECTION	ELECTRICAL RESISTIVITY	MAGNETIC
1. SITE SELECTION STAGE	RECONNAISSANCE AND DETAILED INVESTIGATION.	RECONNAISSANCE AND DETAILED INVESTIGATION.	RECONNAISSANCE AND DETAILED INVESTIGATION.	RECONNAISSANCE.
2. ENGINEERING APPLICATION	DETERMINE DEPTH TO BEDROCK, WATER TABLE, AND UNWEATHERED ROCK. DETECT AND TRACE GEOLOGIC STRUCTURES AND BURIED CHANNELS. DETERMINE S-WAVE AND P-WAVE VELOCITIES FOR DERIVING ROCK PROPERTIES.	DETERMINE DEPTH TO VARIOUS STRATA AND CONTINUITY OF ROCK LAYERS. LOCATE DISCONTINUITIES. PROVIDE DATA ON STRATIGRAPHY.	DETERMINE DEPTH TO BEDROCK, VARIOUS STRATA AND WATER TABLE. LOCATE FAULT ZONES.	DETECT FAULTS AND CONTACTS. OUTLINE INTRUSIVE DIKES. LOCATE BURIED PIPELINES. OCCASIONALLY DETERMINE DEPTH OF WEATHERING AND DISTRIBUTION OF ALTERATION.
3. GEOLOGICAL ENVIRONMENT	ANY	PRIMARILY SEDIMENTARY ROCKS.	ANY, BUT PRIMARILY FOR OVERBURDEN.	ANY, BUT PRIMARILY IGNEOUS.
4. PRINCIPLE USED	DIFFERENCE IN SEISMIC-WAVE VELOCITIES THROUGH MEDIA OF DIFFERENT DENSITIES.	DIFFERENCE IN SEISMIC-WAVE VELOCITIES THROUGH MEDIA OF DIFFERENT DENSITIES.	DIFFERENCES IN ELECTRICAL RESISTIVITY OR CONDUCTIVITY OF INDIVIDUAL STRATA.	DIFFERENCES IN MAGNETIC FIELD INTENSITIES BETWEEN READING STATIONS.
5. QUANTITIES MEASURED	SEISMIC-WAVE TRAVEL TIME BETWEEN ENERGY SOURCE AND GEOPHONES, DISTANCE BETWEEN ENERGY SOURCE AND GEOPHONES AND DISTANCE BETWEEN GEOPHONES. ACCURATE TO ± 0.0005 TO 0.002 SECONDS = ± 5 TO 25 FEET.	SEISMIC-WAVE TRAVEL TIME BETWEEN ENERGY SOURCE AND GEOPHONES, DISTANCE BETWEEN ENERGY SOURCE AND GEOPHONES, AND DISTANCE BETWEEN GEOPHONES. ACCURATE TO ± 0.0005 TO 0.002 SECONDS = ± 5 TO 25 FEET DECREASING WITH DEPTH.	CURRENT INPUT, POTENTIAL DIFFERENCE, AND ELECTRODE SPACING. MEASURES FROM 0.003 TO 10,000 OHMS WITH ACCURACY OF ± 0.2 OHMS GENERALLY.	MAGNETIC FIELD INTENSITY. ACCURATE TO ± 1 GAMMA FOR TOTAL FIELD, 2.5 TO 10 GAMMA FOR VERTICAL FIELD, AND ± 10 GAMMA FOR HORIZONTAL FIELD.
6. QUANTITIES COMPUTED FROM MEASUREMENTS	SEISMIC-WAVE (USUALLY P-WAVE) VELOCITIES AND DEPTHS TO REFRACTING STRATA.	SEISMIC-WAVE VELOCITIES AND DEPTHS TO REFLECTING SURFACES.	APPARENT RESISTIVITY.	NONE DIRECTLY, BUT MAGNETIC EFFECT HAS SHAPE IN PLAN INDICATIVE OF DEPTH TO CAUSING BODY.
7. COVERAGE	LINEAR AT ANY DESIRED HORIZONTAL SPACING	LINEAR AT ANY DESIRED HORIZONTAL SPACING.	LINEAR, BOTH LATERALLY AND VERTICALLY.	POINT.
8. EFFECTIVE DEPTH	UP TO 500 ± FEET. GREATER DEPTH REQUIRES EXCESSIVE HORIZONTAL SPREAD.	GREATER THAN 500 ± FEET.	UP TO 3000+ FEET BUT USUALLY LESS THAN 100 FEET. DEPENDS UPON ELECTRODE SPACING AND POWER INPUT.	NOT SELECTIVE, BUT FIELD STRENGTH DECREASES AS SQUARE OF THE DISTANCE.
9. LIMITATIONS	VERTICAL VELOCITY CALIBRATION REQUIRED FOR DEPTH DETERMINATIONS. SEISMIC-WAVE VELOCITIES OF SUCCESSIVE STRATA MUST INCREASE WITH DEPTH. SOME BOREHOLES REQUIRED FOR CORRELATION.	VERTICAL VELOCITY CALIBRATION REQUIRED FOR DEPTH DETERMINATION. SOME BOREHOLES REQUIRED FOR CORRELATION.	A HIGH RESISTIVITY CONTRAST BETWEEN THE MATERIALS BEING LOCATED IS REQUIRED. STRATEGICALLY LOCATED BOREHOLES REQUIRED FOR REFERENCE.	DOES NOT PROVIDE DIRECT EVIDENCE OF ROCK GEOMETRY. DIFFERENCE IN MAGNETIC INTENSITIES FOR THE MATERIALS BEING LOCATED IS REQUIRED. CAN NOT BE USED NEAR EXTRANEOUS MAGNETIC MATERIALS.
10. SENSITIVITY	POOR RESULTS FOR STEEPLY DIPPING STRATA. THIN STRATA LAYERS MAY BE MISSED.	THIN STRATA LAYERS MAY BE MISSED.	RESULTS OFTEN AMBIGUOUS. IS A FUNCTION OF THE CURRENT SOURCE POWER CAPABILITY, SENSITIVITY OF THE MEASURING CIRCUIT, AND THE MOISTURE CONTENT AND/OR THE SALINITY OR FREE ION CONTENT OF THE CONATE MOISTURE.	IS A FUNCTION OF A MATERIALS MAGNETIC SUSCEPTIBILITY AND THE VARIATION WITH TIME OF THE EARTH'S NATURAL MAGNETIC FIELD. GROUND SURVEY READINGS ARE 25 TO 50 TIMES MORE ACCURATE THAN AIRBORNE READINGS.
11. POSSIBLE ERRORS IN INTERPRETATION	CAN NOT DISTINGUISH BETWEEN STRATA HAVING SIMILAR SEISMIC-WAVE VELOCITIES. LATERAL VARIATIONS IN STRATA COMPOSITION.	VARIATIONS IN STRATA COMPOSITION. READINGS CAN BE OBSCURED BY EARLIER ARRIVAL OF REFRACTED WAVES FROM OVERLYING STRATA.	VARIATIONS IN STRATA COMPOSITION.	INSUFFICIENT KNOWLEDGE OF THE MAGNETIC SUSCEPTIBILITY FOR THE VARIOUS ROCK UNITS AND OF THE REMANENT MAGNETIZATION PRESENT.
12. PRINCIPAL INSTRUMENTS USED	ELECTROMAGNETIC, VARIABLE RELUCTANCE, CAPACITATIVE, OR PIEZOELECTRIC GEOPHONES: AMPLIFIERS; AND OSCILLOGRAPH OR RECORDING UNIT.	ELECTROMAGNETIC, VARIABLE RELUCTANCE, CAPACITATIVE, OR PIEZOELECTRIC GEOPHONES: AMPLIFIERS; AND OSCILLOGRAPH OR RECORDING UNIT.	ELECTRICAL RESISTIVITY METER, MILLIAMPMETER, POTENTIAL MEASURING DEVICE.	DIP NEEDLE, MAGNETIC BALANCE (SCHMIDT MAGNETOMETER), FLUXGATE MAGNETOMETER, OR PROTON MAGNETOMETER.
13. ENERGY SOURCES	EXPLOSIVES, IMPACTORS, OR VIBRATORS.	EXPLOSIVES, IMPACTORS, OR VIBRATORS.	REVERSIBLE DIRECT OR LOW-FREQUENCY ALTERNATING ELECTRICAL CURRENT USUALLY SUPPLIED BY HEAVY-DUTY, DRY-CELL BATTERIES.	NATURAL MAGNETIC FORCES.
14. CREW SIZE REQUIRED	2 FOR SINGLE CHANNEL, 2 TO 7 FOR MULTI-CHANNEL, 15 TO 20 FOR VIBROSEIS.®	2 FOR SINGLE CHANNEL, 15 TO 20 FOR VIBROSEIS.®	A GEOPHYSICIST PLUS 1 TO 4 ASSISTANTS FOR MOVING ELECTRODES.	2 TO 3.
15. TIME REQUIRED AND WORK ACCOMPLISHED	5 TO 20 DEPTH DETERMINATIONS PER DAY WITH DEPTHS TO 500 FEET.	3 TO 15 DEPTH DETERMINATIONS PER DAY WITH DEPTHS GREATER THAN 500 FEET.	5 TO 20 DEPTH DETERMINATIONS PER DAY WITH DEPTHS TO 500 FEET.	WITH MAGNETIC BALANCE, SEVERAL READINGS PER HOUR. WITH FLUXGATE, SURVEYED AS RAPIDLY AS ONE CAN WALK. WITH PROTON, 3 TO 10 SECONDS PER STATIONARY READING.
16. COST	$25 TO $75 PER DEPTH DETERMINATION WITH PORTABLE EQUIPMENT, $100 TO $ 150 PER DEPTH DETERMINATION WITH VIBROSEIS.	$50 TO $75 PER DEPTH DETERMINATION WITH PORTABLE EQUIPMENT, $100 TO $150 PER DEPTH DETERMINATION WITH VIBROSEIS.	$500 TO $600 PER PROFILE-MILE.	$100 TO $150 PER PROFILE-MILE.
17. POTENTIAL AREAS OF IMPROVEMENT	DATA PROCESSING AND INTERPRETATION.	DATA PROCESSING AND INTERPRETATION.	DATA PROCESSING AND INTERPRETATION.	DATA PROCESSING AND INTERPRETATION.

Table C-1: DEFINITION OF ITEMS ON FIGURE C-1 (Sheet 3 of 16)

CONDITIONS	GEOPHYSICAL			
	ELECTROMAGNETIC	GRAVITY	RADIOMETRIC	ACOUSTICAL HOLOGRAPHY
1. SITE SELECTION STAGE	RECONNAISSANCE.	RECONNAISSANCE.	RECONNAISSANCE.	RECONNAISSANCE.
2. ENGINEERING APPLICATION	LOCATE AQUIFERS, BURIED PIPELINES, UTILITY LINES. OUTLINE INTRUSIVE DIKES. DETERMINE DEPTH TO BEDROCK.	MEASURE LATERAL CHANGES IN ROCK TYPES. DETERMINE DEPTH TO BEDROCK. LOCATE SOLUTION CHANNELS AND CAVITIES, HELP DETERMINE ALLUVIAL AQUIFER POROSITY.	LOCATE AREAS OF ABNORMALLY HIGH RADIATION. DISTINGUISH ROCKS HAVING DIFFERENT RADIOACTIVITY. CAN YIELD DATA ON SHALE CONSTITUENCY.	LOCATE DISCONTINUITIES IN GEOLOGIC STRUCTURE.
3. GEOLOGICAL ENVIRONMENT	ANY.	ANY	ANY.	ANY, BUT GENERALLY ROCK.
4. PRINCIPLE USED	DETECTION OF SECONDARY MAGNETIC FIELD OCCURRING IN PARTICULAR MATERIAL AS RESULT OF ARTIFICALLY-GENERATED, ALTERNATING-ELECTROMAGNETIC FIELD.	DIFFERENCES IN DENSITIES OF SUBSURFACE MATERIALS AS INDICATED BY LATERAL CHANGES IN THE EARTH'S GRAVITATIONAL FIELD.	DETECTION OF GAMMA-RAY RADIATION.	OPTICAL DIFFERENCES BETWEEN ACOUSTIC AND CARRIER WAVE INTENSITIES.
5. QUANTITIES MEASURED	AMPLITUDE AND PHASE ANGLE, OR PORTIONS IN- AND OUT-OF-PHASE WITH THE SOURCE CURRENT, OF SECONDARY FIELD COMPONENTS RELATIVE TO SOURCE. OR DIRECTION OF SECONDARY FIELD AT RECEIVER (DIP ANGLE PROCEDURE).	FORCE OF GRAVITY IN GRAVITY UNITS. ACCURATE TO ± 0.0000001 GALS.	INTENSITY OF RADIATION, OR RATE OF GAMMA RAY PRODUCTION, IN MILLIROENTGENS PER HOUR AT UP TO 4000+ COUNTS PER SECOND.	AMPLITUDE OF GENERATED AND RECEIVED SIGNALS, ELAPSED TIME BETWEEN TIME OF GENERATION AND RECEIPT OF ECHO.
6. QUANTITIES COMPUTED FROM MEASUREMENTS	READINGS ARE PLOTTED AND RESULTING CURVES INTERPRETED.	NONE DIRECTLY, BUT READINGS ARE CORRECTED FOR INSTRUMENT DRIFT, LATTITUDE AND ELEVATION CHANGES FROM A DATUM, AND TOPOGRAPHIC RELIEF.	NONE DIRECTLY, BUT VARIANCE ABOVE NORMAL BACKGROUND COUNT IS EVALUATED.	DISTANCE BETWEEN SOURCE AND DISCONTINUITY.
7. COVERAGE	POINT.	SPHERICAL AROUND A POINT.	POINT.	LINEAR.
8. EFFECTIVE DEPTH	UP TO 150 FEET WITH MOVING-SOURCE AND TO 1000 FEET WITH FIXED-SOURCE EQUIPMENT.	UP TO 3000+ FEET, BUT SIGNAL INTENSITY DECREASES AS SQUARE OF THE DEPTH.	SURFICIAL.	UP TO 500+ FEET, BUT SIGNAL INTENSITY DECREASES AS SQUARE OF THE DISTANCE.
9. LIMITATIONS	HAS RESTRICTED APPLICATIONS. DEPENDS UPON THE METHOD (MOVING OR FIXED SOURCE) USED. DEPENDS UPON THE PRESENCE OF A CONDUCTIVE MATERIAL.	DOES NOT PROVIDE A DIRECT MEASUREMENT OF ROCK GEOMETRY. REQUIRES KNOWING DENSITIES OF ROCK TYPES PRESENT FOR INTERPRETATION OF READINGS.	ONLY MEASURES SURFICIAL MANIFESTATIONS. DOES NOT DISCRIMINATE BETWEEN SOURCES OF RADIATION.	METHOD IS STILL IN AN EXPERIMENTAL STAGE OF DEVELOPMENT.
10. SENSITIVITY	RESULTS OFTEN AMBIGUOUS. IS A FUNCTION OF THE CURRENT SOURCE POWER CAPABILITY, SENSITIVITY OF THE MEASURING DEVICE, FREQUENCY OF THE INPUT POWER, AND SEPARATION DISTANCE BETWEEN TRANSMITTER AND RECEIVER.	DEPENDS UPON DENSITY CONTRASTS BETWEEN GEOLOGIC UNITS IN A HORIZONTAL DIRECTION.	DEPENDS UPON SIZE AND QUALITY OF RADIATION SOURCE AND DEGREE OF RADIOACTIVITY OF THE OVERBURDEN.	RESULTS CAN BE AMBIGUOUS. RESOLUTION DEPENDS UPON DISTANCE BETWEEN ANOMALY AND INSTRUMENT PACKAGE. DETECTION DEPENDS UPON ANOMALY SIZE AND DISTANCE AWAY FROM THE INSTRUMENT PACKAGE.
11. POSSIBLE ERRORS IN INTERPRETATION	IMPROPER COMPARISON OF FIELD DATA CURVES WITH REFERENCE CURVES. INACCURATE PLOTTING OF CURVES.	POSITION AT READING POINTS NOT DETERMINED WITH SUFFICIENT ACCURACY.	LOCAL GEOLOGY IMPROPERLY EVALUATED. GROUND WATER LEACHING EFFECTS NOT CONSIDERED SUFFICIENTLY.	CAN NOT DETERMINE THE TYPE OF DISCONTINUITY.
12. PRINCIPAL INSTRUMENTS USED	INDUCTION MAGNETOMETER, AMPLIFIER, HEADPHONES, AND INCLINOMETER FOR MEASURING DIP ANGLE.	SWINGING PENDULUM (GENERALLY USED FOR LABORATORY-TYPE DETERMINATIONS), GRAVITY METER (MOST WIDELY USED FIELD INSTRUMENT), OR TORSION BALANCE.	SCINTILLOMETER OR GAMMA-RAY SPECTROMETER.	TRANSMITTING AND RECEIVING TRANSDUCERS, ELECTRONIC SIGNAL PROCESSOR, AND RECONSTRUCTION DISPLAY DEVICE.
13. ENERGY SOURCES	PASSIVE USES RADIATION FROM VLF STATIONS. ACTIVE USES PORTABLE TRANSMITTER GENERATING ALTERNATING ELECTRICAL CURRENT.	EARTH'S GRAVITATIONAL FIELD.	NATURAL RADIOACTIVITY.	VIBRATOR OR EXPLOSIVES.
14. CREW SIZE REQUIRED	ONE FOR PASSIVE POWER SOURCE. 2 TO 4 WHEN USING A TRANSMITTER.	ONE GEOPHYSICIST PLUS TWO OR THREE, 3- OR 4-MAN, SURVEY CREWS.	ONE.	ONE GEOPHYSICIST PLUS 2 TO 10 ASSISTANTS.
15. TIME REQUIRED AND WORK ACCOMPLISHED	CREW OF 2 OR 3 CAN TRAVERSE 3 TO 6 MILES PER DAY TAKING READINGS AT 75- TO 100-FOOT INTERVALS. FIXED SOURCE EQUIPMENT REQUIRES AN ADDITIONAL 0.1 TO 0.5 THE TOTAL FIELD TIME FOR SETTING UP THE SOURCE.	SWINGING PENDULUM, 30+ MINUTES PER DETERMINATION. GRAVITY METER, 50+ READINGS PER DAY. TORSION BALANCE, ONLY A FEW READINGS PER DAY.	AS RAPIDLY AS TERRAIN CAN BE TRAVERSED.	NOT ESTABLISHED STILL IN EXPERIMENTAL STAGE OF DEVELOPMENT.
16. COST	ABOUT $75 TO $175 PER LINE MILE.	$350 TO $1,200 PER PROFILE MILE FOR SURVEYING AND GRAVITY READINGS.	$20 TO $40 PER LINE-MILE FOR A GROUND SURVEY.	HIGH, BUT NOT ESTABLISHED. STILL IN EXPERIMENTAL STAGE OF DEVELOPMENT.
17. POTENTIAL AREAS IMPROVEMENT	DATA PROCESSING AND INTERPRETATION.	DATA PROCESSING AND INTERPRETATION.	DATA PROCESSING AND INTERPRETATION.	RESOLUTION AND RECONSTRUCTION OF SUBSURFACE FEATURE IMAGES.

Table C-1: DEFINITION OF ITEMS ON FIGURE C-1 (Sheet 4 of 16)

CONDITIONS	SAMPLING			
	SURFACE	DRILLING EQUIPMENT	DISTURBED SAMPLES	UNDISTURBED SOIL SAMPLES, OPEN TUBE
1. SITE SELECTION STAGE	RECONNAISSANCE.	DETAILED INVESTIGATION.	DETAILED INVESTIGATION.	DETAILED INVESTIGATION.
2. ENGINEERING APPLICATION	IDENTIFICATION OF MATERIAL AND OBTAIN SAMPLES FOR LABORATORY TESTING.	OBTAIN ACCESS FOR SAMPLING. ALLOW USE OF BOREHOLE LOGGING TECHNIQUES. FIELD OBSERVATION OF IN-SITU CONDITIONS. OBTAIN PROFILE OF SUBSURFACE MATERIAL.	IDENTIFICATION AND CLASSIFICATION OF MATERIAL. OBTAIN SAMPLES FOR LABORATORY TESTING.	OBTAIN SAMPLES HAVING MINIMAL DISTURBANCE FOR LABORATORY TESTING.
3. GEOLOGICAL ENVIRONMENT	ANY.	SOIL FOR AUGER DRILL AND WASH BORING. SOIL AND SOFT ROCK FOR CHURN DRILL. SOIL AND ROCK FOR ROTARY DRILL.	ANY.	FRIABLE, PARTIALLY DRY SILTS AND CLAYS.
4. PRINCIPLE USED	VISUAL OBSERVATION.	VARIOUS DRILLING TECHNIQUES, CORING AND NON-CORING.	SAMPLER DRIVEN INTO GROUND AND THEN WITHDRAWN WITH SAMPLE FOR SOILS. COLLECTION OF DRILL CUTTINGS.	SAMPLER PUSHED INTO GROUND AND THEN WITHDRAWN WITH SAMPLE.
5. QUANTITIES MEASURED	COMPOSITION, TEXTURE, STRUCTURE, WEATHERING, ALTERATION, FOLIATION, POROSITY, HARDNESS, INDURATION, CEMENTATION.	DRILL BIT ROTATIONAL SPEED (IF APPLICABLE) AND ADVANCE RATE, CIRCULATING FLUID DENSITY, FLOW RATE AND GAIN OR LOSS, DEPTH DRILLED, WEIGHT OR PRESSURE APPLIED TO THE BIT, BIT WEAR.	FORCE REQUIRED TO DRIVE SAMPLER IN SOILS. SIZE OF CUTTINGS.	FORCE REQUIRED TO PUSH SAMPLER.
6. QUANTITIES COMPUTED FROM MEASUREMENTS	PHYSICAL AND MECHANICAL PROPERTIES IF SAMPLES ARE LABORATORY TESTED.	DRILLING RATE, SPECIFIC ENERGY REQUIRED TO DRILL, COMPRESSIVE STRENGTH OF ROCK INDIRECTLY.	NONE, BUT AN INDICATION OF GROUNDS PENETRATION RESISTANCE IS OBTAINED.	NONE, BUT AN INDICATION OF GROUNDS PENETRATION RESISTANCE IS OBTAINED.
7. COVERAGE	POINT.	LINEAR WITH DEPTH.	LINEAR ALONG THE SAMPLER AXIS.	LINEAR ALONG THE SAMPLER AXIS.
8. EFFECTIVE DEPTH	SURFICIAL.	UP TO 30,000+ FEET FOR ROTARY, TO BEDROCK FOR CHURN, TO 200 FEET FOR AUGER, AND TO 100 FEET FOR WASH BORING.	TO BEDROCK FOR SOILS. UP TO 30,000+ FEET FOR ROCK.	SURFICIAL.
9. LIMITATIONS	GIVES PRELIMINARY AND APPROXIMATE INFORMATION ONLY. ROCK SAMPLE AVAILABILITY RESTRICTED TO OUTCROPS AND SURFACE FLOAT. GEOCHEMICAL SAMPLING RESTRICTED TO AREAS COVERED BY RESIDUAL SOIL.	ACCESSIBILITY TO DRILLING SITE. EACH METHOD NOT APPLICABLE TO ALL CONDITIONS.	SOIL CANNOT CONTAIN APPRECIABLE AMOUNTS OF LARGE-SIZE GRAVEL AND NEEDS SUFFICIENT COHESION TO REMAIN IN THE SAMPLER DURING WITHDRAWAL.	UNSUITABLE FOR SOILS TOO HARD TO PERMIT SMOOTH PENETRATION AND SOILS CONTAINING GRAVEL THAT WILL DAMAGE THE TUBE OR SAMPLE.
10. SENSITIVITY	DEPENDS UPON QUALITY OF SAMPLES OBTAINED.	DEPENDS UPON OPERATORS SKILL AND EXPERIENCE.	DEPENDS ON DEPTH FROM WHICH SAMPLE IS OBTAINED AND STABILITY OF BOREHOLE WALL.	DEPENDS ON CORE TAKEN TO AVOID SAMPLE DISTURBANCE
11. POSSIBLE ERRORS IN INTERPRETATION	SAMPLES MAY NOT BE INDICATIVE OF THE MATERIAL IN SITU AND/OR AT DEPTH.	CAN DETECT ONLY MAJOR CHANGES IN STRATIGRAPHY AND CONDITIONS.	SAMPLE CONTAMINATED BY MATERIAL FROM ANOTHER STRATUM.	HOLE NOT PROPERLY CLEANED BEFORE TAKING SAMPLE
12. PRINCIPAL INSTRUMENTS USED	HAND LENS AND MICROSCOPE, PICKS, HAMMERS, SHOVELS.	ROTARY, CHURN (OR PERCUSSION), OR AUGER DRILLS; WASH BORING.	AUGER DRILLS AND OPEN-DRIVE, DISPLACEMENT, OR CABLE-TOOL SAMPLERS FOR SOILS.	SHELBY TUBE.
13. ENERGY SOURCES	NOT APPLICABLE.	GASOLINE OR DIESEL ENGINE, COMPRESSED AIR, HYDRAULIC, ELECTRICAL POWER, PUMPS.	DRILLING RIG DRIVE MECHANISM, HYDRAULIC OR MECHANICAL JACKS, HAMMERS.	MOST SATISFACTORY METHOD FOR PUSHING SAMPLER IS WITH DRIVE MECHANISM PREFERABLY HYDRAULIC) ON DRILL RIG.
14. CREW SIZE REQUIRED	ONE.	COMMONLY 2 OR 3.	COMMONLY 2.	COMMONLY 2.
15. TIME REQUIRED AND WORK ACCOMPLISHED	AS RAPIDLY AS TERRAIN CAN BE TRAVERSED, SAMPLES COLLECTED, AND OBSERVATIONS MADE AND RECORDED.	100 TO 600 FEET PER DAY IN SOIL, 20 TO 300 FEET PER DAY IN ROCK.	DEPENDS ON DEPTH OF SAMPLING AND/OR DRILLING RATE.	10 TO 30 MINUTES PER SAMPLE.
16. COST	MINIMAL.	\$5 TO \$20 PER FOOT.	UP TO \$20 PER SAMPLE.	ABOUT \$20 PER SAMPLE.
17. POTENTIAL AREAS OF IMPROVEMENT	OBTAIN BETTER REPRESENTATIVE SAMPLES.	INCREASED PENETRATION RATES.	REDUCE SAMPLE CONTAMINATION.	OBTAIN BETTER REPRESENTATIVE SAMPLES.

Table C-1: DEFINITION OF ITEMS ON FIGURE C-1 (Sheet 5 of 16)

CONDITIONS	UNDISTURBED SAMPLING		
	SOIL SAMPLES, PISTON TUBE.	SOIL SAMPLES, ROTARY CORE	ROCK SAMPLES, CORING
1. SITE SELECTION	DETAILED INVESTIGATION.	DETAILED INVESTIGATION.	DETAILED INVESTIGATION.
2. ENGINEERING APPLICATION	OBTAIN SAMPLES HAVING MINIMAL DISTURBANCE FOR LABORATORY TESTING.	OBTAIN SAMPLES HAVING MINIMAL DISTURBANCE FOR LABORATORY TESTING.	OBTAIN SAMPLES FOR LABORATORY TESTING. OBSERVATION OF IN-SITU ROCK CONDITIONS.
3. GEOLOGICAL ENVIRONMENT	SOILS.	HARD COHESIVE SOILS.	ROCK.
4. PRINCIPLE USED	SAMPLER PUSHED INTO GROUND AND THEN WITHDRAWN WITH SAMPLE	ANNULAR-TYPE HOLE DRILLED WITH RECOVERY OF RESULTING INNER CORE.	ANNULAR-TYPE HOLE DRILLED WITH RECOVERY OF RESULTING INNER CORE.
5. QUANTITIES MEASURED	FORCE REQUIRED TO PUSH SAMPLER.	DRILL BIT ROTATIONAL SPEED AND ADVANCE RATE; CIRCULATING FLUID DENSITY, FLOW RATE, AND LOSS OR GAIN; PERCENTAGE AND CHARACTERISTICS OF CORE RECOVERED; DEPTH DRILLED.	DRILL BIT ROTATIONAL SPEED, PRESSURE APPLIED, WEAR, AND ADVANCE RATE; CIRCULATING FLUID DENSITY, FLOW RATE, AND LOSS OR GAIN; PERCENTAGE AND CHARACTERISTICS OF CORE RECOVERED; DEPTH DRILLED.
6. QUANTITIES COMPUTED FROM MEASUREMENTS	NONE, BUT AN INDICATION OF GROUND PENETRATION RESISTANCE IS OBTAINED.	EMPIRICAL DESIGNATIONS FOR GROUND CLASSIFICATION FROM CORE RECOVERY, CONDITION, AND DEPTH.	EMPIRICAL DESIGNATIONS FOR GROUND CLASSIFICATION FROM CORE RECOVERY, CONDITION, AND DEPTH.
7. COVERAGE	LINEAR ALONG THE SAMPLER AXIS.	LINEAR ALONG THE BOREHOLE AXIS.	LINEAR ALONG THE BOREHOLE AXIS.
8. EFFECTIVE DEPTH	TO BEDROCK.	TO BEDROCK.	UP TO 30,000+ FEET.
9. LIMITATIONS	SOIL CANNOT CONTAIN APPRECIABLE AMOUNTS OF GRAVEL AND NEEDS SUFFICIENT COHESION TO REMAIN IN SAMPLER DURING WITHDRAWAL.	GROUND MUST BE COMPETENT WITHOUT VOIDS OR EXCESSIVE FRACTURING.	BADLY FRACTURED GROUND REQUIRES GROUTING, CASING, OR COSTLY DRILLING FLUID ADDITIVES.
10. SENSITIVITY	REQUIRES A SMOOTH CONTINUOUS PUSH AT A UNIFORM FAST RATE.	DEPENDS UPON THE ROTATIONAL SPEED AND ADVANCE RATE OF THE DRILL BIT, THE CIRCULATING FLUID TYPE AND FLOW RATE USED, AND THE AMOUNT OF CORE RECOVERY.	DEPENDS UPON KNOWLEDGE OF HOLE DIRECTION AND AMOUNT OF CORE RECOVERY.
11. POSSIBLE ERRORS IN INTERPRETATION	HOLE NOT PROPERLY CLEANED BEFORE TAKING SAMPLE.	MAY REACH WRONG CONCLUSIONS FOR REASONS OF LOW CORE RECOVERY.	MAY REACH WRONG CONCLUSIONS FOR REASONS OF LOW CORE RECOVERY. IMPROPER ORIENTATION OF CORE.
12. PRINCIPAL INSTRUMENTS USED	FIXED PISTON (SUCH AS HVORSLEV-TYPE, HONG, HYDRAULIC PISTON, OR SWEDISH FOIL SAMPLER), RETRACTABLE PISTON, FREE PISTON.	SINGLE- AND DOUBLE-TUBE CORE BARRELS.	SINGLE- AND DOUBLE-TUBE CORE BARRELS.
13. ENERGY SOURCES	MOST SATISFACTORY METHOD FOR PUSHING SAMPLER IS WITH DRIVE MECHANISM PREFERABLY HYDRAULIC) ON DRILL RIG.	DRILLING RIG.	DRILLING RIG.
14. CREW SIZE REQUIRED	COMMONLY 2.	2 TO 3.	2 TO 3.
15. TIME REQUIRED AND WORK ACCOMPLISHED	10 TO 30 MINUTES PER SAMPLE.	50 TO 200 FEET PER 8-HOUR SHIFT.	20 TO 100 FEET PER 8-HOUR SHIFT.
16. COST	$15 TO $20 PER SAMPLE.	$5 TO $7 PER FOOT DIRECT DRILLING COST. $15 TO $20 PER FOOT RUBBER SLEEVE.	$5 TO $20 PER FOOT DIRECT DRILLING COST.
17. POTENTIAL AREAS OF ROVEMENT	OBTAIN BETTER REPRESENTATIVE SAMPLES.	INCREASE PENETRATION RATES AND CORE RECOVERY.	INCREASE PENETRATION RATES AND CORE RECOVERY

Table C-1: DEFINITION OF ITEMS ON FIGURE C-1 (Sheet 6 of 16)

CONDITIONS	BOREHOLE LOGGING			
	VISUAL OR PHOTOGRAPHIC	SPONTANEOUS POTENTIAL	CONVENTIONAL RESISTIVITY	MICRORESISTIVITY
1. SITE SELECTION STAGE	DETAILED INVESTIGATION.	DETAILED INVESTIGATION.	DETAILED INVESTIGATION.	DETAILED INVESTIGATION.
2. ENGINEERING APPLICATION	VISUAL EXAMINATION OF BOREHOLE WALLS, DETERMINE ORIENTATION OF GEOLOGIC DISCONTINUITIES.	DETECT AND LOCATE BOUNDARIES OF PERMEABLE BEDS. CORRELATE STRATIGRAPHY BETWEEN BOREHOLES.	DETERMINE DEPTH TO BEDROCK, THICKNESS AND TYPE OF SEDIMENTARY LAYERS, PRESENCE AND SALINITY OF GROUND WATER, ROCK PERMEABILITY. CORRELATE STRATIGRAPHY BETWEEN BOREHOLES.	DELINEATE PERMEABLE FORMATIONS.
3. GEOLOGICAL ENVIRONMENT	ANY.	ANY, BUT PRIMARILY SEDIMENTARY.	ANY, BUT PRIMARILY SEDIMENTARY.	ANY, BUT PRIMARILY SEDIMENTARY.
4. PRINCIPLE USED	VISUAL OBSERVATION, TELEVISION AND STILL PHOTOGRAPHY.	POTENTIAL DIFFERENCE BETWEEN TWO ELECTRODES.	DIFFERENCE IN ELECTRICAL RESISTIVITY OR CONDUCTIVITY OF STRATA.	DIFFERENCE IN ELECTRICAL RESISTIVITY BETWEEN MUD CAKE AND FORMATION.
5. QUANTITIES MEASURED	ATTITUDES OF DISCONTINUITIES AND BEDDING PLANES.	DIFFERENCE IN POTENTIAL BETWEEN MOVING ELECTRODE IN BOREHOLE AND FIXED ELECTRODE ON GROUND SURFACE. DEPTH TO MOVING ELECTRODE.	CURRENT INPUT AND POTENTIAL DIFFERENCE BETWEEN TWO ELECTRODES AT FIXED SPACING WITHIN BOREHOLE. DEPTH TO READING POINT.	RESISTIVITY OF MUD CAKE AND FORMATION INVADED BY THE DRILLING MUD. DEPTH TO POINT OF READING.
6. QUANTITIES COMPUTED FROM MEASUREMENTS	NOT APPLICABLE.	PLOT OF THE SP CURVE WHICH GIVES LOCATION AND THICKNESS OF PERMEABLE BEDS.	APPARENT RESISTIVITY IN OHM-METERS. PLOT OF DEPTH VERSUS RESISTIVITY READINGS GIVES LOCATION AND THICKNESS OF DIFFERENT STRATA.	PLOT OF DEPTH VERSUS RESISTIVITY READINGS.
7. COVERAGE	CIRCULAR ABOUT A POINT AND LINEAR ALONG THE BOREHOLE AXIS.	ROUGHLY SPHERICAL.	ROUGHLY SPHERICAL.	ROUGHLY SPHERICAL.
8. EFFECTIVE DEPTH	PERISCOPE TO 100+ FEET, TELEVISION TO 4000 FEET, FILM-TYPE CAMERA TO 8000 FEET.	NOT APPLICABLE	DEPENDS ON ELECTRODE SPACING, BUT GENERALLY LESS THAN 20 FEET OUT FROM BOREHOLE.	VERY SHALLOW OUT FROM BOREHOLE WALL, LESS THAN 6 INCHES.
9. LIMITATIONS	HUMIDITY MAY FOG THE LENS, MUDDY WATER CAN RESTRICT VIEWING, SMALL HOLE SIZE MAY RESTRICT ENTRY.	BOREHOLE MUST CONTAIN A CONDUCTIVE FLUID. IS NOT SATISFACTORY FOR USE IN UNCASED HOLES.	BOREHOLE MUST CONTAIN A CONDUCTIVE FLUID. RESISTIVITY CONTRAST BETWEEN FORMATIONS REQUIRED. RESULTS OFTEN AMBIGUOUS. ONLY INDUCTION RESISTIVITY CAN BE RUN IN HIGHLY SALINE HOLE FLUIDS.	BOREHOLE MUST CONTAIN A CONDUCTIVE DRILLING MUD. HAS A SMALL, LIMITED DEPTH OF PENETRATION. POROSITIES MUST BE BETWEEN 12 AND 17%.
10. SENSITIVITY	DEPENDS UPON CLARITY OF BOREHOLE ATMOSPHERE AND CLEANLINESS OF BOREHOLE WALLS.	DEPENDS UPON INTENSITY OF ELECTRICAL CURRENT USED, THICKNESS OF PERMEABLE BEDS, DIAMETER OF BOREHOLE, AND INDIVIDUAL RESISTIVITIES OF THE VARIOUS FORMATIONS, MUD FILTRATE AND BOREHOLE FLUID.	IS FUNCTION OF POWER SOURCE CAPABILITY, SENSITIVITY OF MEASURING CIRCUIT, ELECTRODE SPACING, AND MUD CAKE THICKNESS.	IS FUNCTION OF POWER SOURCE CAPABILITY, SENSITIVITY OF MEASURING CIRCUIT, CHARACTER AND THICKNESS OF MUD CAKE, AND CHARACTER OF BOREHOLE WALL SURFACE.
11. POSSIBLE ERRORS IN INTERPRETATION	ORIENTATION OF CAMERA NOT KNOWN CORRECTLY.	DIFFERENCES IN RESISTIVITY AND THICKNESS OF SUCCESSIVE BEDS AFFECT INTERPRETATION. ANOTHER LOGGING TECHNIQUE USUALLY NECESSARY TO AID IN INTERPRETATION.	TYPICAL CURVE SHAPES MUST BE WELL KNOWN. EXTENT OF DRILLING MUD INVASION AND BED THICKNESS AFFECT INTERPRETATION.	EXTENT OF DRILLING MUD INVASION AND BED THICKNESS AFFECT INTERPRETATION.
12. PRINCIPAL INSTRUMENTS USED	PERISCOPE, TELEVISION, FILM-TYPE CAMERA.	RECORDING GALVANOMETER.	NORMAL, LATERAL, AND FOCUSED LATERAL DEVICES.	MICROLOG
13. ENERGY SOURCES	ELECTRICAL CURRENT.	ELECTRICAL CURRENT	ELECTRICAL CURRENT.	ELECTRICAL CURRENT.
14. CREW SIZE REQUIRED	ONE OPERATING TECHNICIAN.	1 OR 2.	1 OR 2.	1 OR 2.
15. TIME REQUIRED AND WORK ACCOMPLISHED	DEPENDS ON DEPTH AND METHOD USED.	ABOUT 15 MINUTES FOR A 500-FOOT HOLE, PLUS SET-UP.	ABOUT 15 MINUTES FOR A 500-FOOT HOLE, PLUS SET-UP.	ABOUT 30 MINUTES FOR A 500-FOOT HOLE PLUS SET-UP.
16. COST	$150 TO $200 PER DAY FOR CAMERA AND $175 TO $200 PER DAY FOR TECHNICIAN	$600 TO $800 PER 500-FOOT HOLE DIRECT COST WHEN RUN WITH ANOTHER LOG.	$600 TO $800 PER 500-FOOT HOLE DIRECT COST WHEN RUN WITH ANOTHER LOG.	$600 TO $800 PER 500-FOOT HOLE DIRECT COST WHEN RUN WITH ANOTHER LOG.
17. POTENTIAL AREAS OF IMPROVEMENT	GREATER AVAILABILITY AND BETTER CONTROL.	PORTABILITY FOR RUGGED TERRAIN.	PORTABILITY FOR RUGGED TERRAIN AND ADAPT FOR HORIZONTAL HOLES.	ADAPT FOR HORIZONTAL HOLES AND MINIATURIZATION.

Table C-1: DEFINITION OF ITEMS ON FIGURE C-1 (Sheet 7 of 16)

CONDITIONS	BOREHOLE LOGGING			
	FOCUSING ELECTRODE	INDUCTION	GAMMA RAY	NEUTRON
1. SITE SELECTION STAGE	DETAILED INVESTIGATION.	DETAILED INVESTIGATION.	DETAILED INVESTIGATION.	DETAILED INVESTIGATION.
2. ENGINEERING APPLICATION	DETECT AND LOCATE BOUNDARIES OF FORMATIONS HAVING MODERATE-TO-SMALL BED THICKNESSES.	DETERMINE SEQUENCE AND THICKNESS OF VARIOUS STRATA. LOCATE FORMATION BOUNDARIES.	DEFINE SHALE BEDS. DETECT AND EVALUATE RADIOACTIVE MINERALS. CORRELATE STRATIGRAPHY BETWEEN BOREHOLES.	DELINEATE POROUS FORMATIONS AND DETERMINE THEIR POROSITY. DETECT GAS. LITHOLOGY INTERPRETATION.
3. GEOLOGICAL ENVIRONMENT	ANY, BUT PRIMARILY SEDIMENTARY.	ANY, BUT PRIMARILY SEDIMENTARY.	ANY.	ANY, BUT PRIMARILY SEDIMENTARY.
4. PRINCIPLE USED	DIFFERENCE IN ELECTRICAL RESISTIVITY OF STRATA.	DIFFERENCE IN ELECTRICAL CONDUCTIVITY OF STRATA AS DETERMINED FROM CURRENT FLOW INDUCED BY A GENERATED, ALTERNATING MAGNETIC FIELD.	MEASUREMENT OF NATURAL RADIOACTIVITY.	COUNTING OF EITHER NEUTRONS AT A FIXED DISTANCE FROM THEIR SOURCE OR THE GAMMA RAYS EMITTED BY ATOMS CAPTURING THE RELEASED NEUTRONS.
5. QUANTITIES MEASURED	CURRENT INPUT AND POTENTIAL DIFFERENCE BETWEEN MOVING ELECTRODE IN BOREHOLE AND FIXED ELECTRODE ON GROUND SURFACE. DEPTH TO MOVING ELECTRODE.	CURRENT INPUT, INDUCED VOLTAGE.	COUNT OF GAMMA RAYS REACHING DETECTORS. LOGGING SPEED OF INSTRUMENT. DEPTH TO POINT OF READING.	COUNT OF NEUTRONS AND/OR GAMMA RAYS REACHING DETECTORS. LOGGING SPEED OF INSTRUMENT. DEPTH TO POINT OF READING.
6. QUANTITIES COMPUTED FROM MEASUREMENTS	PLOT OF DEPTH VERSUS RESISTIVITY READINGS.	PLOT OF DEPTH VERSUS CONDUCTIVITY.	PLOT OF DEPTH VERSUS GAMMA RAY COUNT.	PLOT OF NEUTRON AND/OR GAMMA RAY COUNT AND POROSITY VERSUS DEPTH.
7. COVERAGE	ROUGHLY SPHERICAL.	ROUGHLY SPHERICAL.	CIRCULAR ABOUT A POINT.	DISTANCE BETWEEN SOURCE AND DETECTOR ALONG BOREHOLE AXIS.
8. EFFECTIVE DEPTH	SHALLOW OUT FROM BOREHOLE WALL, ONE INCH TO 3 FEET.	LESS THAN [illegible] FEET OUT FROM BORCHOLE WALL.	SHALLOW OUT FROM BOREHOLE WALL, UP TO ABOUT ONE FOOT.	SHALLOW OUT FROM BOREHOLE WALL, UP TO ABOUT ONE FOOT.
9. LIMITATIONS	BOREHOLE MUST CONTAIN A CONDUCTIVE FLUID. RESISTIVITY CONTRAST BETWEEN FORMATIONS REQUIRED.	RESISTIVITY OF FORMATIONS SHOULD BE LESS THAN 100 OHM-METERS AND THE BOREHOLE CONDUCTIVITY SHOULD BE LOW. CAN BE USED IN AIR.	DOES NOT DISCRIMINATE BETWEEN RADIATION SOURCES.	CANNOT DIFFERENTIATE BETWEEN A GAS AND LOW POROSITY.
10. SENSITIVITY	IS FUNCTION OF MUD CAKE AND INVADED ZONE THICKNESSES, AND BOREHOLE DIAMETER.	DEPENDS UPON RELATIVE CONDUCTIVITY OF THE VARIOUS FORMATIONS.	DEPENDS UPON DISTANCE TO RADIATION SOURCE.	INSTRUMENT RESPONSE REFLECTS MOSTLY AMOUNT OF HYDROGEN IN THE FORMATION AND THUS INDICATES PRIMARILY THE LIQUID-FILLED POROSITY.
11. POSSIBLE ERRORS IN INTERPRETATION	EXTENT OF DRILLING MUD INVASION AFFECTS INTERPRETATION.	TOOL NOT PROPERLY CALIBRATED.	PRESENCE OF ELEMENTS HAVING HIGH ATOMIC NUMBERS WILL CHANGE THE ABSORPTIVE CHARACTERISTICS OF THE FORMATIONS.	PRESENCE OF HYDROCARBONS AND/OR CLAY IN THE FORMATIONS CAN AFFECT INTERPRETATION.
12. PRINCIPAL INSTRUMENTS USED	LATEROLOG, MICROLATEROLOG, PROXIMITY, AND SPHERICALLY FOCUSED LOGS.	COAXIAL TRANSMITTER AND RECEIVER COILS WITH A GALVANOMETER.	SCINTILLATION COUNTER.	GNT, SNP (SIDEWALL NEUTRON POROSITY) OR CNL (COMPENSATED NEUTRON LOG) TOOLS.
13. ENERGY SOURCES	ELECTRICAL CURRENT.	HIGH-FREQUENCY ALTERNATING CURRENT.	NATURAL RADIOACTIVITY.	PLUTONIUM-BERYLLIUM, AMERICIUM-BERYLLIUM, OR RADIUM-BERYLLIUM FOR THE RADIOACTIVE SOURCE.
14. CREW SIZE REQUIRED	1 OR 2	1 OR 2	1 OR 2.	1 OR 2.
15. TIME REQUIRED AND WORK ACCOMPLISHED	ABOUT 30 MINUTES FOR A 500-FOOT HOLE, PLUS SET-UP.	ABOUT 15 MINUTES FOR A 500-FOOT HOLE PLUS SET-UP.	ABOUT 30 MINUTES FOR A 500-FOOT HOLE PLUS SET-UP.	ABOUT 30 MINUTES FOR A 500-FOOT HOLE PLUS SET-UP.
16. COST	$600 TO $800 PER 500-FOOT HOLE DIRECT COST WHEN RUN WITH ANOTHER LOG.	$600 TO $800 PER 500-FOOT HOLE DIRECT COST WHEN RUN WITH ANOTHER LOG.	$500 TO $800 PER 500-FOOT HOLE DIRECT COST WHEN RUN WITH ANOTHER LOG.	$350 TO $650 PER 500-FOOT HOLE DIRECT COST WHEN RUN WITH ANOTHER LOG.
17. POTENTIAL AREAS OF IMPROVEMENT	ADAPT FOR USE IN HORIZONTAL HOLES.	ADAPT FOR USE IN HORIZONTAL HOLES AND MINIATURIZATION.	ADAPT FOR USE IN HORIZONTAL HOLES.	PORTABILITY FOR RUGGED TERRAIN.

Table C-1: DEFINITION OF ITEMS ON FIGURE C-1 (Sheet 8 of 16)

CONDITIONS	BOREHOLE LOGGING			
	FORMATION DENSITY	SONIC	GRAVITATIONAL	CALIPER
1. SITE SELECTION STAGE	DETAILED INVESTIGATION.	DETAILED INVESTIGATION.	DETAILED INVESTIGATION.	DETAILED INVESTIGATION.
2. ENGINEERING APPLICATION	DETERMINE POROSITY. DETECT GAS. EVALUATE COMPLEX LITHOLOGIES AND SHALEY SANDS. IDENTIFY MINERALS IN EVAPORITE DEPOSITS.	DETERMINE POROSITY WHEN THE LITHOLOGY IS KNOWN. CORRELATE LITHOLOGY BETWEEN BOREHOLES. AID TO INTERPRETING SEISMIC RECORDS AND DETERMINING ELASTIC CONSTANTS.	DETERMINE POROSITY.	DETERMINE GEOMETRY AND VOLUME OF BOREHOLE. INDICATE GEOLOGIC STRUCTURE. CORRECTION OF RAW DATA FROM OTHER LOGGING METHODS.
3. GEOLOGICAL ENVIRONMENT	ANY, BUT PRIMARILY SEDIMENTARY.	ANY.	ANY.	ANY.
4. PRINCIPLE USED	COUNTING OF GAMMA RAYS AT A FIXED DISTANCE FROM A SOURCE.	VELOCITY OF A SOUND WAVE THROUGH A FORMATION.	MEASUREMENT OF EARTH'S GRAVITATIONAL FIELD.	PHYSICAL MEASUREMENT OF BOREHOLE DIAMETERS.
5. QUANTITIES MEASURED	COUNT OF GAMMA RAYS REACHING DETECTORS. LOGGING SPEED OF INSTRUMENT. DEPTH TO POINT OF READING.	TRAVEL TIME FOR A COMPRESSIONAL SOUND WAVE TO TRAVERSE ONE FOOT OF A FORMATION AND TRAVERSING TIME OF INSTRUMENT THROUGH BOREHOLE.	CHANGES IN GRAVITATIONAL ATTRACTION. DEPTH TO POINT OF READING.	DIAMETER OF BOREHOLE IN SEVERAL DIRECTIONS; DEPTH TO POINT OF READING.
6. QUANTITIES COMPUTED FROM MEASUREMENTS	PLOT OF GAMMA RAY COUNT AND APPARENT BULK DENSITY VERSUS DEPTH.	PLOT OF SOUND WAVE AND INSTRUMENT TRAVEL TIMES VERSUS DEPTH. CALCULATION OF FORMATION POROSITY AND ELASTIC CONSTANTS FOR GROUND	AVERAGE BULK DENSITY OF THE GROUND.	VOLUME AND SHAPE OF BOREHOLE.
7. COVERAGE	DISTANCE BETWEEN SOURCE AND DETECTOR ALONG BOREHOLE AXIS.	LINEAR DISTANCE BETWEEN SONIC RECEIVERS ALONG BOREHOLE AXIS.	CIRCULAR ABOUT A POINT.	CIRCULAR ABOUT A POINT.
8. EFFECTIVE DEPTH	AT BOREHOLE WALL	AT BOREHOLE WALL.	UP TO 500 ± FEET OUT FROM THE BOREHOLE WALL.	TO BOREHOLE WALL.
9. LIMITATIONS	INSTRUMENT MUST BE CALIBRATED. CALIPER LOG ALSO REQUIRED.	CALIPER AND DENSITY LOGS ALSO REQUIRED	REQUIRES A DIFFERENCE IN ELEVATION BETWEEN READING POINTS.	CANNOT DETECT LOCAL PROTRUSIONS AND CAVITIES NOR AMOUNT OF HOLE DEVIATION.
10. SENSITIVITY	DEPENDS UPON THE CONTACT BETWEEN INSTRUMENT AND BOREHOLE WALL.	DEPENDS UPON RELATIVE SONIC CHARACTERISTICS OF FORMATIONS. THE PRESENCE OF SHALE, GAS, AND/OR FRACTURES MAY OBSCURE READINGS.	DEPENDS UPON DIFFERENCE IN GROUND MASS BETWEEN TWO DEPTHS.	DEPENDS UPON LOGGING SPEED AND TRUE ROUNDNESS OF BOREHOLE.
11. POSSIBLE ERRORS IN INTERPRETATION	PRESENCE OF HYDROCARBONS AND SHALE OR CLAY IN THE FORMATIONS CAN AFFECT INTERPRETATION.	LITHOLOGY NOT KNOWN IN SUFFICIENT DETAIL.	PRESENCE OF HIGH DENSITY OBJECT CAN AFFECT READINGS.	WALL ENLARGEMENTS MAY OCCUR BETWEEN CONTACT POINTS OF ARMS WITH BOREHOLE WALL AND THUS GO UNDETECTED.
12. PRINCIPAL INSTRUMENTS USED	FORMATION DENSITY COMPENSATED TOOL HAVING A GAMMA-RAY SOURCE AND TWO DETECTORS (ONE FOR SHORT SPACING AND ONE FOR LONG SPACING).	COMPENSATED VELOCITY TYPE HAVING TWO MAGNETOSTRICTION-TYPE TRANSMITTING AND TWO PIEZOELECTRIC RECEIVING TRANSDUCERS. 3-D VELOCITY TYPE HAVING ONE TRANSMITTING AND ONE RECEIVING TRANSDUCER.	BOREHOLE GRAVIMETER.	CALIPER TOOL.
13. ENERGY SOURCES	GAMMA-RAY RADIOACTIVE SOURCE.	ELECTRICAL CURRENT.	EARTH'S GRAVITATIONAL FIELD.	ELECTRICAL POWER TO OPERATE CALIPER ARMS.
14. CREW SIZE REQUIRED	1 OR 2.	1 OR 2.	1 OR 2.	1 OR 2.
15. TIME REQUIRED AND WORK ACCOMPLISHED	ABOUT 30 MINUTES FOR A 500-FOOT HOLE PLUS SET-UP.	ABOUT 30 MINUTES FOR A 500-FOOT HOLE PLUS SET-UP.	ABOUT 30 MINUTES FOR A 500-FOOT HOLE PLUS SET-UP.	ABOUT 30 MINUTES FOR A 500-FOOT HOLE PLUS SET-UP.
16. COST	$450 TO $600 PER 500-FOOT HOLE DIRECT COST WHEN RUN WITH ANOTHER LOG.	$400 to $600 PER 500-FOOT HOLE DIRECT COST WHEN RUN WITH ANOTHER LOG.	$400 TO $650 PER 500-FOOT HOLE DIRECT COST WHEN RUN WITH ANOTHER LOG.	$400 TO $650 PER 500-FOOT HOLE DIRECT COST WHEN RUN WITH ANOTHER LOG.
17. POTENTIAL AREAS OF IMPROVEMENT	ADAPT FOR USE IN HORIZONTAL HOLES AND MINIATURIZATION.	ADAPT FOR USE IN HORIZONTAL HOLES AND MINIATURIZATION	ADAPT FOR USE IN HORIZONTAL HOLES.	ADAPT FOR USE IN HORIZONTAL HOLES.

Table C-1: DEFINITION OF ITEMS ON FIGURE C-1 (Sheet 9 of 16)

CONDITIONS	BOREHOLE LOGGING	IN SITU TESTING	
	TEMPERATURE	STATE OF STRESS	GROUNDWATER HYDROLOGY
1. SITE SELECTION STAGE	DETAILED INVESTIGATION.	DETAILED INVESTIGATIONS.	DETAILED INVESTIGATIONS.
2. ENGINEERING APPLICATION	DETERMINE GROUND TEMPERATURES AND GEOTHERMAL GRADIENT.	DETERMINE MAGNITUDE AND DIRECTIONS OF THE PRINCIPAL GROUND STRESSES.	DETERMINE ABILITY OF A FORMATION TO CONDUCT FREE WATER, ESTIMATE QUANTITY OF WATER THAT MAY FLOW INTO CAVERN.
3. GEOLOGICAL ENVIRONMENT	ANY.	ANY, BUT PRIMARILY ROCK.	ANY.
4. PRINCIPLE USED	CHANGE IN RESISTANCE OF AN ELECTRICAL CIRCUIT DUE TO A TEMPERATURE CHANGE.	OVERCORING OF STRAIN GAGE LOCATION.	MEASUREMENT OF WATER FLOW AMOUNT THROUGH A SECTION OF GROUND.
5. QUANTITIES MEASURED	FLUID TEMPERATURE WITHIN BOREHOLE. DEPTH TO POINT OF READING.	CHANGE IN STRAIN.	VOLUME OF WATER PUMPED, WATER LEVELS IN OBSERVATION WELLS, DISTANCES BETWEEN WELLS, AND AQUIFER THICKNESS (IF IT IS A CONFINED AQUIFER) OR CHANGE IN WATER LEVEL AND ELAPSED TEST TIME.
6. QUANTITIES COMPUTED FROM MEASUREMENTS	GROUND TEMPERATURE AT PARTICULAR DEPTHS AND GEOTHERMAL GRADIENT.	STRESS RELIEF THAT CAUSED THE STRAIN CHANGE OBSERVED.	OVERALL COEFFICIENT OF PERMEABILITY FOR THE GROUND IN TEST AREA.
7. COVERAGE	POINT.	POINT.	SPHERICAL AROUND A POINT.
8. EFFECTIVE DEPTH	WITHIN BOREHOLE.	UP TO 200 FEET.	TO ANY PROPOSED CAVERN DEPTH.
9. LIMITATIONS	BOREHOLE MUST CONTAIN A LIQUID.	ONLY INDICATES STRESS RELIEF OCCURRING AFTER STRAIN GAGE PLACEMENT.	ONLY CONSIDERS STEADY-STATE FLOW CONDITIONS. APPLICABLE OVER A LIMITED VERTICAL GROUND INTERVAL.
10. SENSITIVITY	DEPENDS UPON THE ELAPSED TIME BETWEEN STOPPING LIQUID CIRCULATION AND TAKING READING, AND HEAT CONDUCTIVITY OF THE LIQUID.	DEPENDS ON CARE TAKEN TO OBTAIN READINGS.	GIVES BETTER ESTIMATION OF IN SITU CONDITIONS THAN DOES LABORATORY TESTS. DOES NOT INDICATE EFFECTS OF LONG PERIOD OR SEASONAL FLUCTUATIONS.
11. POSSIBLE ERRORS IN INTERPRETATION	AMOUNT OF HEAT FLOW BETWEEN THE GROUND AND BOREHOLE LIQUID NOT EVALUATED CORRECTLY.	CAN ONLY ESTIMATE ORIGINAL STRESS EXISTING BEFORE ACCESS MADE FOR GAGE PLACEMENT.	WATER TABLE IS ASSUMED TO BE HORIZONTAL AND AQUIFER THICKNESS IS TAKEN AS RELATIVELY CONSTANT. DOES NOT DIFFERENTIATE BETWEEN INDIVIDUAL FLOW ROUTES. VERY SLIGHT MUDDING OF HOLE CAN ALTER RESULTS.
12. PRINCIPAL INSTRUMENTS USED	THERMISTOR.	STRAIN GAGES OR INCLUSION STRESS METER.	PUMP AND WATER FLOW RATE METER FOR PUMPING TESTS. WATER LEVEL DIFFERENCE INDICATOR AND TIMER FOR OPEN-END TESTS.
13. ENERGY SOURCES	ELECTRICAL CURRENT.	NOT APPLICABLE.	ELECTRIC MOTORS, MOST GENERALLY, TO OPERATE PUMPS.
14. CREW SIZE REQUIRED	1 OR 2.	2 OR 3.	2 OR MORE.
15. TIME REQUIRED AND WORK ACCOMPLISHED	ABOUT 45 MINUTES FOR A 500-FOOT HOLE PLUS SET-UP.	4+ HOURS PER TEST.	2 TO 6 HOURS PER TEST USUALLY.
16. COST	\$300 TO \$400 PER 500-FOOT HOLE DIRECT COST WHEN RUN WITH ANOTHER LOG.	\$150 TO \$600 PER TEST.	VARIABLE UPON METHOD USED AND LENGTH OF TEST.
17. POTENTIAL AREAS OF IMPROVEMENT	ADAPT FOR USE IN HORIZONTAL HOLES.	DEVELOP IMPROVED TECHNIQUES.	DEVELOP IMPROVED TECHNIQUES.

Table C-1: DEFINITION OF ITEMS ON FIGURE C-1 (Sheet 10 of 16)

CONDITIONS	TRENCHES AND PILOT EXPLORATION TUNNELS	IN SITU TESTING		
		SOIL SHEARING STRENGTH	STATE OF STRESS	GROUND WATER HYDROLOGY
1. SITE SELECTION STAGE	DETAILED INVESTIGATION.	DETAILED INVESTIGATION.	DETAILED INVESTIGATIONS.	DETAILED INVESTIGATIONS.
2. ENGINEERING APPLICATION	OBTAIN SAMPLES FOR LABORATORY TESTING. OBTAIN FIRST-HAND INFORMATION ON POSSIBLE EXCAVATION DIFFICULTIES AND SUPPORT REQUIREMENTS. DETAILED EXAMINATION OF GROUND STRUCTURAL FRACTURES AND CONDITIONS.	DETERMINE THE IN SITU COHESIVE SHEARING STRENGTH OF SOIL.	DETERMINE MAGNITUDE AND DIRECTIONS OF THE PRINCIPAL GROUND STRESSES.	DETERMINE ABILITY OF A FORMATION TO CONDUCT FREE WATER, ESTIMATE QUANTITY OF WATER THAT MAY FLOW INTO TUNNEL.
3. GEOLOGICAL ENVIRONMENT	ANY.	SOIL.	ANY, BUT PRIMARILY ROCK.	ANY.
4. PRINCIPLE USED	NOT APPLICABLE.	MEASUREMENT OF TORSIONAL FORCE REQUIRED TO SHEAR A CYLINDRICAL SOIL SURFACE.	OVERCORING OF STRAIN GAGE LOCATION.	MEASUREMENT OF WATER FLOW AMOUNT THROUGH A SECTION OF GROUND.
5. QUANTITIES MEASURED	MAGNITUDE AND DIRECTIONS OF PRINCIPLE GROUND STRESSES, DISCONTINUITY ORIENTATION AND FREQUENCY, WATER INFLOW, GROUND TEMPERATURE.	APPLIED TORQUE, ANGULAR ROTATION, VANE GEOMETRY, AND FRICTIONAL RESISTANCE OF TESTING DEVICE COMPONENTS.	CHANGE IN STRAIN.	VOLUME OF WATER PUMPED, WATER LEVELS IN OBSERVATION WELLS, DISTANCES BETWEEN WELLS, AND AQUIFER THICKNESS (IF IT IS A CONFINED AQUIFER) OR CHANGE IN WATER LEVEL AND ELAPSED TEST TIME.
6. QUANTITIES COMPUTED FROM MEASUREMENTS	REQUIREMENTS FOR SUPPORT, PUMPING, AND LINING IN MAIN TUNNEL.	INDICATED SHEAR STRENGTH.	STRESS RELIEF THAT CAUSED THE STRAIN CHANGE OBSERVED.	OVERALL COEFFICIENT OF PERMEABILITY FOR THE GROUND IN TEST AREA.
7. COVERAGE	LINEAR.	POINT.	POINT.	SPHERICAL AROUND A POINT.
8. EFFECTIVE DEPTH	TRENCHES TO 20 FEET. TUNNELS AT ANY DEPTH,	TO BEDROCK, DEPENDS UPON TORQUE STRENGTH OF RODS	UP TO 200 FEET.	TO ANY PROPOSED TUNNEL DEPTH.
9. LIMITATIONS	TRENCHES LIMITED TO PORTAL AREAS. TUNNELS ARE COSTLY IN BOTH TIME AND MONEY.	NOT SUITABLE FOR STIFF CLAYS WHERE STRENGTH IS CONTROLLED BY FRACTURES OR SLICKINSIDES.	ONLY INDICATES STRESS RELIEF OCCURRING AFTER STRAIN GAGE PLACEMENT.	ONLY CONSIDERS STEADY-STATE FLOW CONDITIONS. APPLICABLE OVER A LIMITED VERTICAL GROUND INTERVAL.
10. SENSITIVITY	EXCELLENT ABILITY TO DETECT CHANGES IN GROUND CONDITIONS.	ERRATIC RESULTS OBTAINED IN SOFT SOILS CONTAINING GRAVEL, ETC.	DEPENDS ON CARE TAKEN TO OBTAIN READINGS.	GIVES BETTER ESTIMATION OF IN SITU CONDITIONS THAN DOES LABORATORY TESTS. DOES NOT INDICATE EFFECTS OF LONG PERIOD OR SEASONAL FLUCTUATIONS.
11. POSSIBLE ERRORS IN INTERPRETATION	INACCURATE EXTRAPOLATION OF DATA TO LARGER TUNNEL SIZE.	SOIL MAY HAVE BEEN REMOLDED PRIOR TO TESTING. RESULTS ARE ONLY INDICATIVE.	CAN ONLY ESTIMATE ORIGINAL STRESS EXISTING BEFORE ACCESS MADE FOR GAGE PLACEMENT.	WATER TABLE IS ASSUMED TO BE HORIZONTAL AND AQUIFER THICKNESS IS TAKEN AS RELATIVELY CONSTANT. DOES NOT DIFFERENTIATE BETWEEN INDIVIDUAL FLOW ROUTES. VERY SLIGHT MUDDING OF HOLE CAN ALTER RESULTS.
12. PRINCIPAL INSTRUMENTS USED	STRAIN GAGES, VISUAL OBSERVATIONS.	VANE SHEAR DEVICE.	STRAIN GAGES OR INCLUSION STRESS METER.	PUMP AND WATER FLOW RATE METER FOR PUMPING TESTS. WATER LEVEL DIFFERENCE INDICATOR AND TIMER FOR OPEN-END TESTS.
13. ENERGY SOURCES	NOT APPLICABLE.	TORQUE APPLIED EITHER BY HAND OR AN ELECTRIC MOTOR THROUGH A GEAR TRAIN.	NOT APPLICABLE.	ELECTRIC MOTORS, MOST GENERALLY, TO OPERATE PUMPS.
14. CREW SIZE REQUIRED	1 TO 3 FOR READINGS PLUS AN EXCAVATION CREW.	1 OR 2.	2 OR 3.	2 OR MORE.
15. TIME REQUIRED AND WORK ACCOMPLISHED	5 TO 50 FEET ADVANCE PER 24-HOUR DAY FOR 10-TO 12-FOOT TUNNEL.	5 TO 15 MINUTES PER TEST.	4+ HOURS PER TEST.	2 TO 6 HOURS PER TEST USUALLY.
16. COST	VARIABLE UPON TUNNEL SIZE AND GROUND CONDITIONS ENCOUNTERED.	ABOUT $5 PER TEST.	$100 TO $500 PER TEST.	VARIABLE UPON METHOD USED AND LENGTH OF TEST.
17. POTENTIAL AREAS OF IMPROVEMENT	FASTER ADVANCE RATES.	DEVELOP IMPROVED TECHNIQUES.	DEVELOP IMPROVED TECHNIQUES.	DEVELOP IMPROVED TECHNIQUES.

Table C-1: DEFINITION OF ITEMS ON FIGURE C-1 (Sheet 11 of 16)

CONDITIONS	LABORATORY TESTING OF SOIL			
	GRADATION	MOISTURE CONTENT	UNIT WEIGHT	POROSITY
1. SITE SELECTION STAGE	DETAILED INVESTIGATION.	DETAILED INVESTIGATION.	DETAILED INVESTIGATION.	DETAILED INVESTIGATION.
2. ENGINEERING APPLICATION	FOR CLASSIFICATION OF SOIL MATERIALS.	FOR CLASSIFICATION. AID IN EVALUATION OF POTENTIAL WATER PROBLEMS.	USED IN ENGINEERING DESIGN.	USED IN ENGINEERING DESIGN. INDICATION OF POSSIBLE PERMEABILITY FOR SOIL MASS.
3. GEOLOGICAL ENVIRONMENT	SOIL.	SOIL.	SOIL.	SOIL.
4. PRINCIPLE USED	MATERIAL PASSING THRU SCREENS. VELOCITY OF FREELY FALLING SPHERES.	DRYING OF SPECIMEN TO DETERMINE AMOUNT OF MOISTURE REMOVED.	RATIO OF A SAMPLES WEIGHT TO ITS VOLUME.	RATIO OF VOID VOLUME TO TOTAL VOLUME OF SPECIMEN.
5. QUANTITIES MEASURED	WEIGHT OF MATERIAL RETAINED ON SCREEN. HYDROMETER READINGS AT SPECIFIC TIME INTERVALS, WEIGHT OF DRIED SPECIMEN.	WEIGHT AND VOLUME OF MOIST SPECIMEN, OVEN-DRIED WEIGHT OF SPECIMEN, AND WEIGHT OF EQUAL VOLUME OF WATER TO SPECIMEN.	WEIGHT AND VOLUME OF MOIST SPECIMEN AND OVEN DRIED WEIGHT OF SAME SPECIMEN, AND SPECIFIC GRAVITY OF THE SOLIDS.	WEIGHT AND VOLUME OF MOIST SPECIMEN AND OVEN DRIED WEIGHT OF SAME SPECIMEN, AND SPECIFIC GRAVITY OF THE SOLIDS.
6. QUANTITIES COMPUTED FROM MEASUREMENTS	PERCENTAGE WEIGHT OF MATERIAL BETWEEN SCREEN SIZES. EFFECTIVE DIAMETER OF SMALLER SIZES FROM HYDROMETER TEST. PLOT OF GRAIN SIZE DISTRIBUTION.	WATER CONTENT (IS ON A WEIGHT BASIS) OR THE SPECIFIC GRAVITY OF THE SOLIDS AND THEN THE DEGREE OF SATURATION (IS ON A VOLUME BASIS).	UNIT WEIGHTS OF SOLIDS, UNIT DRY WEIGHT OF SOIL, UNIT WET WEIGHT OF SOIL.	POROSITY AND/OR VOID RATIO.
7. COVERAGE	NOT APPLICABLE.	NOT APPLICABLE.	NOT APPLICABLE.	NOT APPLICABLE.
8. EFFECTIVE DEPTH	NOT APPLICABLE.	NOT APPLICABLE.	NOT APPLICABLE.	NOT APPLICABLE.
9. LIMITATIONS	MATERIAL MUST BE FREE OF FOREIGN MATTER.	SPECIMEN MUST CONTAIN ORIGINAL MOISTURE.	NOT APPLICABLE.	NOT APPLICABLE.
10. SENSITIVITY	DEPENDS ON ADHERENCE TO STANDARD TEST PROCEDURES AND ACCURACY OF MEASUREMENTS.	DEPENDS ON ADHERENCE TO STANDARD TEST PROCEDURES AND ACCURACY OF MEASUREMENTS.	DEPENDS ON ADHERENCE TO STANDARD TEST PROCEDURES AND ACCURACY OF MEASUREMENTS.	DEPENDS ON ADHERENCE TO STANDARD TEST PROCEDURES AND ACCURACY OF MEASUREMENTS.
11. POSSIBLE ERRORS IN INTERPRETATION	SPECIMEN MAY NOT BE REPRESENTATIVE.	SPECIMEN MAY NOT BE REPRESENTATIVE.	SPECIMEN MAY NOT BE REPRESENTATIVE.	SPECIMEN MAY NOT BE REPRESENTATIVE.
12. PRINCIPAL INSTRUMENTS USED	SET OF SIEVES. HYDROMETER.	OVEN, ANALYTIC OR BEAM BALANCE, VOLUMETRIC SPECIMEN CUTTER.	ANALYTIC OR BEAM BALANCE, CONTAINERS.	ANALYTIC OR BEAM BALANCE, CONTAINERS.
13. ENERGY SOURCES	HEAT FOR DRYING OF SPECIMEN.	HEAT FOR DRYING OF MOIST SPECIMEN.	HEAT FOR DRYING OF SPECIMENS.	HEAT FOR DRYING OF SPECIMENS.
14. CREW SIZE REQUIRED	ONE	ONE.	ONE.	ONE
15. TIME REQUIRED AND WORK ACCOMPLISHED	8 TO 12 TESTS PER 8-HOUR SHIFT.	3 TO 5 TESTS PER 8-HOUR SHIFT	8 TO 12 TESTS PER 8-HOUR SHIFT.	8 TO 12 TESTS PER 8-HOUR SHIFT.
16. COST	ABOUT $25 PER TEST.	$50 TO $75 PER TEST.	ABOUT $25 PER TEST.	ABOUT $20 PER TEST.
17. POTENTIAL AREAS OF IMPROVEMENT	DEVELOP IMPROVED METHODS.	DEVELOP IMPROVED METHODS.	DEVELOP IMPROVED METHODS	DEVELOP IMPROVED METHODS.

Table C-1: DEFINITION OF ITEMS ON FIGURE C-1 (Sheet 12 of 16)

CONDITIONS	LABORATORY TESTING OF SOIL			
	CONSISTENCY	SHEARING STRENGTH	UNCONFINED COMPRESSIVE STRENGTH	PERMEABILITY
1. SITE SELECTION	DETAILED INVESTIGATION.	DETAILED INVESTIGATION.	DETAILED INVESTIGATION.	DETAILED INVESTIGATION.
2. ENGINEERING APPLICATION	DETERMINE DEGREE OF FIRMNESS FOR A FINE-GRAINED SOIL FOR CLASSIFICATION.	DETERMINE STABILITY OF SOIL.	DETERMINE COMPRESSIVE STRENGTH OF SOIL AS AN INDIRECT METHOD OF DETERMINING SOIL SHEARING STRENGTH.	DETERMINE ABILITY OF A SOIL TO CONDUCT FREE WATER UNDER A GIVEN HYDRAULIC GRADIENT.
3. GEOLOGICAL ENVIRONMENT	CLAY AND SILT.	SOIL.	SOIL.	SOIL.
4. PRINCIPLE USED	CHANGE IN STRENGTH WITH CHANGE IN MOISTURE CONTENT.	MEASUREMENT OF FORCE THAT CAUSES A SPECIMEN TO FAIL.	UNIAXIAL LOADING TO SPECIMEN FAILURE.	MEASURING THE AMOUNT OF WATER FLOW FORCED THROUGH A SPECIMEN.
5. QUANTITIES MEASURED	SPECIMEN VOLUME, WEIGHT AT EACH CONSISTENCY-LIMIT CONDITIONS, AND VOLUME AND WEIGHT OF SPECIMEN WHEN OVEN-DRIED.	NORMAL AND SHEARING FORCES IN DIRECT SHEAR TEST. NORMAL AND CONFINING PRESSURES, AND PORE PRESSURE IF APPLICABLE, IN TRIAXIAL TEST. SPECIMEN SIZE AND VOLUME CHANGE DURING SHEARING IN BOTH.	AXIAL APPLIED FORCE AND VERTICAL DEFORMATION OF THE SPECIMEN AT INCREMENTAL PERIODS DURING TEST.	WATER VISCOSITY, LENGTH AND CROSS-SECTIONAL AREA OF SPECIMEN, ELAPSED TEST TIME, AND FLOW QUANTITY AND HEAD LOSS FOR CONSTANT-HEAD TEST, OR INSIDE CROSS-SECTIONAL AREA OF STANDPIPE AND DIFFERENCE IN STANDPIPE WATER LEVEL DURING TEST FOR FALLING-HEAD TEST.
6. QUANTITIES COMPUTED FROM MEASUREMENTS	WATER CONTENT AT EACH CONSISTENCY LIMIT, AND CONSISTENCY INDEXES.	ANGLE OF INTERNAL FRICTION AND COHESION INTERCEPT FROM MOHR ENVELOPE DIAGRAM OF TEST RESULTS. MODULUS OF ELASTICITY FROM SLOPE OF STRESS STRAIN CURVE.	AXIAL STRAIN AND COMPRESSIVE STRESS. USUALLY PLOT OF STRESS VERSUS STRAIN IS MADE.	COEFFICIENT OF PERMEABILITY FOR LAMINAR FLOW.
7. COVERAGE	NOT APPLICABLE.	NOT APPLICABLE.	NOT APPLICABLE.	NOT APPLICABLE.
8. EFFECTIVE DEPTH	NOT APPLICABLE.	NOT APPLICABLE.	NOT APPLICABLE.	NOT APPLICABLE.
9. LIMITATIONS	ONLY SUITABLE FOR FINE-GRAINED SOILS (MINUS 40 MESH).	IN SITU CONDITIONS ARE ONLY APPROXIMATED IN TRIAXIAL TEST. STATE-OF-STRESS ONLY DETERMINED AT FAILURE IN DIRECT SHEAR TEST.	SOIL MUST HAVE SOME COHERENCE.	RESULTS ONLY VALID FOR PARTICULAR SOIL TESTED. ONLY CONSIDERS STEADY-STATE FLOW CONDITIONS.
10. SENSITIVITY	DEPENDS ON ADHERENCE TO STANDARD TEST PROCEDURES AND ACCURACY OF MEASUREMENTS	DEPENDS ON ADHERENCE TO STANDARD TEST PROCEDURES AND ACCURACY OF MEASUREMENTS.	DEPENDS ON ADHERENCE TO STANDARD TEST PROCEDURES AND ACCURACY OF MEASUREMENTS.	DEPENDS ON ADHERENCE TO STANDARD TEST PROCEDURES AND ACCURACY OF MEASUREMENTS.
11. POSSIBLE ERRORS IN INTERPRETATION	SPECIMEN ALLOWED TO DRY BEFORE TESTING CAN GIVE ERRONEOUS RESULTS. SPECIMEN SLIPS RATHER THAN FLOWS IN LIQUID LIMIT TEST.	IN SOFT SOILS, SAMPLE DISTURBANCE FREQUENTLY OVER-COMPENSATED BY TRIAXIAL TESTS.	SINGLE SPECIMEN RESULT MAY VARY WIDELY FROM AVERAGE STRENGTH.	TEST PROCEDURES MAY NOT BE INDICATIVE OF ACTUAL IN SITU CONDITIONS.
12. PRINCIPAL INSTRUMENTS USED	LIQUID LIMIT DEVICE, SHRINKAGE DISH.	DIRECT SHEAR DEVICE, TRIAXIAL COMPRESSION DEVICE.	UNCONFINED COMPRESSION DEVICE.	CONSTANT-HEAD AND FALLING-HEAD TEST DEVICES.
13. ENERGY SOURCES	HEAT FOR DRYING OF SPECIMENS.	MECHANICAL JACK OR HYDRAULIC FLUID PRESSURED BY PUMP OR HAND LEVER.	MECHANICAL JACK OR HYDRAULIC FLUID PRESSURED BY PUMP OR HAND LEVER.	WATER HEAD.
14. CREW SIZE REQUIRED	ONE	1 OR 2	1 OR 2	ONE.
15. TIME REQUIRED AND WORK ACCOMPLISHED	3 TO 5 DETERMINATIONS FOR EACH CONSISTENCY LIMIT AND INDEX PER 8-HOUR SHIFT.	5 TO 8 DIRECT SHEAR AND 2 TO 3 TRIAXIAL SHEAR TESTS PER 8-HOUR SHIFT.	1 TO 3 HOURS PER TEST.	3 TO 6 TESTS PER 8-HOUR SHIFT.
16. COST	$30 TO $40 PER TEST.	$15 TO $20 PER TEST FOR DIRECT SHEAR AND ABOUT $35 FOR TRIAXIAL SHEAR.	ABOUT $50 PER TEST.	ABOUT $75 TO $85 PER TEST.
17. POTENTIAL AREAS OF IMPROVEMENT	DEVELOP IMPROVED METHODS.	DEVELOP IMPROVED METHODS.	DEVELOP IMPROVED METHODS.	DEVELOP IMPROVED METHODS.

Table C-1: DEFINITION OF ITEMS ON FIGURE C-1 (Sheet 13 of 16)

CONDITIONS	LABORATORY TESTING OF SOIL	LABORATORY TESTING OF ROCK		
	SWELLING	IDENTIFICATION	SPECIFIC GRAVITY	APPARENT POROSITY
1. SITE SELECTION STAGE	DETAILED INVESTIGATION.	DETAILED INVESTIGATION.	DETAILED INVESTIGATION.	DETAILED INVESTIGATION.
2. ENGINEERING APPLICATION	DETERMINE THE SWELLING CHARACTERISTICS OF A CLAY.	FOR CLASSIFICATION OF ROCK TYPES.	USED IN ENGINEERING DESIGN.	USED IN ENGINEERING DESIGN.
3. GEOLOGICAL ENVIRONMENT	CLAYS.	ROCK.	ROCK.	ROCK.
4. PRINCIPLE USED	CHANGE IN VOLUME AND EXPANSION PRESSURE OF SPECIMEN WHEN WATER IS ADDED.	UNAIDED VISUAL INSPECTION, MICROSCOPIC EXAMINATION, CHEMICAL AND SPECTROGRAPHIC ANALYSIS, X-RAY DIFFRACTION, DIFFERENTIAL THERMAL ANALYSIS.	RATIO OF THE SPECIMEN MASS TO THE MASS OF AN EQUAL VOLUME OF WATER AT A SPECIFIED TEMPERATURE.	RATIO OF PORE SPACE VOLUME TO THE TOTAL VOLUME OF SPECIMEN.
5. QUANTITIES MEASURED	DIFFERENCE IN SAMPLE VOLUME AT DRY AND SATURATED CONDITIONS. PRESSURE EXERTED BY SAMPLE WHEN IT IS WETTED.	MINERAL SIZE, SHAPE, ARRANGEMENT AND COMPOSITION. DEGREE OF COHERENCE.	METHOD 1 - DRY WEIGHT, WET WEIGHT IN AIR, WET WEIGHT IN WATER. METHOD 2 - DRY WEIGHT, BULK VOLUME. METHOD 3 - DRY WEIGHT, APPARENT VOLUME (FROM SIZE MEASUREMENTS).	METHOD 1 - DRY WEIGHT, WET WEIGHT, APPARENT VOLUME (FROM SIZE MEASUREMENTS). METHOD 2 - APPARENT VOLUME (BY PYCNOMETER), APPARENT VOLUME (FROM SIZE MEASUREMENTS).
6. QUANTITIES COMPUTED FROM MEASUREMENTS	CHANGE IN VOLUME AND/OR EXPANSION PRESSURE WHEN WETTED.	NOT APPLICABLE.	SPECIFIC GRAVITY IN GRAMS PER CUBIC CENTIMETER.	APPARENT POROSITY IN PERCENT.
7. COVERAGE	NOT APPLICABLE.	NOT APPLICABLE.	NOT APPLICABLE.	NOT APPLICABLE.
8. EFFECTIVE DEPTH	NOT APPLICABLE.	NOT APPLICABLE.	NOT APPLICABLE.	NOT APPLICABLE.
9. LIMITATIONS	GIVES APPROXIMATE INFORMATION ONLY.	MUST HAVE UNDISTURBED SAMPLE FOR SOME OBSERVATIONS.	NOT APPLICABLE.	NOT APPLICABLE.
10. SENSITIVITY	DEPENDS ON ADHERENCE TO RECOMMENDED TEST PROCEDURES AND ACCURACY OF MEASUREMENTS.	DEPENDS ON COMPLEXITY OF COMPOSITION AND TEXTURE.	DEPENDS ON ADHERENCE TO STANDARD TEST PROCEDURES AND ACCURACY OF MEASUREMENTS.	DEPENDS ON ADHERENCE TO STANDARD TEST PROCEDURES AND ACCURACY OF MEASUREMENTS.
11. POSSIBLE ERRORS IN INTERPRETATION	TEST PROCEDURES NOT INDICATIVE OF ACTUAL IN SITU CONDITIONS.	SAMPLE MAY NOT BE REPRESENTATIVE.	SPECIMEN MAY NOT BE REPRESENTATIVE.	SAMPLE MAY NOT BE REPRESENTATIVE.
12. PRINCIPAL INSTRUMENTS USED	SIEVE SCREENS AND GRADUATED CYLINDER. CONSOLIDOMETER.	HAND LENS, PETROGRAPHIC, BINOCULAR, OR ELECTRON MICROSCOPE, X-RAY DIFFRACTOMETER, DIFFERENTIAL THERMAL ANALYZER, SPECTROGRAPH, QUALITATIVE CHEMICAL LABORATORY EQUIPMENT.	OVEN, ANALYTIC OR BEAM BALANCE, PYCNOMETER, MICROMETER.	OVEN, ANALYTIC BALANCE, PYCNOMETER, MICROMETER.
13. ENERGY SOURCES	GRAVITY.	ELECTRICAL CURRENT.	HEAT FOR DRYING OF SPECIMEN.	HEAT FOR DRYING OF SPECIMEN.
14. CREW SIZE REQUIRED	ONE.	ONE.	ONE.	ONE.
15. TIME REQUIRED AND WORK ACCOMPLISHED	USUALLY OVER A 24-HOUR TEST PERIOD.	DEPENDS ON EXPERIENCE OF EXAMINER AND COMPLEXITY OF SAMPLE MINERALOGY.	20 TO 60 DETERMINATIONS PER 8-HOUR SHIFT	20 TO 60 DETERMINATIONS PER 8-HOUR SHIFT
16. COST	ABOUT $25 PER TEST	VARIABLE UPON METHODS USED.	ABOUT $15 PER TEST.	ABOUT $15 PER TEST.
17. POTENTIAL AREAS OF IMPROVEMENT	DEVELOP IMPROVED METHODS.	DEVELOP IMPROVED METHODS.	DEVELOP IMPROVED METHODS.	DEVELOP IMPROVED METHODS.

Table C-1: DEFINITION OF ITEMS ON FIGURE C-1 (Sheet 14 of 16)

CONDITIONS	LABORATORY TESTING OF ROCK			
	HARDNESS	ABRASION RESISTANCE	WEATHERING RESISTANCE	UNIAXIAL COMPRESSIVE STRENGTH
1. SITE SELECTION STAGE	DETAILED INVESTIGATION.	DETAILED INVESTIGATION.	DETAILED INVESTIGATION.	DETAILED INVESTIGATION.
2. ENGINEERING APPLICATION	USED IN DETERMINATION OF "DRILL-ABILITY".	USED IN SELECTION OF MUCK HANDLING AND PUMPING EQUIPMENT.	ESTIMATION OF LONG-TERM STABILITY FOR TUNNEL WALLS.	USED FOR SELECTION OF EXCAVATION METHOD, DETERMINATION OF SUPPORT REQUIREMENTS.
3. GEOLOGICAL ENVIRONMENT	ROCK.	ROCK.	ROCK.	ROCK.
4. PRINCIPLE USED	REBOUND OF POINTED HAMMER OR PISTON, SCRATCHING, CRUSHING, MINIATURE DRILLED HOLES.	ABRADING OF MATERIAL BY ACCELERATED WEAR.	AIR-WATER SLAKING TESTS, SWELLING TESTS, LEACHING TESTS.	UNIAXIAL LOADING TO COMPRESSIONAL FAILURE.
5. QUANTITIES MEASURED	HEIGHT OF HAMMER OR PISTON REBOUND, AMOUNT OF MATERIAL CRUSHED TO A 0.5 MM SIZE AND HAMMER BLOWS REQUIRED.	AMOUNT OF MATERIAL ABRADED DURING TEST.	RESISTANCE TO SLAKING, SOLUTION, OR EROSION DETERMINED. IN SWELLING TEST DETERMINE DIFFERENCE IN SAMPLE VOLUME AT DRY AND SATURATED CONDITIONS AND PRESSURE EXERTED BY SAMPLE WHEN WETTED.	SPECIMEN LENGTH AND DIAMETER, COMPRESSIVE LOAD REQUIRED TO CAUSE FAILURE.
6. QUANTITIES COMPUTED FROM MEASUREMENTS	RELATIVE HARDNESS.	RELATIVE ABRASIVENESS.	ESTIMATED TIME FOR ROCK TO DETERIORATE.	UNIAXIAL COMPRESSIVE STRENGTH IN PSI.
7. COVERAGE	NOT APPLICABLE.	NOT APPLICABLE.	NOT APPLICABLE.	NOT APPLICABLE.
8. EFFECTIVE DEPTH	NOT APPLICABLE.	NOT APPLICABLE.	NOT APPLICABLE.	NOT APPLICABLE.
9. LIMITATIONS	DEPENDS ON PROPERTIES OF INDIVIDUAL GRAINS AND NATURE OF GRAIN BONDING.	DEPENDS ON PROPERTIES OF INDIVIDUAL GRAINS AND NATURE OF GRAIN BONDING.	TEST NOT QUANTITATIVE.	INTACT, FRACTURE-FREE SPECIMENS REQUIRED.
10. SENSITIVITY	DEPENDS ON ADHERENCE TO STANDARD TEST PROCEDURES AND ACCURACY OF MEASUREMENTS.	DEPENDS ON ADHERENCE TO STANDARD TEST PROCEDURES AND ACCURACY OF MEASUREMENTS.	DEPENDS ON LENGTH OF TEST PERIOD.	DEPENDS ON ADHERENCE TO STANDARD TEST PROCEDURES AND ACCURACY OF MEASUREMENTS.
11. POSSIBLE ERRORS IN INTERPRETATION	SPECIMEN MAY NOT BE INDICATIVE OF IN SITU MASS. RESULTS ARE ONLY RELATIVE.	RESULTS ARE ONLY RELATIVE.	DIFFICULT TO SIMULATE LONG TERM WEATHERING EFFECTS IN SHORT TIME PERIOD.	SINGLE SPECIMEN MAY VARY WIDELY FROM AVERAGE STRENGTH.
12. PRINCIPAL INSTRUMENTS USED	SHORE SCLEROSCOPE, SCHMIDT IMPACT HAMMER, PROTODYAKONOV DROP TESTER AND VOLUMETER, MICROBIT DRILL.	DORRY ABRASIVE MACHINE, PADDLE TYPE MACHINE, LOS ANGELES ABRASION MACHINE.	SWELLING TEST - SIEVE SCREENS, GRADUATED CYLINDER, CONSOLIDOMETER.	DIAMOND CORE DRILL, DIAMOND SAW, SURFACE GRINDER, POLISHING LAP, CALIPER, HYDRAULIC PRESS.
13. ENERGY SOURCES	GRAVITY, SPRINGS.	ELECTRICAL POWER.	NOT APPLICABLE.	HYDRAULIC FLUID PRESSURED BY PUMP OR HAND LEVER.
14. CREW SIZE REQUIRED	ONE.	ONE.	ONE.	ONE.
15. TIME REQUIRED AND WORK ACCOMPLISHED	ABOUT 25 SAMPLES PER 8-HOUR SHIFT USING SCLEROSCOPE OR IMPACT HAMMER.	4 TO 8 TESTS PER 8-HOUR SHIFT.	SLAKING AND LEACHING TESTS MAY BE CONTINUED FOR SEVERAL WEEKS.	ABOUT 15 SAMPLES PER 8-HOUR SHIFT.
16. COST	ABOUT $15 PER TEST FOR SCLEROSCOPE.	ABOUT $80 PER TEST FOR LOS ANGELES TEST.	ABOUT $5 TO $10 PER TEST.	$20 TO $40 PER TEST.
17. POTENTIAL AREAS OF IMPROVEMENT	DEVELOP IMPROVED METHODS.	DEVELOP IMPROVED METHODS.	DEVELOP A STANDARD TEST METHOD.	DEVELOP IMPROVED METHODS.

Table C-1: DEFINITION OF ITEMS ON FIGURE C-1 (Sheet 15 of 16)

CONDITIONS	LABORATORY TESTING OF ROCKS			
	UNIAXIAL SHEAR STRENGTH	UNIAXIAL TENSILE STRENGTH	UNIAXIAL FLEXURAL STRENGTH	TRIAXIAL COMPRESSIVE & SHEAR STRENGTH
1. SITE SELECTION STAGE	DETAILED INVESTIGATION.	DETAILED INVESTIGATION.	DETAILED INVESTIGATION.	DETAILED INVESTIGATION.
2. ENGINEERING APPLICATION	LIMITED.	LIMITED.	USED IN DESIGN OF GROUND SUPPORT.	USED IN SELECTION OF EXCAVATION METHOD.
3. GEOLOGICAL ENVIRONMENT	ROCK.	ROCK, ESPECIALLY LAYERED ROCK.	ROCK, ESPECIALLY LAYERED ROCK.	ROCK.
4. PRINCIPLE USED	LOADING TO SHEARING FAILURE.	DIRECT, INDIRECT, RING, AND POINT LOAD TESTS USED.	LOADING TO BENDING OR FLEXURAL FAILURE.	UNIAXIAL LOADING, WITH CONFINING PRESSURE, TO SPECIMEN FAILURE.
5. QUANTITIES MEASURED	CROSS-SECTIONAL AREA, THICKNESS OR DIAMETER OF SPECIMEN, FORCE OR TORQUE REQUIRED TO CAUSE FAILURE, RADIUS OF PUNCH. MEASUREMENTS NEEDED DEPEND ON TEST TECHNIQUE.	SPECIMEN LENGTH AND DIAMETER, TENSILE LOAD CAUSING FAILURE IN INDIRECT, RING AND POINT LOAD TESTS.	SPECIMEN DIAMETER OR THICKNESS AND WIDTH, LENGTH BETWEEN BEARING EDGES OF LOWER PLATE, APPLIED LOAD AT FAILURE.	SPECIMEN LENGTH AND DIAMETER, CONFINING PRESSURE, COMPRESSIVE LOAD REQUIRED TO CAUSE FAILURE, STRAIN RATE, DEFORMATION, INCLINATION OF FAILURE PLANE.
6. QUANTITIES COMPUTED FROM MEASUREMENTS	UNIAXIAL SHEAR STRENGTH IN PSI.	UNIAXIAL TENSILE STRENGTH IN PSI.	UNIAXIAL FLEXURAL STRENGTH IN PSI. MODULUS OF RUPTURE.	CONSTRUCT A STRESS DIFFERENCE VS AXIAL STRAIN CURVE. CONSTRUCT MOHR STRESS CIRCLES ON ARITHMETIC PLOT WITH SHEAR STRESSES AS ORDINATES AND NORMAL STRESSES AS ABSCISSAS. DRAW MOHR ENVELOPE TANGENT TO MOHR CIRCLES. DETERMINE ANGLE OF SHEARING RESISTANCE AND THE COHESION INTERCEPT.
7. COVERAGE	NOT APPLICABLE.	NOT APPLICABLE.	NOT APPLICABLE.	NOT APPLICABLE.
8. EFFECTIVE DEPTH	NOT APPLICABLE.	NOT APPLICABLE.	NOT APPLICABLE.	NOT APPLICABLE.
9. LIMITATIONS	INTACT, FRACTURE-FREE SPECIMEN REQUIRED.	INTACT, FRACTURE-FREE SPECIMENS REQUIRED.	INTACT, FRACTURE-FREE SPECIMENS REQUIRED.	INTACT, FRACTURE-FREE SPECIMENS REQUIRED.
10. SENSITIVITY	DEPENDS ON ADHERENCE TO RECOMMENDED TEST PROCEDURES AND ACCURACY OF MEASUREMENTS.	DEPENDS ON ADHERENCE TO STANDARD TEST PROCEDURES AND ACCURACY OF MEASUREMENTS.	DEPENDS ON ADHERENCE TO RECOMMENDED TEST PROCEDURES AND ACCURACY OF MEASUREMENTS.	DEPENDS ON ADHERENCE TO STANDARD TEST PROCEDURES AND ACCURACY OF MEASUREMENTS.
11. POSSIBLE ERRORS IN INTERPRETATION	IN SINGLE, DOUBLE, AND PUNCH TESTS, MAJOR SHEAR STRESS BUILDUPS OCCUR ALONG SHEAR OR PUNCH AND DIE EDGES, CAUSING FRACTURE FAILURE IN DIRECTION DIFFERENT FROM THAT OF MAXIMUM SHEAR STRESS.	SPECIMEN CONTAINING UNDETECTED STRUCTURAL FLAWS CAN GIVE ERRONEOUS RESULTS.	SPECIMEN CONTAINING UNDETECTED STRUCTURAL FLAWS CAN GIVE ERRONEOUS RESULTS.	SPECIMEN CONTAINING UNDETECTED STRUCTURAL FLAWS CAN GIVE ERRONEOUS RESULTS.
12. PRINCIPAL INSTRUMENTS USED	DIAMOND CORE DRILL, DIAMOND SAW, SURFACE GRINDER, POLISHING LAP, CALIPER, HYDRAULIC PRESS.	LOADING DEVICE, METAL CAPS, CEMENTING MATERIAL, DIAMOND CORE DRILL, DIAMOND SAW, SURFACE GRINDER, CALIPER.	DIAMOND CORE DRILL, DIAMOND SAW, CALIPER, LOADING DEVICE, LOAD-APPLYING AND SUPPORT BLOCKS.	DIAMOND CORE DRILL, DIAMOND SAW, SURFACE GRINDER, POLISHING LAP, CALIPER, LOADING DEVICE, PRESSURE-MAINTAINING DEVICE, TRIAXIAL COMPRESSION CHAMBER, DEFORMATION MEASURING DEVICE, FLEXIBLE MEMBRANE.
13. ENERGY SOURCES	HYDRAULIC FLUID PRESSURED BY PUMP OR HAND LEVER.	HYDRAULIC FLUID PRESSURED BY PUMP OR HAND LEVER.	SCREW JACK, HYDRAULIC FLUID PRESSURED BY PUMP OR HAND LEVER.	HYDRAULIC FLUID PRESSURED BY PUMP OR HAND LEVER.
14. CREW SIZE REQUIRED	ONE.	ONE.	ONE	1 OR 2.
15. TIME REQUIRED AND WORK ACCOMPLISHED	ABOUT 15 SAMPLES PER 8-HOUR SHIFT.	ABOUT 15 SAMPLES PER 8-HOUR SHIFT.	ABOUT 15 SAMPLES PER 8-HOUR SHIFT.	ABOUT 4 SAMPLES PER 8-HOUR SHIFT.
16. COST	$15 TO $25 PER TEST.	ABOUT $15 PER TEST FOR BRAZILIAN, ABOUT $50 FOR DIRECT.	ABOUT $25 TO $35 PER TEST.	ABOUT $50 TO $60 PER TEST.
17. POTENTIAL AREAS OF IMPROVEMENT	DEVELOP A STANDARD TEST METHOD.	DEVELOP IMPROVED METHODS.	DEVELOP A STANDARD TEST METHOD.	DEVELOP IMPROVED METHODS.

Table C-1: DEFINITION OF ITEMS ON FIGURE C-1 (Sheet 16 of 16)

CONDITIONS	LABORATORY TESTING OF ROCK			
	STATIC ELASTIC CONSTANTS	DYNAMIC ELASTIC CONSTANTS	PRIMARY PERMEABILITY	CREEP
1. SITE SELECTION STAGE	DETAILED INVESTIGATION.	DETAILED INVESTIGATION.	DETAILED INVESTIGATION	DETAILED INVESTIGATION.
2. ENGINEERING APPLICATION	USED IN ESTIMATION OF ROCK STABILITY.	USED IN ESTIMATION OF ROCK STABILITY	DETERMINE ABILITY OF A ROCK TO CONDUCT FREE WATER UNDER A GIVEN HYDRAULIC GRADIENT.	USED FOR DETERMINING LONG-TERM ROCK DEFORMATION.
3. GEOLOGICAL ENVIRONMENT	ROCK.	ROCK.	ROCK.	ROCK.
4. PRINCIPLE USED	STRESS-STRAIN RELATIONSHIPS.	DYNAMIC MODULI DETERMINED FROM RESONANT FREQUENCY OR ULTRASONIC PULSE VELOCITIES.	MEASURING THE AMOUNT OF WATER OR AIR FLOW FORCED THROUGH A SPECIMEN.	DETERMINATION OF LONG-TERM CREEP RATE UNDER CONSTANT LOAD.
5. QUANTITIES MEASURED	AXIAL COMPRESSIVE OR TENSILE STRESS, VERTICAL AND LATERAL STRAIN.	RESONANT FREQUENCY METHOD - LONGITUDINAL, TRANSVERSE, AND TORSIONAL FREQUENCIES OF VIBRATING PRISMS OR CYLINDERS, SPECIMEN WEIGHT, LENGTH, AND DIAMETER OF CROSS-SECTIONAL AREA. ULTRASONIC PULSE METHOD - PULSE VELOCITIES OF COMPRESSION AND SHEAR WAVES, SPECIMEN WEIGHT, VOLUME, DENSITY, APPARENT POROSITY, AND DEGREE OF SATURATION.	SAME AS SOIL PERMEABILITY TEST WHEN USING WATER. INLET AND OUTLET PRESSURES AND FLOW RATE WHEN USING GAS.	SPECIMEN DEFORMATION AS A FUNCTION OF TIME, DIMENSIONS OF SPECIMEN, APPLIED LOAD.
6. QUANTITIES COMPUTED FROM MEASUREMENTS	MODULUS OF ELASTICITY (YOUNG'S MODULUS), POISSON'S RATIO, BULK MODULUS, MODULUS OF RIGIDITY, LAME'S CONSTANT.	DYNAMIC MODULUS OF ELASTICITY (DYNAMIC YOUNG'S MODULUS), DYNAMIC POISSON'S RATIO, DYNAMIC MODULUS OF RIGIDITY, DYNAMIC BULK MODULUS, DYNAMIC LAME'S CONSTANT.	COEFFICIENT OF PERMEABILITY FOR LAMINAR FLOW.	STRAIN VS TIME CREEP CURVE PLOTTED.
7. COVERAGE	NOT APPLICABLE.	NOT APPLICABLE.	NOT APPLICABLE.	NOT APPLICABLE.
8. EFFECTIVE DEPTH	NOT APPLICABLE.	NOT APPLICABLE.	NOT APPLICABLE.	NOT APPLICABLE.
9. LIMITATIONS	INTACT, FRACTURE-FREE SPECIMENS REQUIRED.	INTACT, FRACTURE-FREE SPECIMENS REQUIRED.	RESULTS ONLY VALID FOR PARTICULAR ROCK TESTED. ONLY CONSIDERS STEADY-STATE FLOW CONDITIONS.	CONSIDERABLE LENGTH OF TIME REQUIRED FOR TEST.
10. SENSITIVITY	DEPENDS ON ADHERENCE TO RECOMMENDED TEST PROCEDURES AND ACCURACY OF MEASUREMENTS.	DEPENDS ON ADHERENCE TO RECOMMENDED TEST PROCEDURES AND ACCURACY OF MEASUREMENTS.	DEPENDS ON ADHERENCE TO STANDARD TEST PROCEDURES AND ACCURACY OF MEASUREMENTS.	DEPENDS ON ADHERENCE TO RECOMMENDED TEST PROCEDURES AND ACCURACY OF MEASUREMENTS.
11. POSSIBLE ERRORS IN INTERPRETATION	SPECIMEN MAY NOT BE INDICATIVE OF IN SITU MASS.	SPECIMEN MAY NOT BE INDICATIVE OF IN SITU MASS.	TEST PROCEDURES MAY NOT BE INDICATIVE OF ACTUAL IN SITU CONDITIONS.	RESULTS MAINLY QUALITATIVE.
12. PRINCIPAL INSTRUMENTS USED	DIAMOND CORE DRILL, DIAMOND SAW, SURFACE GRINDER, LOADING DEVICE, CLAMPING DEVICE WITH STRAIN GAUGES.	DIAMOND CORE DRILL, DIAMOND SAW, SURFACE GRINDER, BALANCE, CALIPER. RESONANT FREQUENCY METHOD - DRIVING CIRCUIT, PICKUP CIRCUIT, SPECIMEN SUPPORT. ULTRASONIC PULSE METHOD - PULSE GENERATOR UNIT, TRANSDUCERS, PREAMPLIFIER, DISPLAY AND TIMING UNIT.	CONSTANT-HEAD AND FALLING HEAD WATER TEST DEVICES. AIR PERMEAMETER.	DIAMOND CORE DRILL, DIAMOND SAW, SURFACE GRINDER, POLISHING LAP, CALIPER, LOADING DEVICE, STRAIN-MEASURING DEVICES.
13. ENERGY SOURCES	HYDRAULIC FLUID PRESSURED BY PUMP OR HAND LEVER.	ELECTRICAL CURRENT.	WATER HEAD OR COMPRESSED AIR PRESSURE.	GRAVITY.
14. CREW SIZE REQUIRED	ONE.	ONE.	ONE.	ONE.
15. TIME REQUIRED AND WORK ACCOMPLISHED	4 TO 6 TESTS PER 8-HOUR SHIFT.	8 TO 12 TEST PER 8-HOUR SHIFT FOR YOUNG'S MODULUS AND POISSON'S RATIO.	6 TO 10 TESTS PER 8-HOUR SHIFT.	TESTS MAY EXTEND OVER MANY WEEKS.
16. COST	$75 TO $85 PER TEST FOR YOUNG'S MODULUS AND POISSON'S RATIO.	$50 TO $60 PER TEST FOR YOUNG'S MODULUS AND POISSON'S RATIO.	$30 TO $40 PER TEST.	VARIABLE UPON LENGTH OF TEST PERIOD.
17. POTENTIAL AREAS OF IMPROVEMENT	DEVELOP STANDARD TEST METHODS.	DEVELOP STANDARD TEST METHODS.	DEVELOP IMPROVED METHODS.	DEVELOP IMPROVED ACCELERATED METHODS.

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Appendix D

ROCK MECHANICS DESIGN

The design of any facility utilizing underground space for the storage of air under pressure must be predicated upon sound rock mechanics principles if adequate safety requirements are to be maintained. Although the mechanical behavior of rock is highly site-specific, a general design method can be developed if certain assumptions are made. For the purposes of this study, it has been assumed that the required cavern space for air storage in hard rock would be excavated in granite, using room and pillar methods.

A hypothetical cavern layout is shown in Figure D-1.

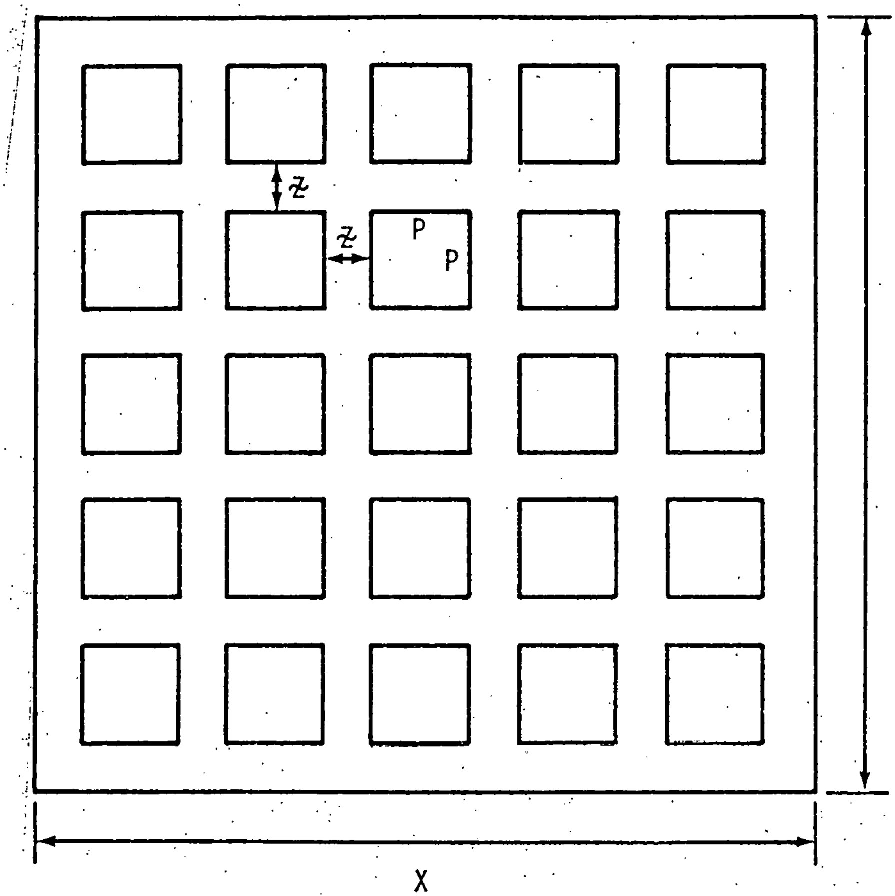

Figure D-1. Hypothetical Storage Cavern

All calculations are based on this idealized layout. It should be noted that under actual conditions the final cavern configuration must be adapted to varying ground conditions and to the appropriate mining methods. In carrying out the assessment for this study, a standard room and pillar design was selected that might be representative of caverns suited to a wide range of sites.

D.1 CAVERN DESIGN

Two types of cavern are to be considered in the design of a compressed air storage facility in hard rock:

- Water compensated
- Noncompensated

In the design of the water compensated cavern, a static head of water is used to maintain a constant delivery pressure to the turbine inlet. This waterhead is obtained by excavating a shaft and surface reservoir of sufficient size and depth to provide the required water pressure, volume, and flow rate to the cavern. In addition to the surface reservoir, a distribution system must be constructed below the air storage cavern to evenly distribute the water over the entire area. In this manner, air pockets and uneven flow can be avoided. The use of this concept requires that large differential temperatures between the cavern walls and the water be avoided in order to ensure that the structural integrity of the cavern will be maintained. Previous studies have indicated that rapid heating and cooling of rock surfaces will produce stresses of sufficient magnitude to create fracturing and subsequent spalling (Ref. 1).

For this study, the cavern operating design temperature selected has been a maximum of 50 C (125 F). This temperature requires that aftercoolers be used in conjunction with the compressors when pressurizing a cavern. The depth at which the compensated cavern will be excavated is that depth at which the static head of the water is equal to the cavern storage pressure. As the cavern air is discharged through the turbines, the static waterhead will change slightly as a result of the change in water elevation as the cavern fills. To maintain the turbine delivery pressure within reasonable limits without creating a cavern of unreasonable areal extent, the cavern height has been assumed to be 25 feet.

Another consideration for stable design is the extraction ratio. This quantity is defined as the ratio of the excavated area to the original area. In order to provide an adequate safety factor against surface subsidence, the extraction ratio has been limited to a maximum of 0.5 for both cases.

The design for noncompensated caverns requires that a cavern be pressurized to a point beyond that required for turbine operation. This means that the air discharge must be regulated to obtain the required operating pressure range. Although the heating and cooling cycles in this design will not be as pronounced as in the case of the water compensated design, the cavern operating temperature is also limited to a maximum of 50 C (125 F); this is because of the undesirable effects of temperature cycling upon rock stability.

To ensure that no air leakage will occur, the noncompensated cavern is designed to operate against a hydrostatic head. This utilizes the static head of the ground water below the water table (assumed to be at an average depth of 100 feet) as a pressure seal against the air in the cavern. Here, too, the cavern height is assumed to be 25 feet, to relate to current mining equipment characteristics and to provide a good basis for comparison of the two designs.

D.2 DESIGN EQUATIONS

The equations used in the rock mechanics analysis have been adapted from the study by A.H. Wilson (Ref. 2). It has been assumed that the load imposed upon a pillar consists of the weight of the overburden halfway to adjacent pillars plus the weight of one-half the height of the pillar. The combination of these loads forms the tributary area load or the total load on the pillar. It is assumed that the point of maximum stress occurs at the midpoint of the pillar and that the rock is competent and homogeneous.

Cavern depths ranging from a minimum of 500 feet to a maximum of 3500 feet were selected. The minimum depth of 500 feet was chosen to provide sufficient overburden to ensure that no upheaval or air leakage will occur. Below the maximum depth of 3500 feet, mined storage becomes uneconomical as a result of low extraction ratios and increased mining costs.

As stated previously, it has been assumed that both designs (water compensated and noncompensated) will be excavated in granite. Since the properties of any rock are site-specific, it was necessary to assume properties of the rock in order to perform the analysis. Although these assumptions may not correspond to the in situ rock properties at an actual site, they are based on experience and should be representative of rock properties at suitable sites. The method of analysis is a proven one in cavern design and may be applied to any rock, once the properties are known.

The determination of the ability of a pillar to support the load imposed upon it is based upon the concept of a pillar core. In this concept it is theorized that the load imposed upon a pillar is carried by a central core, which is completely surrounded and constrained by rock that has already passed its yield point and undergone some movement toward the drift. The constraint given to the central core by this "yield zone" can increase its strength considerably. Beginning at the edge of the pillar, the stress gradually increases from zero till a peak abutment stress is reached. This peak represents the failure stress of the rock under the loading conditions. Beyond this peak, the rock stress has not reached the yield point and the rock will behave more or less elastically.

The value of the peak abutment stress is a function of the internal angle of friction, the rock mass cohesion, the average confining stress, and the loading conditions. The distance into the pillar at which the abutment stress is reached is a function of the frictional resistance developed in the yield zone. Assuming the peak abutment stress to be the maximum allowable stress in the pillar, the stress distribution envelope for a square, wide pillar (a pillar whose width is greater than twice the distance into the pillar to the peak abutment stress) becomes a truncated pyramid. With this assumption, the loading capacity of the pillar can be found by claculating the volume under the stress distribution envelope.

The following variables are defined for this analysis:

A_p	=	Area of Pillar, ft^2
$\tan\beta$	=	Passive pressure coefficient
ϕ	=	Internal angle of friction, degrees
d	=	Diameter of water compensation shaft, feet
D	=	Depth to floor of cavern, feet
Gf	=	Generating capacity of facility, MW
H	=	Depth of overburden, feet
L	=	Pillar load capacity, psi
M	=	Pillar height (cavern height), feet
P	=	Pillar width (square pillar), feet
P_c	=	Cavern storage pressure, psia
Q	=	Volume flow rate of water, cfs
R	=	Extraction ratio
T_{al}	=	Tributary area load, psi
t_d	=	Cavern discharge time, hours
ν	=	Maximum velocity of water in compensation shaft, fps
V_e	=	Required cavern volume, ft^3
V	=	Actual cavern volume, ft^3
X_e	=	Estimated cavern side dimension, feet
X	=	Actual cavern side dimension (square cavern), feet
Y	=	Distance into pillar to peak abutment stress, feet
Z	=	Drift width, feet
α	=	Unit weight of rock, pcf
σ_b	=	Average confining stress, psi
σ_o	=	Rock mass cohesion, psi
σ_v	=	Peak abutment stress, psi
ρ_w	=	Unit weight of water, pcf

The following values have been assumed for some of these variables:

$d \leq 30$ feet

500 feet $\leq D \leq$ 3500 feet

G_f = 150 and 600 MW

L = 10,000 psi (granite)

M = 25 feet

40 feet $\leq P \leq$ 160 feet

P_c = 176.6; 588.5; 1,176 psia (water compensated cavern)

= 294 to 176.6; 588.5 to 294; 1,176 to 588.5; 1,176 to 176.6 psia (noncompensated cavern)

$R \leq 0.50$

t_d = 4 and 8 hours

ν = 12 fps

20 feet $\leq Z \leq$ 40 feet

α = 165 pcf (granite)

ρ_w = 62.4 pcf

Tables D-1 and D-2 list the equation values for the two designs.

Table D-1

DESIGN EQUATIONS -- WATER COMPENSATED CAVERN

G_f (MW)	150		600	
t_d (hr)	4	8	4	8
P_c (psia)	V_e (ft^3)	V_e (ft^3)	V_e (ft^3)	V_e (ft^3)
176.6	9,963,000	19,953,000	39,879,000	79,758,000
588.5	2,997,000	5,994,000	11,988,000	23,922,000
1176	1,485,000	2,997,000	5,994,000	11,961,000

Table D-2

DESIGN EQUATIONS -- NONCOMPENSATED CAVERN

G_f (MW)	150		600	
t_d (hr)	4	8	4	8
P_c (psia)	V_e (ft^3)	V_e (ft^3)	V_e (ft^3)	V_e (ft^3)
294-176.6	14,958,000	29,916,000	59,832,000	119,637,000
588.5-294	5,994,000	11,988,000	23,922,000	48,844,000
1176-588.5	2,997,000	5,994,000	11,961,000	23,922,000
1176-176.6	1,755,000	3,510,000	7,047,000	14,067,000

The following equations have been developed for the rock mechanics analysis:

$$\tan\beta = \frac{1 + \sin\phi}{1 - \sin\phi} \tag{1}$$

$$\sigma_v = \left(\frac{\alpha H}{144} + \sigma_b\right)\tan\beta + \sigma_o \tag{2}$$

$$Y = \frac{M}{\sqrt{(\tan\beta)}\,(\tan\beta - 1)}\ \ln\frac{\sigma_v}{\sigma_o + \sigma_b} \tag{3}$$

For water compensated cavern: $D = \dfrac{144\ P_c}{\rho_w} = 2.3076\ P_c$ (4)

For noncompensated cavern: $D = \dfrac{180\ P_c}{\rho_w} + 100 = 2.8846\ P_c + 100$ (5)

$$H = D - M \tag{6}$$

$$T_{al} = \frac{\alpha}{288}\left(\frac{2H}{1-R} + M\right) \tag{7}$$

$$A_p = P^2 \tag{8}$$

$$L = \frac{\sigma_v}{A_p}\left(P^2 - 2PY + \frac{4}{3}Y^2\right) \tag{9}$$

$$R = \frac{(P+Z)^2 - P^2}{(P+Z)^2} \qquad R \leq 0.50 \tag{10}$$

$$X_e = \frac{V_e}{MR} \tag{11}$$

$$X = \left(\frac{(X_e - Z)}{(P+Z)} \text{ (drop decimal)} + 1 \right) (P+Z) + Z \tag{12}$$

$$V = X^2 M R \tag{13}$$

$$Q = \frac{\pi \; d^2 \nu}{4} = \frac{V}{3600 \; t_d} \tag{14}$$

$$d = 0.00543 \sqrt{\frac{V}{t_d}} \tag{15}$$

Now, for conditions of stability to exist,

$$L \geq T_{al} \tag{16}$$

Therefore, at the condition $L = T_{al}$ the maximum possible extraction ratio will be obtained. For this condition the following equations are applicable.

For water compensated cavern:

$$R = 1 - \frac{2.3076 \; P_c - M}{\frac{144}{\alpha} L - \frac{M}{2}} \qquad R \leq 0.50 \tag{17}$$

For noncompensated cavern:

$$R = 1 - \frac{2.8846 \; P_c + 100 - M}{\frac{144}{\alpha} L - \frac{M}{2}} \qquad R \leq 0.5 \tag{18}$$

Assuming L = 10,000 psi, α = 165 pcf, M = 25, and solving for R yields R > 0.5, which will give an appreciable safety factor in all cases. Assuming R = 0.5, Z = 20, and solving for P yields P = 48 feet. This dimension gives a pillar width-to-height ratio of nearly 2:1, which indicates a good, stable design.

D.3 RESULTS

With the calculated dimensions and the mine layout as shown in Figure D-1, the required volumes were corrected to actual volumes. The depth, outside cavern dimensions, and water-compensation shaft diameter were also calculated. The results of this work are shown in Tables D-3 and D-4.

Table D-3

WATER COMPENSATED CAVERN
(R = 0.5, P = 48 Feet, Z = 20 Feet)

P_c	176.6	588.5	1,176
D	500.0	1,358.0	2,714.0

MW	Gf	150		160	
Hours / Psia	t_d	4	8	4	8
P_c = 176.6	X*	908	1317	1795	2547
	V**	10,298,869	21,694,278	40,292,780	81,060,259
	d***	8.71	8.94	17.23	17.28
P_c = 588.5	X	498	703	1044	1386
	V	3,099,918	6,174,836	13,631,065	24,001,502
	d	4.78	4.77	10.02	9.41
P_c = 1176	X	361	498	703	1044
	V	1,632,814	3.099,918	6,174,836	13,631,065
	d	3.47	3.38	6.75	7.09

*Actual square cavern side dimensions in feet
**Actual cavern volume in cubic feet
***Diameter of water compensation shaft

Table D-4

NONCOMPENSATED CAVERN
(Depth Calculated by Maximum Pressure; Volume by Usable Pressure.
R = 0.5, P = 48 Feet, Z = 20 Feet)

P_c	294	588.5	1,176
D	948	1 798	3,492

MW	Gf	150		160	
Hours / Psia	t_d	4	8	4	8
P_c = 294 to 176.6	X*	1108	1584	2196	3146
	V**	15,345,800	31,363,200	60,280,200	123,873,800
P_c = 588.5 to 294	X	700	1040	1448	1992
	V	6,125,000	13,520,000	26,208,800	49,600,800
P_c = 1176 to 588.5	X	496	700	1040	1448
	V	3,075,200	6,125,000	13,520,000	26,208,000
P_c = 1176 to 176.6	X	428	564	768	1108
	V	2,289,800	3,976,200	7,372,800	15,345,800

*Actual square cavern side dimensions in feet
**Actual cavern volume in cubic feet

D.4 CONCLUSIONS

In the preceding analysis the method developed utilizes certain assumptions as to the properties of the host rock. As stated previously, these assumptions are purely general in nature and most probably will not correspond to actual in situ conditions. However, once a specific site has been located, the actual in situ properties can be determined and used in the design. It should be noted that the equations as presented assume a competent, homogeneous rock; they should not be used if serious joints, fractures, or faults are encountered.

As presented, the design methodology yields a very satisfactory safety factor against potential air leakage, surface subsidence, or cavern failure. In addition, limiting the cavern height to 25 feet makes the possibility of severe surface depression in the event of a failure very slight. The possibility of air leakage from the cavern is made negligible by the use of a hydrostatic seal. However, each site should be thoroughly researched as to its porosity, permeability, transmissibility, and potential water table drawdown.

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D-1. Marovelli, R.L., and Veith, K.F., Thermal Conductivity of Rock: Measurement by the Transient Line Source Method, Report of Investigation 6604, Bureau of Mines, U.S. Department of the Interior, 1965.

D-2. Wilson, A.H., "Research into the Determination of Pillar Size, Part 1: An Hypothesis Concerning Pillar Stability," The Mining Engineer (incorporating the Transactions of the Institution of Mining Engineers), Vol. 131, No. 141, Part 9, London, England, June 1972.

Appendix E

ECONOMICS OF STORAGE DEVELOPMENT

This appendix contains, in tabular form, the estimated cost elements in the development of underground reservoirs for CAES.

E-1 CONVENTIONAL CAVERNS

The cost estimates for conventional caverns, compensated, and uncompensated, are contained in Tables E-1 through E-7. The design of these caverns is described in Appendix D, "Rock Mechanic Design," of this report. In the case of the compensated caverns, the smallest air shaft was of 30-inch diameter, to comply with the OSHA regulation that two exits be available from the cavern for the workers building it--the other exit, in this case, being the 12-foot diameter water inlet/outlet shaft. In the case of the uncompensated cavern, a 60-inch diameter mined production shaft served as one exit and a minimum 30-inch diameter escape shaft as the other. The cost of rock disposal is based on creating an esthetically acceptable disposal site. In local circumstances, it may be possible that the mine tailings may have value for construction, thus reducing the cost of construction. The cost of the surface pond is based on the availability of a suitable clay containing soil to form a sealed basin for the reservoir. The times for construction of these caverns are summarized in Tables E-8 and E-9. Interest during construction is calculated based on nominal interest of 10 percent per year and commitment of capital at a uniform rate over the time of construction.

E-2 SOLUTION MINED CAVERNS

A discussion of the geologic aspects has been presented in Appendix B, "Salt Formations in the United States," so the discussion here will be confined to costing. Development time for the solution cavern will range from two to five years, depending on the size facility utilized for storage. Initial testing for feasibility will include core hole drilling and preliminary geological research to determine structure and site suitability. Multiple air shafts were employed when required so as not to exceed the design pressure loss. These shafts were cemented and steel cased. The cost elements are summarized in Tables E-10 through E-16. The category of equipment costs includes water supply wells, brine disposal wells, pumps, buildings and associated piping, as well as, in the case of brine compensated caverns, of surface brine ponds.

E-3 AQUIFER DEVELOPMENT

The development of an aquifer for air storage will require a rather extensive drilling/exploration program. Preliminary data indicating a suitable

Table E-1

COST ELEMENTS: COMPENSATED, CONVENTIONALLY MINED CAVERN - 12 ATM

Generating Power Rating	150 MW		600 MW	
Generating Time Rating	4 Hour	8 Hour	4 Hour	8 Hour
Geology/Land	$ 816,000	$ 1,186,000	$ 1,864,000	$ 3,178,000
Water Shaft	1,458,000	1,458,000	1,458,000	1,458,000
Air Shaft (s)	102,000	102,000	176,000	176,000
Cavern Volume	17,248,000	28,770,000	42,000,000	64,300,000
Waste Rock Disposal	1,275,000	2,785,000	4,985,000	10,450,000
Equipment	1,000,000	1,250,000	2,000,000	3,500,000
Water Storage	1,241,000	2,584,000	4,707,000	10,062,000
Contingency/Insurance	4,975,000	8,129,000	12,694,000	20,349,000
Interest During Construction	8,647,000	21,637,000	27,314,000	44,422,000
TOTAL	37,762,000	67,791,000	97,088,000	157,895,000

Depth of cavern - 415 feet.

Table E-2

COST ELEMENTS: COMPENSATED, CONVENTIONALLY MINED CAVERN - 40 ATM

Generating Power Rating	150 MW		600 MW	
Generating Time Rating	4 Hour	8 Hour	4 Hour	8 Hour
Geology/Land	$ 587,000	$ 697,000	$ 1,164,000	$ 1,524,000
Water Shaft	2,684,000	2,684,000	2,684,000	2,684,000
Air Shaft (s)	225,000	225,000	303,000	303,000
Cavern Volume	6,435,000	11,417,000	21,672,000	30,782,000
Waste Rock Disposal	380,000	758,000	1,678,000	2,950,000
Equipment	750,000	1,000,000	1,800,000	2,000,000
Water Storage	384,000	747,000	1,632,000	2,857,000
Contingency/Insurance	2,392,000	3,685,000	6,651,000	9,285,000
Interest During Construction	3,075,000	5,228,000	11,079,000	15,469,000
TOTAL	16,912,000	26,441,000	48,663,000	67,945,000

Depth of cavern - 1365 feet.

Table E-3

COST ELEMENTS: COMPENSATED, CONVENTIONALLY MINED CAVERN - 80 ATM

Generating Power Rating	150 MW		600 MW	
Generating Time Rating	4 Hour	8 Hour	4 Hour	8 Hour
Geology/Land	$ 725,000	$ 775,000	$ 885,000	$ 1,538,000
Water Shaft	5,125,000	5,125,000	5,125,000	5,125,000
Air Shaft (s)	319,000	319,000	485,000	485,000
Cavern Volume	4,340,000	6,435,000	11,417,000	21, 672, 000
Waste Rock Disposal	202,000	380,000	758,000	1,678,000
Equipment	700,000	1,200,000	1,500,000	2,500,000
Water Storage	231,000	403,000	766,000	1,650,000
Contingency/Insurance	2,398,000	3,059,000	4,401,000	7,435,000
Interest During Construction	2,103,000	3,506,000	5,019,000	12,405,000
TOTAL	16,143,000	21,202,000	30,356,000	54,488,000

Depth of cavern - 2725 feet.

Table E-4

COST ELEMENTS: UNCOMPENSATED, CONVENTIONALLY MINED CAVERN - 20:12 ATM

Generating Power Rating	150 MW		600 MW	
Generating Time Rating	4 Hours	8 Hours	4 Hours	8 Hours
Geology/Land	$ 977,000	$ 1,317,000	$ 2,047,000	$ 3,307,000
Air/Production Shaft (s)	1,354,000	1,354,000	1,354,000	1,354,000
Cavern Volume	23,856,000	38,313,000	51,359,000	87,172,000
Waste Rock Disposal	1,845,000	3,772,000	7,258,000	14,910,000
Equipment	700,000	1,500,000	3,000,000	3,000,000
Contingency/Insurance	6,270,000	10,085,000	13,994,000	24,938,000
Interest	13,533,000	22,056,000	26,730,000	71,605,000
Total Cost	48,535,000	78,397,000	105,742,000	206,286,000

Depth of cavern - 780 feet.

Table E-5

COST ELEMENTS: UNCOMPENSATED, CONVENTIONALLY MINED CAVERN - 40:20 ATM

Generating Power Rating	150 MW		600 MW	
Generating Time Rating	4 Hours	8 Hours	4 Hours	8 Hours
Geology/Land	$ 732,000	$ 980,000	$ 1,418,000	$ 1,708,000
Air/Production Shaft (s)	2,198,000	2,198,000	2,198,000	2,198,000
Cavern Volume	11,123,000	20,040,000	33,985,000	49,925,000
Waste Rock Disposal	738,000	1,628,000	3,055,000	5,970,000
Equipment	1,000,000	1,800,000	2,000,000	3,000,000
Contingency/Insurance	3,370,000	5,861,000	9,418,000	12,775,000
Interest	5,185,000	11,625,000	18,407,000	23,009,000
Total Cost	24,346,000	44,132,000	70,581,000	98,585,000

Depth of cavern - 1460 feet.

Table E-6

COST ELEMENTS: UNCOMPENSATED, CONVENTIONALLY MINED CAVERN - 80:40 ATM

Generating Power Rating	150 MW		600 MW	
Generating Time Rating	4 Hours	8 Hours	4 Hours	8 Hours
Geology/Land	$ 862,000	$ 942,000	$ 1,568,000	$ 1,838,000
Air/Production Shaft (s)	4,584,000	4,584,000	4,584,000	4,584,000
Cavern Volume	6,270,000	11,123,000	21,042,000	33,985,000
Waste Rock Disposal	370,000	738,000	1,628,000	4,358,000
Equipment	750,000	1,000,000	1,800,000	2,000,000
Contingency/Insurance	2,683,000	4,019,000	6,735,000	12,039,000
Interest	4,199,000	8,013,000	14,263,000	26,716,000
Total Cost	19,718,000	30,419,000	51,620,000	85,520,000

Depth of cavern - 2820 feet.

Table E-7

COST ELEMENTS: UNCOMPENSATED, CONVENTIONALLY MINED CAVERN - 80:12 ATM

Generating Power Rating	150 MW		600 MW	
Generating Time Rating	4 Hours	8 Hours	4 Hours	8 Hours
Geology/Land	$ 842,000	$ 882,000	$ 1,438,000	$ 1,608,000
Air/Production Shaft (s)	4,584,000	4,584,000	4,584,000	4,584,000
Cavern Volume	5,525,000	8,526,000	14,196,000	23,856,000
Waste Rock Disposal	275,000	478,000	888,000	1,845,000
Equipment	700,000	700,000	1,000,000	1,500,000
Contingency/Insurance	2,505,000	3,234,000	4,686,000	7,278,000
Interest	3,556,000	5,425,000	8,546,000	16,905,000
Total Cost	17,987,000	23,839,000	35,338,000	57,576,000

Depth of cavern - 2820 feet.

Table E-8

CONSTRUCTION TIMES - COMPENSATED, CONVENTIONALLY MINED CAVERNS

PRESSURE ATM/PSIA	TOTAL TONS	TONS PER DAY	MINED CONSTRUCTION TIME			
			150 MW		600 MW	
			4 HOUR CYCLE	8 HOUR CYCLE	4 HOUR CYCLE	8 HOUR CYCLE
12/176	832,500	800	4.0 years			
	1,730,250	1,000		6.6 years		
	3,375,000	2,000			6.5 years	
	6,714,000	5,000				5.2 years
40/588	252,000	500	2.0 years			
	508,500	800		2.4 years		
	1,021,000	1,000			3.9 years	
	2,016,000	2,000				3.9 years
80/1,176	128,250	500	1.0 years			
	254,250	500		2.0 years		
	508,500	800			2.4 years	
	1,021,500	1,000				3.9 years

Based on 19 hrs/day hoisting time, 3 8-hour shifts/day, 260 days/yr.

Table E-9

CONSTRUCTION TIMES - UNCOMPENSATED, CONVENTIONALLY MINED CAVERNS

PRESSURE ATM/PSIA	TOTAL TONS	TONS PER DAY	MINED CONSTRUCTION TIME			
			150 MW		600 MW	
			4 HOUR CYCLE	8 HOUR CYCLE	4 HOUR CYCLE	8 HOUR CYCLE
80-40	256,000	500	2.0 years			
	510,000	800		2.5 years		
	1,127,250	1,000			4.3 years	
1176-588	3,017,250	2,000				5.8 years
80-12	191,250	500	1.5 years			
	330,750	500		2.5 years		
	614,250	800			3.0 years	
1176-176	1,278,000	1,000				5.0 years
40-20	510,750	800	2.5 years			
	1,127,250	1,000		4.3 years		
	2,184,750	2,000			4.2 years	
588-294	4,133,250	5,000				6.2 years
20-12	1,278,000	1,000	4.9 years			
	2,612,250	2,000		5.0 years		
	5,024,250	5,000			3.9 years	
294-176	10,323,000	5,000				7.9 years

Based on 19 hrs/day hoisting time, 3 8-hour shifts/day, 260 days/yr.

Table E-10

COST ELEMENTS: UNCOMPENSATED, SOLUTION MINED CAVERN - 20:12 ATM

Generating Power Rating	150 MW		600 MW	
Generation Time Rating	4 Hours	8 Hours	4 Hours	8 Hours
Geology/Land	$ 2,684,000	$ 5,084,000	$ 2,836,000	$ 5,236,000
Air Shaft	648,000	648,000	2,604,000	2,604,000
Equipment	5,000,000	5,000,000	13,489,000	13,489,000
Contingency/Insurance	1,713,000	2,033,000	3,786,000	4,266,000
Interest	1,990,000	3,763,000	3,402,000	6,308,000
Total	12,035,000	16,538,000	26,117,000	31,903,000

Depth to top of cavern - 370 feet.

Table E-11

COST ELEMENTS: UNCOMPENSATED, SOLUTION MINED CAVERN - 40:20 ATM

Generating Power Rating	150 MW		600 MW	
Generation Time Rating	4 Hours	8 Hours	4 Hours	8 Hours
Geology/Land	$ 1,574,000	$ 2,774,000	$ 5,534,000	$ 10,334,000
Air Shaft (s)	1,323,000	1,323,000	5,292,000	5,292,000
Equipment	5,000,000	5,000,000	6,000,000	6,000,000
Contingency/Insurance	1,523,000	1,887,000	3,102,000	4,506,000
Interest	1,411,000	2,176,000	2,985,000	6,440,000
Total	10,831,000	13,160,000	22,913,000	32,572,000

Depth to top of cavern - 750 feet.

Table E-12

COST ELEMENTS: UNCOMPENSATED, SOLUTION MINED CAVERN - 80:40 ATM

Generating Power Rating	150 MW		600 MW	
Generation Time Rating	4 Hours	8 Hours	4 Hours	8 Hours
Geology/Land	$ 938,000	$ 1,538,000	$ 2,918,000	$ 5,318,000
Air Shaft	1,323,000	1,323,000	5,292,000	5,292,000
Equipment	5,000,000	5,000,000	5,000,000	5,000,000
Contingency/Insurance	1,405,000	1,751,000	2,356,000	3,291,000
Interest	2,555,000	3,763,000	6,094,000	9,227,000
Total	11,221,000	13,375,000	21,660,000	28,128,000

Depth to top of cavern - 1500 feet.

Table E-13

COST ELEMENTS: UNCOMPENSATED, SOLUTION MINED CAVERN - 80-12 ATM

Generating Power Rating	150 MW		600 MW	
Generation Time Rating	4 Hours	8 Hours	4 Hours	8 Hours
Geology/Land	$ 668,000	$ 1,018,000	$ 1,838,000	$ 3,238,000
Air Shaft (s)	1,323,000	1,323,000	5,292,000	5,292,000
Equipment	5,200,000	5,200,000	9,800,000	11,336,000
Contingency/Insurance	1,349,000	1,629,000	3,402,000	3,973,000
Interest	1,299,000	2,260,000	3,057,000	5,875,000
Total	9,819,000	11,430,000	23,469,000	29,714,000

Depth to top of cavern - 1500 feet.

Table E-14

COST ELEMENTS: COMPENSATED, SOLUTION MINED CAVERN - 12 ATM

Generating Power Rating	150 MW		600 MW	
Generating Time Rating	4 Hour	8 Hour	4 Hour	8 Hour
Geology/Land	$ 1,884,000	$ 3,484,000	$ 6,736,000	$13,136,000
Water Shaft	409,000	409,000	1,636,000	1,636,000
Air Shaft (s)	696,000	696,000	2,784,000	2,784,000
Equipment/Water Storage	9.572,000	9,572,000	18,000,000	27,000,000
Contingency/Insurance	2,467,000	2,527,000	5,910,000	9,980,000
Interest	2,977,000	4,919,000	6,947,000	13,440,000
Total	18,005,000	21,607,000	42,013,000	67,796,000

Depth to top of cavern - 396 feet.

Table E-15

COST ELEMENTS: COMPENSATED, SOLUTION MINED CAVERN - 40 ATM

Generating Power Rating	150 MW		600 MW	
Generating Time Rating	4 Hour	8 Hour	4 Hour	8 Hour
Geology/Land	$ 655,000	$ 1,055,000	$ 1,871,000	$ 3,471,000
Water Shaft	429,000	429,000	858,000	858,000
Air Shaft (s)	1,023,000	1,023,000	4,092,000	4,092,000
Equipment/Water Storage	4,786,000	4,786,000	15,000,000	15,000,000
Contingency/Insurance	1,384,000	1,415,000	3,785,000	5,123,000
Interest	839,000	1,304,000	3,835,000	7,035,000
Total	9,116,000	10,012,000	29,441,000	35,579,000

Depth to top of cavern - 1160 feet.

Table E-16

COST ELEMENTS: COMPENSATED, SOLUTION MINED CAVERN - 80 ATM

Generating Power Rating	150 MW		600 MW	
Generating Time Rating	4 Hour	8 Hour	4 Hour	8 Hour
Geology/Land	$ 463,000	$ 663,000	$ 1,083,000	$ 1,883,000
Water Shaft	377,000	377,000	1,508,000	1,508,000
Air Shaft (s)	656,000	656,000	2,624,000	2,624,000
Equipment/Water Storage	4,786,000	4,786,000	7,248,000	7,248,000
Contingency/Insurance	1,210,000	1,264,000	2,613,000	3,154,000
Interest	760,000	1,160,000	2,258,000	4,046,000
Total	8,252,000	8,906,000	17,334,000	20,463,000

Depth to top of cavern - 2000 feet.

structure for entrapment will usually be obtained by making geophysical surveys across geologically promising areas. By an analysis of regional and local geology, hydrology, geophysical surveys, and available drilling records, an exploratory drilling program can be developed to better define the subsurface conditions relevant to air storage. The existence of oil or gas fields may indicate the presence of hydrocarbon free structures that may be suitable for compressed air storage.

The number, locations, and depths of exploratory drill holes will be determined by the local conditions and will vary from site to site. Some of the essential information for air storage will include the following:

- Size and shape of the structural trap
- Depth to the cap rock and aquifer (top and bottom contacts)
- Porosity and permeability of the aquifer
- Static water pressure of the storage aquifer, plus determination of water level(s) of overlying aquifers (a difference between aquifer head pressures is useful for determining interformational communication between aquifers)
- Hydrologic conditions such as saturation, water composition (contaminates) etc.
- Reservoir rock homogeneity (vertical and horizontal consistency)
- Hydrodynamic potential differences across the reservoir
- Cap rock permeability (core analysis and in situ testing).

GAS INJECTION

Information relating to the development of a gas "bubble" in a storage reservoir indicates that initial growth is horizontal or concave (downward) discs radiating away from the injection pipe along zones of highest permeability. Several essentially parallel gas discs may radiate outward before the intermediate waters are subjected to displacement by gas. Ultimately the gas pocket will join throughout the length of the injection pipe and expand outward.

During the initial injection of gas, approximately 70 to 80 percent of the formation fluid will be displaced. With subsequent cycles of dry gas the percentage increases, as does the storage capacity of the reservoir.

The displaced water is pushed outward, sometimes as far as several kilometers, until compression of the water and rock matrix equals the volume of space required by the gas. During gas withdrawal, the water-saturated rock surrounding the "bubble" expands to provide a driving force to the exiting gas. It is possible to calculate the reservoir pressure change during a given injection time by using an equation developed by Van Everdingen and Hurst (Ref. 1):

$$t_d = \frac{6.33 \times 10^{-3}\, kt}{M \phi C r_b^2 h},$$

where k = permeability (millidarcys)

t = time (days)

M = viscosity of water (centipoises)

ϕ = porosity, fraction

r_b = bubble radius, feet

c = composite compressibility of water - saturated porous formation

$$c = \frac{\text{volume}}{\text{volume} \times \text{pounds per square inch (psi)}}$$

To estimate the growth of a gas bubble of known thickness and radius the following expression is used:

$$We = 6.283\, \phi\, C r_b^2 h\, (P - Po) Q_t$$

where P > Po

find: * Q_t = td for an infinite aquifer

We = volume of water displaced

*(In an enclosed aquifer such as an isolated sand lens, a different value of Q_t must be used.)

All of the above calculations assume a strict water/gas interface which is not actually the case; however, except for small bubbles, the error is not great and decreases further as the bubble size increases.

During gas injection, the maximum working pressure is based on depth (pressure rise per foot) and the initial aquifer pressure (measured). In gas storage reservoirs, a difference of 100 psi is initially used (until the absence of leakage is confirmed); then a difference of 200 psi or more may be satisfactory.

If too high an injection pressure is used, it is possible to fracture the cap rock formation. Oil and gas stimulation using hydraulic fracturing techniques has shown that fracturing usually occurs at pressures of 0.7 psi/ft to 1.0 psi/ft. Injection pressures of 0.55 psi/ft have been widely used with good success in gas storage reservoirs, and up to 0.7 psi/ft pressures are occasionally used. The selection of suitable injection pressures will vary from reservoir to reservoir, depending on the predetermined geologic/engineering characteristics, reservoir performance tests, and local experience.

Reservoir capacity can be roughly determined using a formula developed by Katz (Ref. 2):

$$Q = 43,560 \; Ah\phi \; (1-S) \frac{PT_b}{P_b Tz}$$

where:
- Q = gas (air) in place, ft^3 measured at P_b and T_b.
- A = areal extent, acres
- h = thickness, feet (distance between top structure contour - bottom structure contour (closing on structure))
- ϕ = fractional porosity
- S = fractional saturation of pore space with water (typically between 0.15 - 0.30)
- P = reservoir pressure, psia
- T = reservoir temperature, °R
- T_b = measured temperature base, °R
- z = compressibility factor, gas (air)

The reservoir thickness (h) can be assumed uniform in many cases; however, when this assumption cannot be used an isopach map of the aquifer (developed from exploration data) can be planimetered to give the gross volume (acre feet). This volume is then used in place of A_h in the above equation.

Differences in hydrodynamic potential from one side of a reservoir to the other side, due to water flowage, can change the effective closure (i.e., tilt the bubble). When this condition exists, the volume, of available storage will either increase or decrease depending on the shape of the reservoir structure.

The dimensions and operational characteristics of an aquifer used for natural gas storage are listed here in order to demonstrate the feasibility of utilization of a similar aquifer for air storage.

Company: Natural Gas Pipeline Co., Kankakee, IL
Trap: Anticline
Native fluid: water
Reservoir data:
  Storage: 6750 acres
  Closure: 8000 acres
  Depth: 1750 feet
  Closure or thickness: 100 feet

Average porosity (%): 18
Average permeability (md): 467

Capacities:

Potential (cushion and working): 50,000 MMCF

Peak daily withdrawal (1973): 812 MMCF

Injection pressure: 680 psig

For comparison, a peaking gas turbine requiring 564 pounds of air per second, or 640 MMCF of air in 24 hours, could easily be supplied with air for a peaking period of from 4 to 10 hours from a comparable reservoir.

The aquifer depth will determine the maximum and minimum storage pressures. Minimum storage pressure can be approximated as equal to 0.433 x depth in feet, 0.433 being the pressure gradient of fresh water in psi/ft. Maximum storage pressure can be approximated as 0.6 psi/ft. This value is taken from data on natural gas aquifer storage practice. Based on the above and using a range of corresponding minimum storage pressures from 20 to 80 atm, a range of aquifer depths is as follows:

	Minimum Pressure (atm)	Minimum Pressure (psia)	Aquifer Depth (ft)
Case 1	20	294	679
Case 2	40	588	1358
Case 3	60	882	2037
Case 4	80	1176	2716

Maximum pressures, assuming the pressure gradient of 0.6 psi/ft is allowed, would be as follows:

	Maximum Pressure (atm/psia)	Pmax-Pmin (atm/psia)
Case 1	27/407	7.7/113
Case 2	55/815	15/227
Case 3	83/1222	23/340
Case 4	111/1630	37/545

Once an aquifer is found at the required depth, then an examination of the other parameters can begin. They will include:

- Presence of an impermeable cap rock
- Aquifer extent (limits of structural trap)
- Porosity of reservoir

- Permeability of reservoir
- Aquifer formation pressure

Much useful data for this search could be accumulated from state and federal geological surveys, and from oil and gas company records. In particular, structures underlain or overlain by oil and gas producing zones should yield much pertinent information.

COST ELEMENTS

The cost elements for aquifers at three different depths are summarized in Tables E-17 through E-19.

Design and costs of air storage in an aquifer with the following characteristics were first determined.

Aquifer depth	1500 feet
Aquifer pressure	1500 x 0.433 = 650 psia = 44 atms
Air injection pressure	650 + 100 = 750 psia = 51 atms
Maximum pressure	1500 x 0.7 = 1050 psia = 71 atms
Minimum pressure	588 psia = 40 atms = turbine inlet pressure
Aquifer permeability	500 md
Aquifer porosity	15%
Stored air temperature	125 F
Aquifer thickness	100 feet

All wells drilled into the aquifer are cased with 13 3/8-inch-diameter casing, providing an internal diameter ~12.5 inches. This casing size (and hole size) can readily be handled by conventional drilling equipment. Given the above conditions, a total of 35 wells should be adequate for both air injection and withdrawal, supplying air to a 150 MW plant. A 600 MW plant would require 4 x 35 - 140 wells. Well completions would start at the crest of the anticline and proceed outwards. Well spacing would be 350 feet (107 meters). Air collection costs are based on a rectangular well array without valves or well chokes to match well flow. Because the manifold terminates at the well in 6-inch pipe, it is potentially economical to install a valve on each well.

DEVELOPMENT TIME

Starting with an air injection pressure 7 atms (100 psi) greater than reservoir pressure, some six to eight months would be required to charge the aquifer for the 150 MW, 4 hour storage case. Assuming 26.2×10^6 scf of air required for one hour operation (2×10^6 lbs air), a 4 hour cycle requires 525×10^6 SCF air in storage. The ratio of total air to usable air is chosen as 5:1. This gives an air "cushion" interposed between the usable

Table E-17

COST ELEMENTS: AQUIFER 12 ATM

Generating Power Rating	150 MW		600 MW	
Generating Time Rating	4 Hour	8 Hour	4 Hour	8 Hour
Geology/Land	$ 740,000	$ 1,030,000	$ 2,250,000	$ 2,610,000
Well Completion	5,870,000	5,870,000	23,480,000	23,480,000
Bubble Development	400,000	463,000	775,000	1,250,000
Air Collection	1,723,000	1,723,000	7,562,000	7,562,000
Contingency/Insurance	1,790,000	1,863,000	6,984,000	7,155,000
Interest	1,206,000	1,278,000	6,295,000	6,496,000
Total	11,729,000	12,227,000	47,346,000	48,552,000

Depth to bottom of aquifer - 500 feet.

Table E-18

COST ELEMENTS: AQUIFER 40 ATM

Generating Power Rating	150 MW		600 MW	
Generating Time Rating	4 Hour	8 Hour	4 Hour	8 Hour
Geology/Land	$ 960,000	$ 980,000	$ 1,230,000	$ 1,290,000
Well Completion	4,340,000	4,340,000	17,360,000	17,360,000
Bubble Development	1,395,000	1,520,000	1,780,000	2,285,000
Air Collection	1,538,000	1,538,000	6,154,000	6,154,000
Contingency/Insurance	1,688,000	1,717,000	5,437,000	5,553,000
Interest	1,031,000	1,045,000	4,733,000	4,793,000
Total	10,952,000	11,141,000	36,695,000	37,435,000

Depth to bottom of aquifer - 1500 feet.

Table E-19

COST ELEMENTS: AQUIFER 80 ATM

Generating Power Rating	150 MW		600 MW	
Generating Time Rating	4 Hour	8 Hour	4 Hour	8 Hour
Geology/Land	$ 1,110,000	$ 1,120,000	$ 1,270,000	$ 1,330,000
Well Completion	4,240,000	4,240,000	17,960,000	17,960,000
Bubble Development	3,400,000	3,545,000	3,835,000	4,435,000
Air Collection	1,623,000	1,623,000	6,492,000	6,492,000
Contingency/Insurance	2,126,000	2,158,000	6,059,000	6,194,000
Interest	1,211,000	1,224,000	5,086,000	5,153,000
Total	13,710,000	13,910,000	40,703,000	41,564,000

Depth to bottom of aquifer - 2700 feet.

air and the water front in the aquifer. After charging the aquifer with air, it should by cycled daily for observation of air delivery rate and air quality. Consideration should be given to drying the air before injection, in which case the interstitial formation water will be removed more rapidly, thereby improving reservoir porosity, permeability, and air delivery rate. A six month air cycling period is suggested.

It should be possible to drill and complete a 1500 foot (457 meter) well in 20 days requiring a total of two years to drill the required wells if only one rig were used. With two rigs, and with air injection proceeding simultaneously with drilling, the aquifer should be ready for production in 2 1/2 years, allowing one year for water displacement and air cycling. The costs of air injection are based on the approach described by Katz (Ref. 3). The average cost of power for bubble development was assumed to be 30 mills/kWh, since using offpeak power only would extend the development time uneconomically. The investment in pumping equipment is based on $300/hp with a 20 percent salvage value.

EXPLORATION COSTS

A six month geologic survey should be adequate to delineate known potential structures and lay the groundwork for more thorough structure evaluation. Up to 25 test holes will be required in order to contour the structure. A minimum of three holes, drilled through the structure, will be required. Cores will be taken through the cap rock and underlying aquifer. The cores will be examined for cap rock integrity and aquifer permeability and porosity. Drill stem tests will be run on the holes drilled through the aquifer and used to calculate formation fluid transmissibility.

Cap rock integrity will be tested by pumping water from the aquifer while simultaneously observing the water level in the formation immediately above the cap rock. This test could consume up to three months time.

In all, it is estimated that up to two years will be required to select and test an aquifer followed by 2 1/2 years for aquifer development, for a total of 4 1/2 years from project initiation to full aquifer development for the 150 MW 4 hour plant.

OTHER CONSIDERATIONS

The effect of varying turbine inlet pressure, either above or below the 40 atm (488 psia) case outlined above, will not significantly affect drilling or exploration costs. For example, at 12 atm (176 psia) the number of wells required triples, although the total footage drilled and the total well casing required remains approximately the same. The acreage required, however, approximately triples.

On the other hand, air storage at 80 atm (1176 psia) requires fewer wells and fewer acres. Development time for the high pressure deep aquifer is significantly less than for the shallower, low pressure aquifers.

It should be borne in mind that it is unlikely that an aquifer can be found that will exactly match the turbine inlet pressure requirements. Costs of compression will be unnecessarily high if a deep, high pressure aquifer is used to supply a low inlet pressure turbine. In other words, it will be necessary to tailor the compressor train and turbine inlet pressure to the aquifer storage pressure, rather than the other way around.

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E-2. Katz, D. L., Cornell, D., Kobayashi, R., Poettman, F. H., Vary, J. A., Elenbaas, J. R., and Weinang, C. F., Handbook of National Gas Engineering, McGraw-Hill Book Co. Inc., New York, N. Y., 1959.

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Appendix F

CHARACTERISTICS OF THE BROOKVILLE SITE

F.1 SURFACE FEATURES

The Brookville Dome is located in western Ogle County, adjacent to the Ogle-Carroll county line (Figure 7-2 of this report). The unincorporated rural community of Brookville and the village of Polo are located north and southeast, respectively, of the dome and are beyond the limits of structural closure and the ultimate limit of the storage area (Figure 7-3). The nearest large city, Rockford, Illinois (population 136,000), is located approximately 35 miles northeast of the site. The proposed storage area, shown in Figure 7-3 of this report, covers approximately 4195 acres in Ogle County and includes all or portions of Sections 34 and 35 of T-24N, R7E, Brookville Township; Sections 1, 2, 3, 10, 11, 12, 13, and 14 of T-23N, R7E, Eagle Point Township; and Sections 6, 7, and 18 of T-23N, R8E, Buffalo Township.

Access to the site is possible at all times of the year via U.S. Highway 52 and improved, interconnecting country roads. The area is served by the Illinois Central and the Chicago, Burlington, and Quincy Railroads. Railroad access will be provided by constructing a railroad spur that intersects one of these lines. Utilities are available as follows:

- Water for potable use, construction activities, and the closed-cycle cooling system makeup can be provided by a well or wells in the aquifer.
- Communication lines must be furnished to the site boundaries.
- Power for construction activities is available at the site boundary.

Physiographically, the proposed storage area is in the Rock River Hill country. The uplands are bedrock controlled and developed on rock formations of Middle Ordovician Age. Surface materials in the Brookville region are soils and alluvium which have been derived from and developed on a relatively thin mantle of glacial drift deposited by Illinoian ice. The soil zones and underlying glacial deposits of clay, sand, and gravel range in thickness from 8 to 75 feet in wells drilled and logged in the area.

Surface elevations in the area range from 940 feet above sea level on the crest of the structure to 760 feet along the northeast-southwest-trending valley of Elkhorn Creek, which lies beyond the northern limits of closure, and to 800 feet above sea level on the south end of the area. Drainage of the area is accomplished by Elkhorn Creek and numerous small tributaries on the northwest and by Eagle Creek on the south (see Figure 7-3). At the proposed CAES plant, sewage would be treated on site and the clarified and chlorinated effluent discharged into Elkhorn Creek.

F.2 STRUCTURE

A number of major structural features are present in this area of northern Illinois (Figure F-1). The most important of these are: the Wisconsin arch, the Savanna anticline, and the LaSalle anticline. The Wisconsin arch is a large, positive structural feature that trends in a general north-south direction, plunging gently southward, from central Wisconsin into northern Illinois, where it appears to merge with the LaSalle anticline in south-central Ogle County. The Savanna anticline trends in an east-west direction and merges with the Wisconsin arch in northern Ogle County. This anticline plunges to the west and is asymmetrical, with the steeper flank to the north. Although the exact structural relationships are obscure, the LaSalle anticline appears to be a southern continuation of the Wisconsin arch and trends southeastward into the Illinois basin.

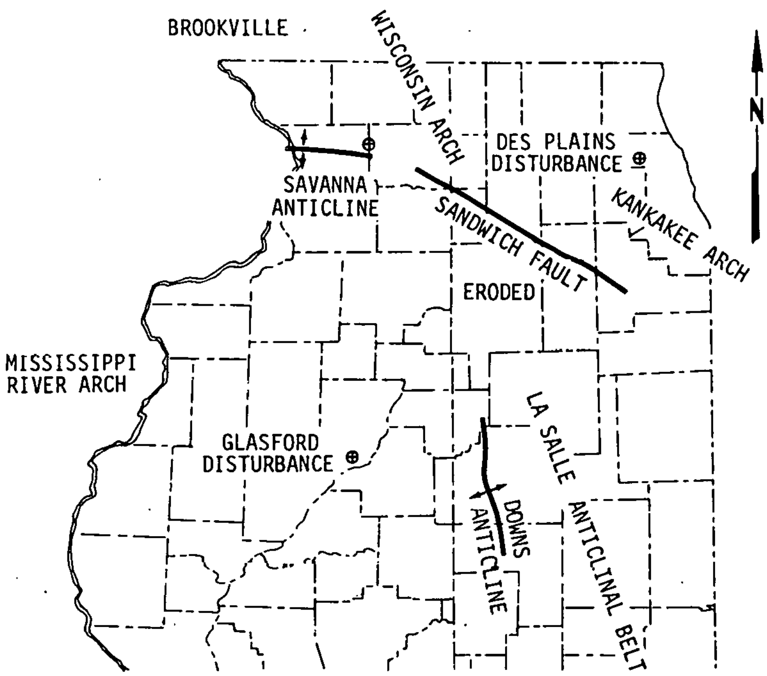

Figure F-1. Structure on Top of Galena Group in Northern Illinois

In general the structures in the Brookville uplift area are believed to have originated by northward and/or northeastward compressive forces related to the Illinois and Forest City basins. The major structural movements in the area have been suggested as post-Mississippian, pre-Pennsylvanian, followed by lesser uplift in post-Pennsylvanian time. Tectonic activity, at least in recent time, appears to be relatively quiescent, the major stratigraphic alteration having been carried out as a result of glaciation and its attendant glacial deposition mechanisms. This would tend to indicate that the area is reasonably secure structurally for a compressed air storage facility.

Several second and third order folds, in this area of relatively strong uplift near the junction of the Savanna anticline and the Wisconsin arch, have resulted in the anticlinal feature known as the Brookville Dome. Figure F-2, a cross section from central Carroll County to eastern Cook County, illustrates the relationship of the Brookville structure to the Wisconsin arch and all of northern Illinois. The Brookville structure lies on the western flank of the arch, essentially away from the Chicago area and its associated draw-down problems, which are discussed later in this appendix under "Potenial Aquifer Drawdown Problems."

The Brookville Dome is a northwest-southeast trending structure, closed on both ends. The northwest closure is the steeper of the two; 128 fpm* on the northwest versus 45 fpm on the southeast. The northeast flank has a dip of 196 fpm versus 96 fpm on the southwest, possibly indicating the presence of a fault off the northeast flank. The available data do not indicate such a fault; this can be confirmed only by exploration drilling as outlined later in this appendix, under "Procedure for Site Exploration." The crest of the structure, based on the top of the Ironton-Galesville formation, lies at a subsurface depth of 672 feet (+253 feet sea level datum). The north flank of the structure lies at a subsurface depth of 701 feet (+119 feet sea level datum). The closure limit lies at the same sea level depth as the north flank, +119 feet. The dome has an available storage pore volume of 4.4 billion cubic feet based on an areal extent of 4193 acres, with 134 feet of formation closure at an assumed porosity of 18 percent. Figure F-3 and the associated cross section in Figure F-4 illustrate the area extent and shape of the structure.

F.3 STRATIGRAPHY

Rock in the Brookville area ranges from Pleistocene clays down to the Mt. Simon sandstone, which is the deepest penetrated sandstone. Table F-1, modified after Csallany and Walton (Ref. 2), gives the stratigraphy, description, drilling conditions, and water-yielding properties of the general strata of northern Illinois.

The Pleistocene system in the area of interest is composed of unconsolidated clays, silt, and gravel depositied by glaciation moving through the area in recent time. The variation in thickness (from 8 to 79 feet) in the area reflects a deeply eroded surface on the bedrock, a surface carved primarily by streams before the advent of the Pleistocene glaciation.

Beneath the glaciated deposits lie bedrock formations consisting mainly of dolomites, shales, and sandstones which dip southwesterly off the flanks of the Wisconsin arch. Bedrock formations in the Brookville site area range in age from Ordovician to Cambrian, although deeper formations are recorded from wells in other parts of northern Illinois. Youngest of the strata encountered is the Ordovician Galena Group, since all younger rocks have been eroded away within the limits of closure. Table F-2 shows the contiguous

*feet per mile

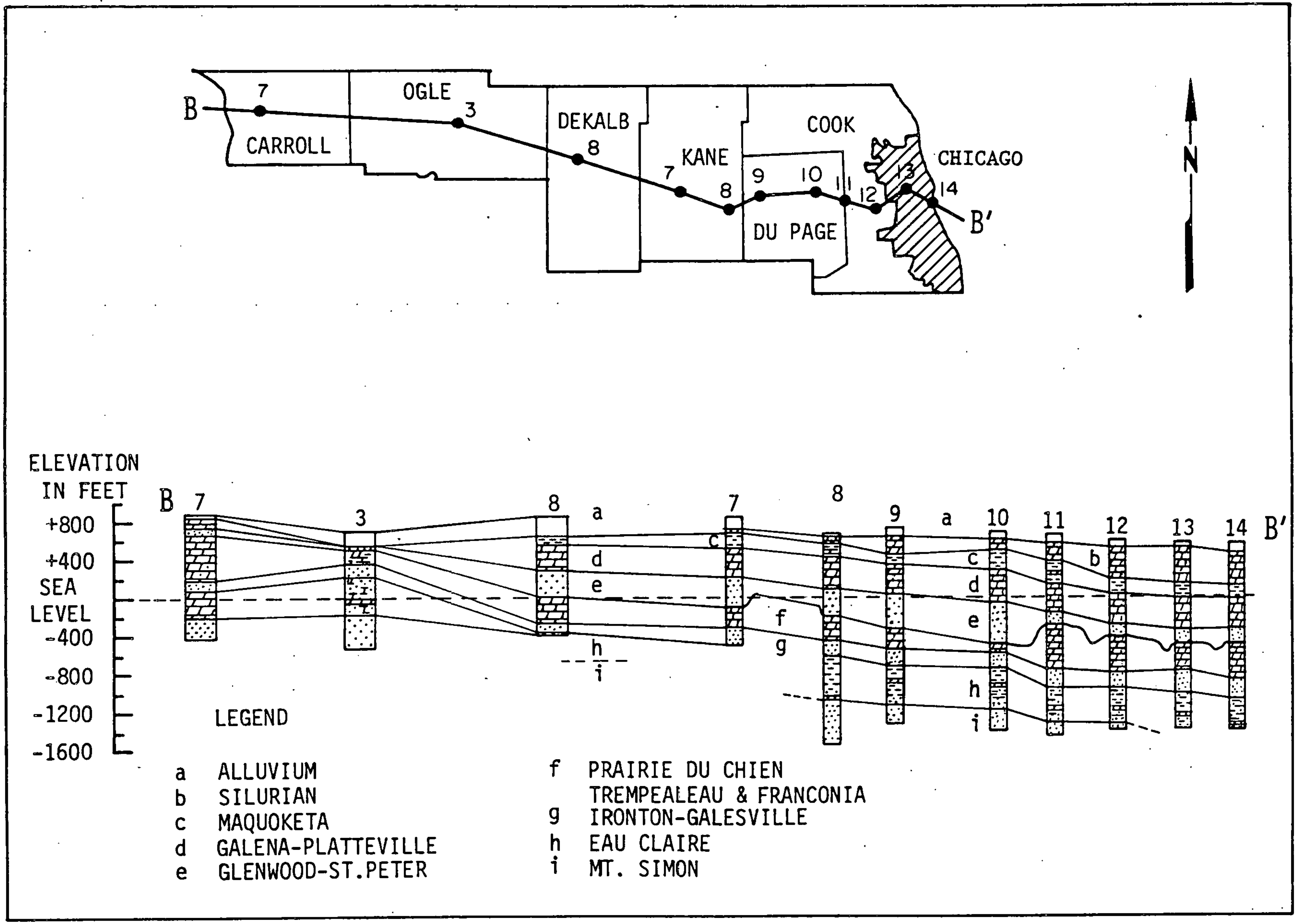

Figure F-2. Cross Sections of the Structure and Stratigraphy of the Bedrock in Northern Illinois

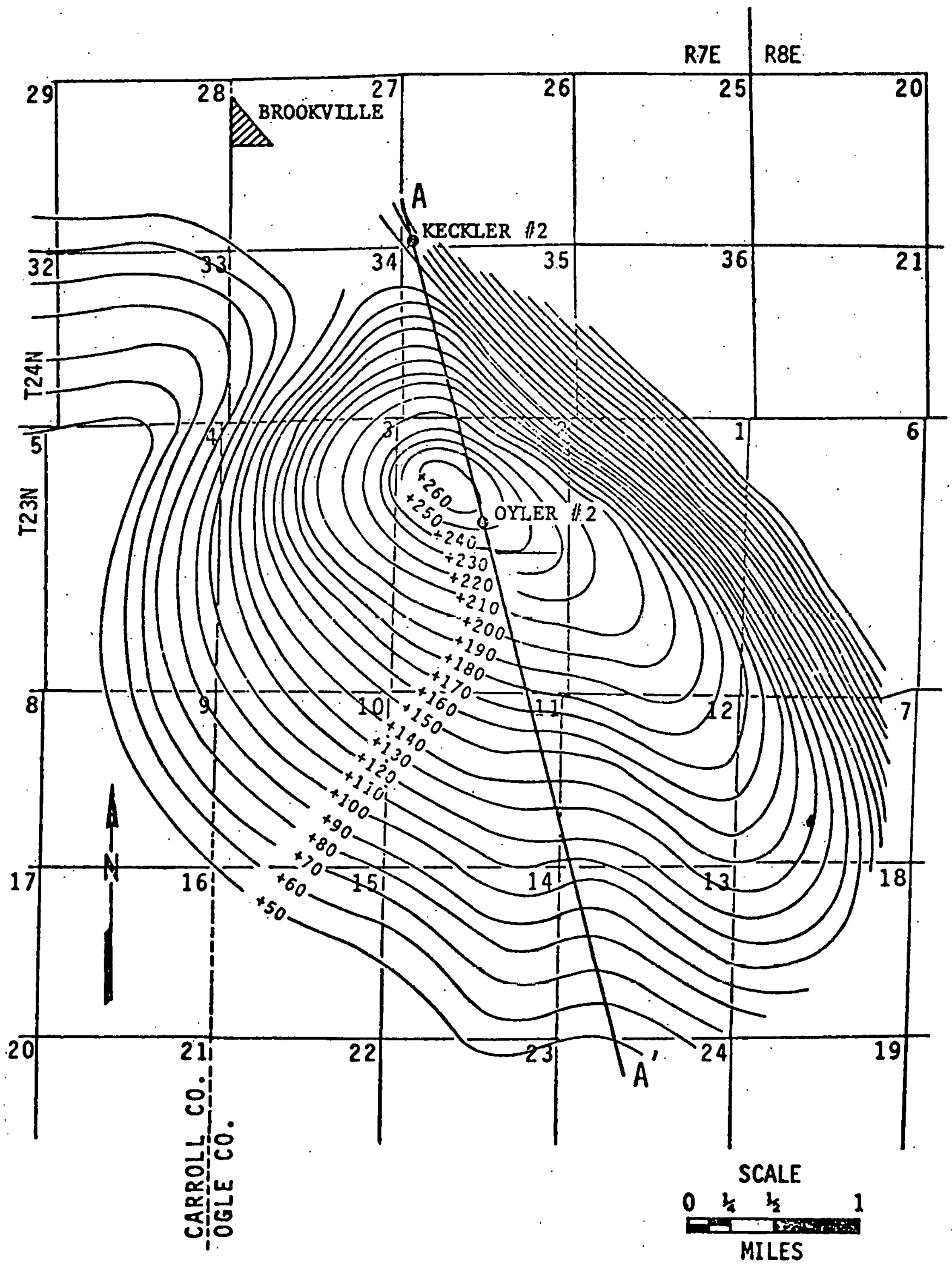

Figure F-3. Plan View of Top of Ironton-Galesville Formation at Brookville

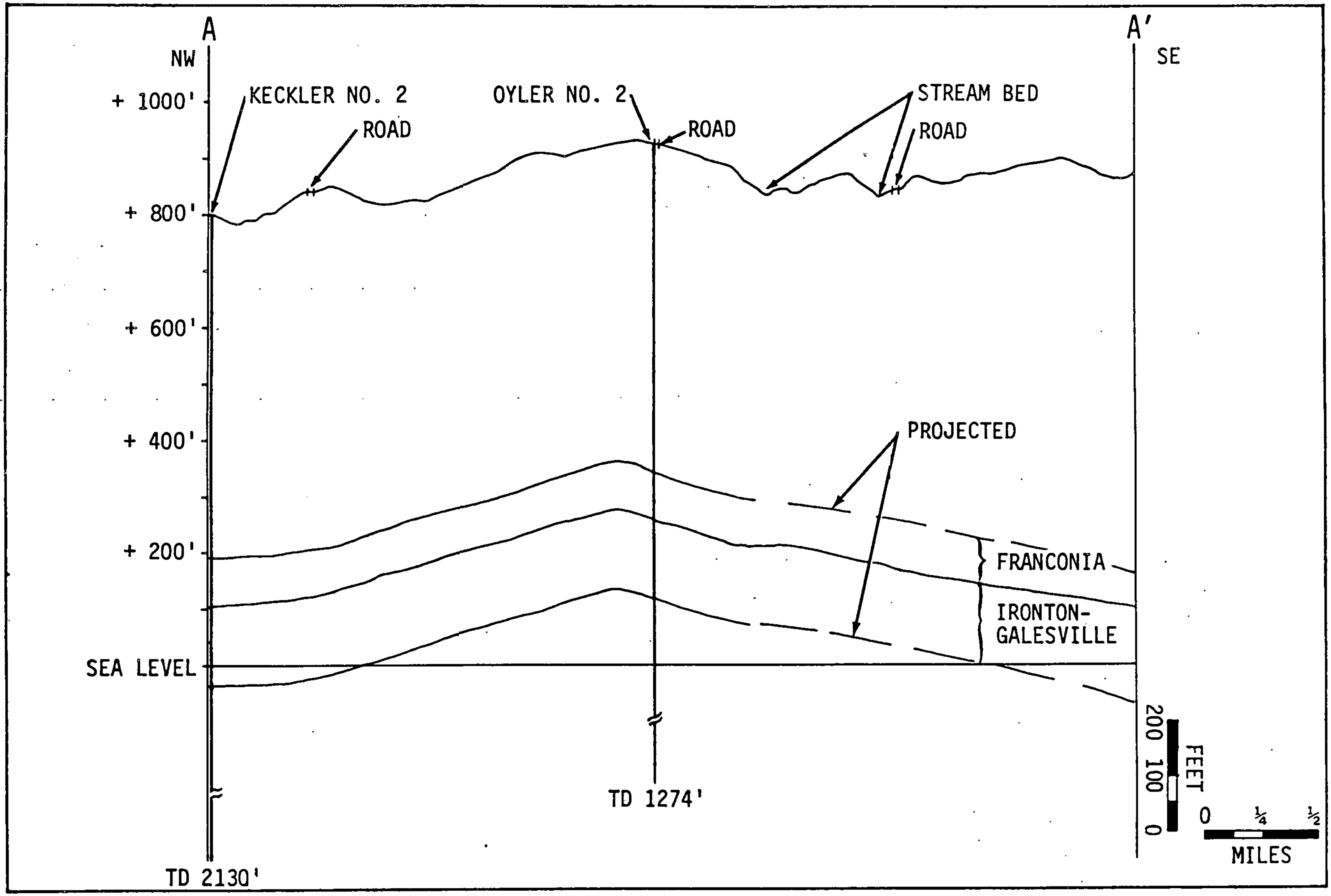

Figure F-4. Northwest-Southeast Cross Section on Brookville Dome Showing Relation of Franconia to Ironton-Galesville

Table F-1

GENERALIZED STRATIGRAPHY AND WATER-YIELDING PROPERTIES OF ROCKS IN NORTHERN ILLINOIS (Ref. 2)

SYSTEM	SERIES	GROUP OR FORMATION	GEOHYDROLOGIC UNITS	LOG	APPROXIMATE RANGE IN THICKNESS (ft)	DESCRIPTION	DRILLING AND CASING CONDITIONS	WATER-YIELDING PROPERTIES
Quaternary	Pleistocene		Glacial drift aquifers		0-500	Unconsolidated clay, silt, sand, gravel, and boulders deposited as till, outwash, pond water deposits, and loess	Boulders, heaving sand locally; sand and gravel wells usually require screens and development; casing required in wells into bedrock	Probabilities for ground-water development range from poor to excellent; outwash sand and gravel yield more than 1000 gpm to wells at places; large supplies generally obtained from permeable outwash in major valleys; glacial aquifers used for many small water supplies because they are shallow
Pennsylvanian		McLeansboro Carbondale Tradewater Caseyville			0-600	Mainly shale with thin limestone, sandstone, and coal beds	May require casing because of shale caving and poor-quality water	Generally unfavorable as an aquifer; locally domestic and farm supplies obtained from thin limestone and sandstone beds
Mississippian	Valmeyer	St. Louis-Salem			0-100	Limestone		Water yielding where creviced; too thin to be important source of water in most of area
		Warsaw			0-100	Shale	Casing required	Not water yielding at most places
		Keokuk-Burlington			0-200	Cherty limestone		Generally creviced and water yielding; dependable aquifer for small supplies in western Illinois
	Kinderhook				0-300	Shale with limestone and dolomite	Casing required	Not water yielding at most places; locally limestones within shale are source of small farm supplies
Devonian					0-200	Thin limestone, shale, & sandstone beds		Not normally a source of water because of a lack of cracks or solution openings
Silurian	Niagaran	Port Byron Racine Waukesha Joliet	Silurian (Shallow dolomite aquifers)		0-500	Dolomite; silty at base, locally cherty	Upper part usually weathered and broken; extent of creviciing varies widely	Some wells yield more than 1000 gpm; not consistent; crevices and solution channels more abundant near surface
	Alexandrian	Kankakee Edgewood						
Ordovician	Cincinnatian	Maquoketa	Maquoketa		0-250	Shale, gray or brown; locally dolomite and/or limestone, argillaceous	Shale requires casing	Shales, generally not water yielding, act as confining beds between shallow and deep aquifers; crevices in dolomite yield small amounts of water
	Mohawkian	Galena Decorah Platteville	Galena-Platteville (Bedrock aquifers)		220-350	Dolomite and/or limestone, cherty, sandy at base, shale partings	Creviciing common only where formations underlie drift; top of Galena usually selected for hole reduction and seating of casing	Where formation lies below shales, development and yields of crevices are small; where not capped by shales, dolomites are fairly permeable
		Glenwood	Glenwood-St. Peter		50-650	Sandstone, fine- and coarse-grained; little dolomite; shale at top	Lower cherty shales cave and are usually cased; friable sand may slough	Small to moderate quantities of water; coefficient of transmissibility probably averages about 15 percent of that of Cambrian-Ordovician aquifer
	Chazyan	St. Peter				Sandstone, fine- to medium-grained; locally cherty red shale at base		
	Prairie du Chien	Shakopee New Richmond Oneota	Prairie du Chien (Cambrian-Ordovician aquifer)		0-400	Dolomite, sandy, cherty; sandstone. Sandstone interbedded with dolomite, white to pink, coarse-grained, cherty, sandy		
Cambrian	St. Croixian	Trempealeau	Trempealeau		0-225	Dolomite, white, fine-grained, geodic quartz, sandy at base	Crevices encountered locally in the dolomite, especially in Trempealeau; casing generally not required	Crevices in dolomite and sandstone generally yield small to moderate quantities of water; Trempealeau locally well creviced and partly responsible for exceptionally high yields of several deep wells; coefficient of transmissibility probably averages about 35 percent of that of Cambrian-Ordovician aquifer
		Franconia	Franconia		45-175	Dolomite, sandstone, and shale glauconitic, green to red, micaceous		
		Ironton Galesville	Ironton-Galesville		105-270	Sandstone, fine- to medium-grained, well sorted, upper part dolomitic	Amount of cementation variable; lower part more friable; sometimes sloughs	Most productive unit of Cambrian-Ordovician aquifer; coefficient of transmissibility probably averages about 50 percent of that of Cambrian-Ordovician aquifer
		Eau Claire	Eau Claire (upper and middle beds) lower beds		235-450	Shale and siltstone, dolomitic, glauconitic; sandstone, dolomitic, glauconitic	Casing not usually necessary; locally weak shales may require casing	Shales generally not water yielding; act as confining bed between Ironton-Galesville and Mt. Simon
		Mt. Simon	Mt. Simon (Mt. Simon aquifer)		1000-2000±	Sandstone, coarse-grained, white, red in lower half; lenses of shale and siltstone, red, micaceous	Casing not required	Moderate amounts of water; permeability intermediate between that of Glenwood-St. Peter and Ironton-Galesville
Precambrian crystalline rocks								

[Modified after Csallany and Walton, 1963 (4)]

Table F-2

STRATIGRAPHY AT THE BROOKVILLE SITE

PLEISTOCENE	
Ordovician System	Cambrian System
Champlainian Series	Croixian Series
Galena Group	Eminence formation
Dunleith formation	Potosi formation
Guttenberg formation	Franconia formation
Spechts Ferry formation	Ironton formation
Platteville Group	Galesville formation
Quimbys Mill formation	Eau Claire formation
Nachusa formation	Mt. Simon formation
Grand Detour formation	
Mifflin formation	
Pecatonica formation	
Ancell Group	
Glenwood formation	
Harmony Hill member	
Daysville member	
Kingdom member	
St. Peter formation	
Tonti member	
Kress member	
Canadian Series	
Prairie du Chien Group	
Shakopee formation	
New Richmond formation	
Oneota formation	
Gunter formation	

strata encountered in the area of interest, and the following paragraphs provide a brief description of these strata.

ORDOVICIAN SYSTEM

Galena Group

Recognition of the various formations of the Galena has not been successful. Local dolomitization has obscured, if not obliterated, many of their distinctive characteristics. It is primarily a buff, light gray dolomite. Some Galena is encountered on the flanks of the structure, but none on its crest.

Platteville Group

The Platteville Group is separated by a regional unconformity from the overlying Galena Group. In the Platteville, as in the Galena, dolomitization has obscured many of the distinctive characteristics.

Ancell Group

The Ancell Group in the Brookville area is composed of the Glenwood formation and the St. Peter sandstone.

Glenwood Formation. The Glenwood formation includes all strata between the overlying Platteville Group and the underlying St. Peter formation.

The Harmony Hill shale member is soft, green to grayish-green, and maintains a uniform thickness of 5 feet throughout the area.

The Daysville dolomite member consists of 4 feet of gray to greenish-buff, argillaceous, very sandy dolomite, which locally grades laterally into dolomitic cemented sandstone.

The Kingdom sandstone member is approximately 10 feet thick and is a pale green to greenish-gray, silty, argillaceous, friable sandstone. The Kingdom unconformably overlies the Tonti member of the St. Peter sandstone.

St. Peter Sandstone. In the Brookville area, the St. Peter sandstone is subdivided into two members: the basal Kress member and the Tonti member.

The Tonti sandstone member consists of fine to medium grained, rounded, and friable quartz sandstone which is remarkably pure. It ranges in thickness from 45 to 60 feet in the Brookville area.

The Kress member is a course, basal conglomerate of clay, shale, sand and chert. Although in the immediate Brookville area the conglomeratic texture appears poorly preserved, the member is recognized by relatively thin beds of green shale. The Kress member directly and unconformably overlies the Shakopee formation of the Prairie du Chien Group. Considerable irregularity occurs in the thickness of the St. Peter as a result of the major unconformity. Erosion and/or solution collapse of the Prairie du Chien carbonates prior to or during St. Peter deposition have resulted in changes of several hundred feet in relief on the base of the St. Peter. However, since the increase in St. Peter thickness is accompanied by a corresponding decrease in upper Prairie du Chien thickness, the compensation has no effect on the uniformity of the interval from the Glenwood-Upper St. Peter to the top of the various Upper Cambrian formations.

Prairie du Chien Group

Composed of four sandstone and dolomite members, the Prairie du Chien Group is divided as follows.

Shakopee Dolomite. The Shakopee dolomite is a variable unit of very fine-grained dolomite, thin beds of sandstone, green shale partings, and chert nodules. A few thin beds of coarse grained, porous dolomite are also present.

New Richmond Sandstone. The New Richmond sandstone consists of sandstone and dolomite. The sandstone is dolomitic, medium to fine grained, subrounded, and slightly friable. The dolomite is sandy, light pinkish-gray, very fine grained, and includes sandy and oolitic chert.

Oneota Dolomite. The Oneota dolomite consists of light gray to light brown, medium grained, cherty dolomite. Some zones have 1/4 to 1/2 inch vugs that contain calcite, quartz crystals, drusy dolomite, or soft white silica. Green shale partings are common.

Gunter Sandstone. The Gunter sandstone consists of a medium grained sandstone and some dolomite, with thin minor partings of green shale.

CAMBRIAN SYSTEM

Eminence Formation

The Eminence formation consists of light gray to light brown, fine to medium grained, sandy dolomite that contains oolitic chert. Dolomitic sandstone is present both in beds 10 to 14 feet thick and in thin stringers. The Eminence is about 30 feet thick in this area.

Potosi Dolomite

The Potosi dolomite is a light grayish-brown, fine grained, slightly glauconitic dolomite. This formation is characterized by drusy quartz.

Franconia Formation

The Franconia formation consists of fine grained glauconitic sandstone, fine grained sandy dolomite, and silty green shale. The formation is characterized by abundant glauconite. The Franconia is about 80 feet thick at the Brookville site. Southward, it thickens and becomes less sandy. The upper part of the Franconia grades into the Derby-Doerun dolomite of Missouri. The lower, shaly unit is correlated with the Davis formation of Missouri.

Ironton-Galesville Sandstone

The Ironton-Galesville sandstone consists chiefly of medium grained, friable, slightly dolomitic sandstone. At the top there is 20 feet of sandy glauconitic dolomite. Both the sand and glauconite are much coarser grained than in the overlying Franconia formation. The Ironton-Galesville Sandstone, 100 to 200 feet thick throughout most of northern Illinois, is approximately 140 feet thick in this area.

Eau Claire Formation

The Eau Claire formation is a variable unit of sandstone, siltstone, and shale. The sandstone is silty, dolomitic, glauconitic, micaceous and fossiliferous. The siltstone is grayish orange, micaceous and compact. The shale is silty, green to red, micaceous, and brittle. The shale is most abundant near the middle of the formation. The Eau Claire is about 300 feet thick in the Brookville area, where it is in a predominantly sandstone facies. It thickens markedly southeastward.

Mt. Simon Sandstone

The Mt. Simon sandstone consists of fine to coarse grained, poorly sorted, friable sandstone. Some zones are compact and well cemented by silica or hematite. It is essentially nondolomitic and nonglauconitic. The upper half of the Mt. Simon contains some interbedded red and green shale; the lower part of the formation is pink and arkosic. The amount of feldspar increases downward.

Since this report deals with compressed air storage in the Ironton-Galesville formation, a detailed discussion of the Franconia formation and the Ironton-Galesville formation follows.

FRANCONIA FORMATION

The Franconia sandstone lies conformably below the Potosi dolomite. The formation is at a depth of 592 feet below the crest of the dome and maintains a uniform thickness of 85 feet throughout the area. It consists of fine grained, glauconitic sandstone with thin beds of gray-green shale and finely crystalline dolomite. Although the Franconia formation is sandy, sandstone actually comprises less than half of the formation at most places; at least half the beds are gray-green shale or sandy dolomite. The sandstone beds commonly contain more dolomite and glauconite and are finer grained than the underlying Ironton and Galesville sandstones. Where the top few feet of the Franconia is dolomite it cannot be easily distinguished from the Potosi dolomite, which also tends to be sandy in its lower part, but the streaks of slightly greenish sandstone which invariably show in the upper Franconia allow easy identification of that formation as drilling progresses.

Water-Yielding Characteristics

The Franconia is not a significant ground water source in deep, high-capacity wells in most of northern Illinois except near the Wisconsin line, where its sandstone beds are apparently thicker, cleaner, and more permeable than in areas to the south. The limited permeability of the Franconia sandstone probably is due largely to its dolomite content and firmness.

Drilling Characteristics and Well Construction

No special drilling problems are normally associated with the Franconia formation in the Lee-Whiteside region. Drilling time is reported to be slow in sandstone beds tightly cemented with dolomite. The shale beds are more firm than the Maquoketa shale, for example, and casing a well to maintain an open hole is not usually necessary.

Because the Franconia formation is normally overlain and underlain by favorable water-bearing beds (the Potosi dolomite above and the Galesville sandstone below), the only wells designed to tap Franconia beds are located in T-39N, R1E in northeastern Lee County, where the formation lies directly below tight glacial drift. No Franconia water wells are known to exist in the Brookville area.

Cap Rock Integrity

Little is known about the integral makeup of the Franconia as far as its structural ability to contain a stored product is concerned. That is, no testing of the Franconia has been done to date to determine its effective permeability, porosity, and transmissivity, if any. In the documentation of the unsuccessful storage attempt it was noted that gas did migrate up to the Ironton-Galesville, but no mention is made of any stratigraphically higher gas detection. Also, subsequent venting of the lost gas was done from perforations in the Ironton-Galesville formation. It seems reasonable to assume that the Franconia may be a safe cap rock for the storage of air in the Ironton-Galesville formation. Documentation of the unsuccessful storage attempt indicated that gas was vented from the Ironton-Galesville formation until the wells would no longer flow (1966-1969). However, it was also noted in discussion with the Natural Gas Pipeline Company of America that venting from the Ironton-Galesville formation was finally stopped in the summer of 1974 and the wells shut in (Ref. 1).

The fact that at least 894 million cubic feet of gas were injected in 1966 and that venting took place from 1966 until the summer of 1974 would tend to confirm the Franconia formation as a reasonable cap rock. However, it must be noted that additional field research will be required to substantiate this assumption.

IRONTON-GALESVILLE FORMATION

Occurrence

The Ironton-Galesville sandstone has been found in almost all borings in northern Illinois that have penetrated below the Franconia formation. It is approximately 140 feet thick and in this area is underlain by the Eau Claire shales and sandstones. Like most bedrock formations in this region, this sandstone dips gently southwestward from central Ogle County. The top of the Ironton-Galesville is about 673 feet deep on the crest and about 740 feet deep on the flank. The top can be recognized by a change from thin, dolomitic, greenish-gray sandstone (Franconia) to lighter gray, softer, locally reddish sandstone (Ironton). The base of the Galesville is recognized by a change to a dark hard shale 10 to 25 feet thick (upper Eau Claire).

Water-Yielding Characteristics

The Ironton-Galesville beds have long been considered the most favorable deep rock aquifer in Illinois. The generally good water-yielding characteristics of this sandstone result from a number of geologic conditions:

- The sandstone has several zones with good to excellent permeability, comprising up to half the thickness of the formation at some locations.
- The zones of good permeability appear to have wide lateral extent.
- The sandstone has more or less uniform thickness over thousands of square miles.
- Recharging can take place in some areas in step-like fashion through overlying formations, particularly in that portion of northern Illinois where the Maquoketa shale is not present to bar surface infiltration.
- The southerly dip of the formation, together with hydrologic interconnection with overlying water-bearing beds, has created naturally high water-pressure potential.

The Ironton-Galesville sandstone is popular in northern Illinois as a source of municipal and industrial ground water, not only because of its favorable water-yielding characteristics but also because of its widespread occurrence.

This enables well sites to be selected largely on the basis of convenience. Furthermore, the Ironton-Galesville formation is sufficiently consistent to enable well specifications to be drawn in advance of drilling. Regardless of the shortcomings of rigid well specifications, they are apparently desirable from an economic standpoint and are an attractive feature of the development of the Ironton-Galesville sandstone as opposed to surficial sand and gravel or to the shallower dolomites.

Shooting the Ironton-Galesville sandstone with explosives to increase yield is common practice in northeastern Illinois. If shooting zones are carefully selected on the basis of sample studies and/or electric logs, the bore hole can be enlarged to several times the diameter of the bit and a marked increase in yield will be noted. This method requires extensive well cleaning, after shooting, to reopen the well to its original depth. Shooting is probably best adapted to rehabilitating old wells or to improving new wells that show a disappointing specific capacity.

Drilling Characteristics and Well Construction

Drillers report that the Ironton-Galesville sandstone presents no serious problems in drilling. Because there is considerable caving, the formation is treated like the St. Peter sandstone -- short drilling intervals and frequent and thorough bailing. This hazard is not so great as in the St. Peter, possibly because there is less contrast between weak and firm beds. Caliper logs of deep wells in many parts of northern Illinois show that, even without shooting a bore hole in the Ironton-Galesville sandstone is often enlarged to 2 to 4 times the bit diameter by spontaneous caving. This characteristic is probably very significant in the yield of deep sandstone wells. These zones of caved sandstone may also be important in trapping fine grained sand and silt during pumping, because the enlarged hole causes a loss of water at that zone.

Gas Storage

Storage of gas has proved to be successful in the Ironton-Galesville formation in the Shanghai gas field of Warren and Mercer Counties, Illinois. There, with 1900 acres in the domal area, the reservoir will hold an estimated 11 billion cubic feet of gas at 50 psi above static formation pressure. No major problems have been encountered with the storage aquifer. Projected ultimate delivery of the storage aquifer is 136 million standard cubic feet per day from 16 wells (Ref. 3).

F.4 HYDROLOGY

AREA AQUIFER USAGE

Ground water resources in northern Illinois are developed from four aquifer systems:

- Sand and gravel deposits of the glacial drift.
- Shallow dolomite aquifers of Silurian and Ordovician Ages.
- Sandstone aquifers of Cambrian and Ordovician Ages, of which the Ironton-Galesville and Glenwood-St. Peter sandstones are the most productive formations.
- Mt. Simon aquifer, consisting of sandstones of the Mt. Simon and lower Eau Claire formations of the Cambrian Age. The sequence, structure, and general characteristics of these rocks are shown in Table F-1.

On a regional basis the Ironton-Galesville sandstone is the most consistently permeable and productive unit of the Cambrian and Ordovician rocks. Many of the high-capacity municipal and industrial wells in northern Illinois obtain a major part of their yields from this formation (Ref. 9).

In Ogle County during the period of 1960 through 1970, total ground water pumpage rose from 8 million to a high of 11 million gallons per day in 1965 and then declined to 10.62 in 1970 (see Figure F-5). In adjacent Carroll County during the same period, ground water pumpage changed little from 3.99 in 1960 to a net overall increase of about 5 percent in 1970, totaling 4.20 (see Figure F-5).

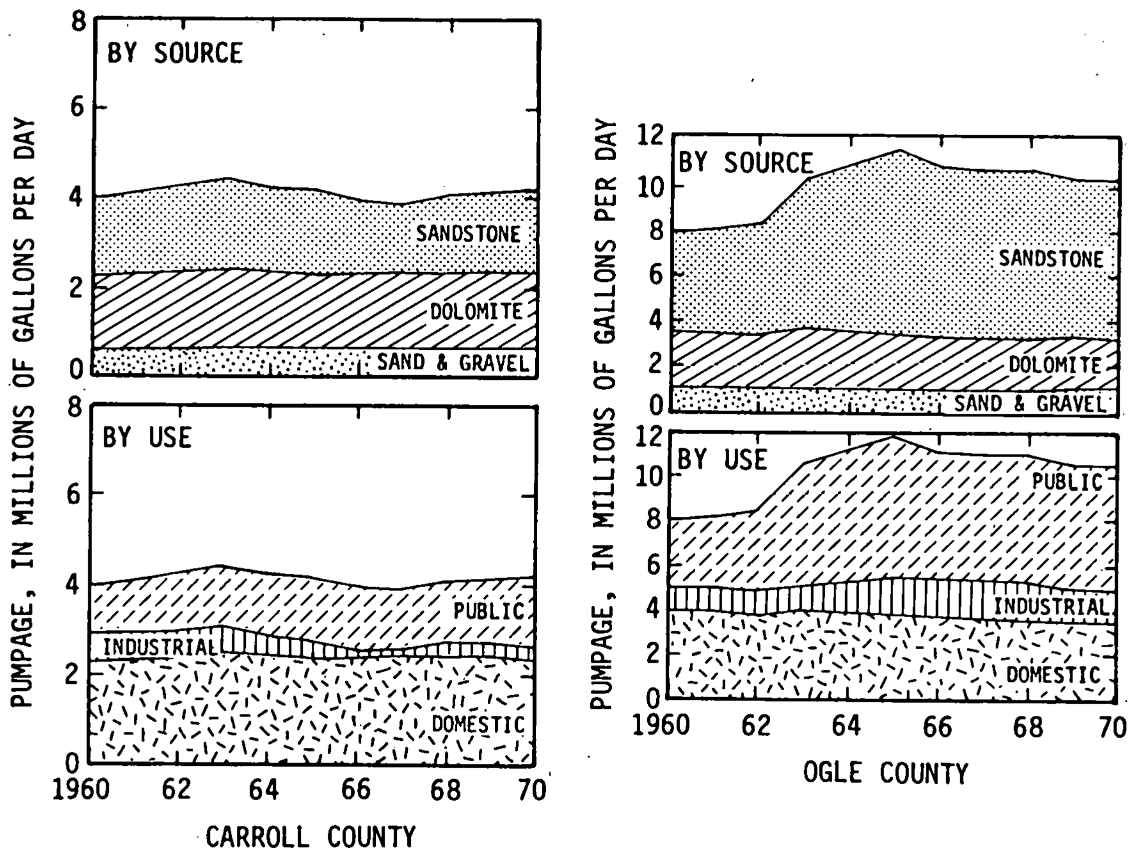

Figure F-5. Total Ground Water Pumpage in Carroll and Ogle Counties, Illinois, 1960-1970 by Source and Use

As stated above, the Ironton-Galesville formation is a principal part of the Cambrian-Ordovician aquifer, for which it comprises 50 percent of the t total coefficient of transmissibility. Of Ogle County, Sasman (Ref. 5) states:

> "More than 99 percent of the public pumpage was for the 10 municipalities with public water supplies. Records indicate there were no subdivisions in the county, and only six institutions that pumped a total of approximately 25,000 gpd in 1960. Rochelle (southeast Ogle County) has much the largest water supply, pumping 69 percent of the public pumpage and 36 percent of the total pumpage in the county."
>
> "Sixteen industries obtained water from their own wells in 1970. The four largest water users pumped between 200,000 and 570,000 gpd each and had a combined pumpage of 1.36 mgd. This volume represented 92 percent of the industrial pumpage. The other industries pumped less than 50,000 gpd each."
>
> "Pumpage for domestic supplies generally decreased throughout the decade, from 3.95 mgd in 1960 to 3.53 mgd in 1970."
>
> In Carroll County, Sasman (Ref. 6) states: "Pumpage increased from 1.10 mgd in 1960 at an average rate of 42,000 gpd per year and was 1.52 mgd in 1970. Pumpage for public supplies accounted for 36 percent of the total ground water pumpage in 1970."
>
> "Industrial pumpage was greatest during the first three years of the decade, averaging 590,000 gpd. Pumpage then declined and reached a minimum of 170,000 gpd in 1967. Industrial pumpage averaged 290,000 gpd in 1970, 50 percent less than in 1960, and was 7 percent of the total pumpage in the county."
>
> "Pumpage for domestic and livestock purposes in Carroll County has increased, but only 4 percent between 1960 and 1970. The 1970 domestic pumpage was 2.30 mgd, or 57 percent of the total pumpage in the county."

In 1970 approximately 68 percent of the Ogle County and 44 percent of the Carroll County total pumpage was obtained from wells completed in sandstone aquifers. No differentiation is made to show what portion is drawn from the Ironton-Galesville formation. Figure F-6 illustrates a portion of the industrial and public water supply wells located in Ogle County, adjacent to the Brookville Area. Table F-3 tabulates these wells as to location, name, depth, and bottom hole formation. Estimated pumpage rates on these wells range from 500 gpd to a high of 370,000 gpd. Of the 14 wells listed, six from

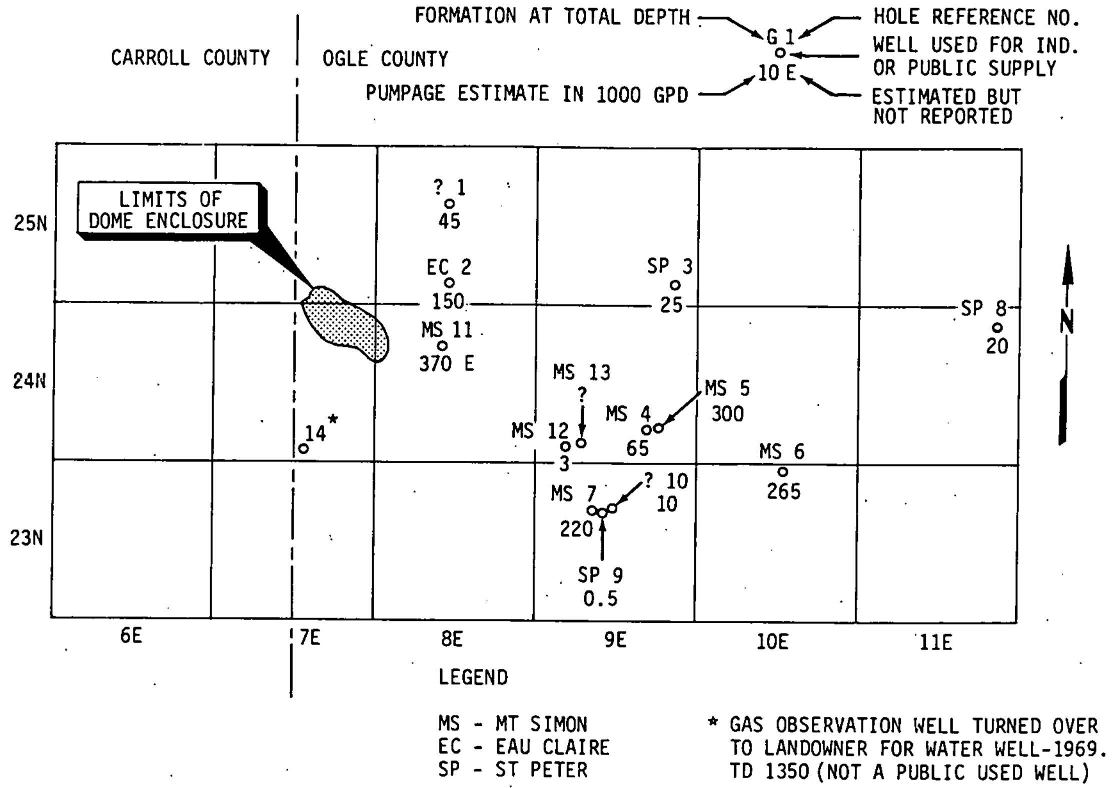

Figure F-6. Location of Industrial and Public Use Wells in Ogle County, Illinois

Table F-3

INDUSTRIAL AND PUBLIC USE WELLS IN OGLE COUNTY, ILLINOIS

LOCATION				NAME OF FIELD	DEPTH/ (ft)	TOTAL DEPTH ELEVATION	TOTAL DEPTH FORMATION
REF.	SEC.	TWP.	RGE.				
1	16	25N	8E	Village of Forreston	300	+620	N.A.
*2	33	25N	8E	Village of Forreston No. 2	1000	-80	Eau Claire
3	36	25N	9E	Village of Leaf River	320	+430	St. Peter
*4	26	24N	9E	Village of Mt. Morris No. 2	1147	-215	Eau Claire
*5	26	24N	9E	Village of Mt. Morris No. 3	1425	-493	Mt. Simon
*6	3	23N	10E	City of Oregon	1200	+528	Mt. Simon
*7	9	23N	8E	City of Polo	2100	-1280	Mt. Simon
8	1	24N	11E	Village of Stillman Valley	300	+425	St. Peter
9	9	23N	9E	White Pines Forest State Park No. 1	300	+440	St. Peter
10	9	23N	9E	White Pines Forest State Park No. 2	450	+390	N.A.
*11	9	23N	8E	Polo City Well	2100	-1264	Mt. Simon
12	27	24N	9E	Mt. Morris City Well	1425	-530	Fon-du-Lac?
13	27	24N	9E	Kable Bros. No. 1	1434	-539	Mt. Simon
14	34	24	7E	C. R. Van De Velde No. 1	1305	-445	N.A.

*Completion includes the Ironton-Galesville formation.

which water is drawn are known to include the Ironton-Galesville formation in their completed intervals.

F.5 POTENTIAL AQUIFER DRAWDOWN PROBLEMS

One possible problem area in the aquifer storage concept is extensive dewatering of formations by drawdown with insufficient recharge. Research done in 1958-1959 by a joint venture of the Illinois State Water and Geological Surveys (Ref. 7) noted the following:

"Computations made, taking into consideration dewatering, indicate that if the distribution of pumpage remains the same as in 1958 and the amount of pumpage from the Cambrian-Ordovician Aquifer increases to a total of 46 mgd and then remains the same, the non-pumping level in Chicago will eventually decline to a position about 100 feet above the top of the Ironton-Galesville Sandstone and at an elevation of about 650 feet below sea level. Pumping levels in wells, if the present rates of pumping from individual wells are maintained, would be within a few feet of the top of the Galena-Plattesville Dolomite, the Glenwood-St. Peter Sandstone, the Prairie du Chien Series, the Trempeleau Dolomite, and the Franconia Formation, and these formations would be dewatered. The dolomites and the Franconia Formation generally are not very permeable, and dewatering of these formations would not appreciably decrease the coefficient of transmissibility of the entire Cambrian-Ordovician Aquifer. However, the Glenwood-St. Peter Sandstone has some permeability. The specific capacities of deep wells would probably decrease on the average about 15 percent as the result of dewatering the St. Peter Sandstone."

"The practical sustained yield of the Cambrian-Ordovician Aquifer is, therefore, estimated to be about 46 mgd. The practical sustained yield of this aquifer will be developed when the total pumpage from deep wells in the Chicago-Joliet-Fox Valley area is about 81 mgd. If pumpage increases at assumed rates the practical sustained yield will be exceeded in about 1965 although equilibrium conditions will not yet have been achieved. The practical sustained yield of the Cambrian-Ordovician Aquifer could be increased by shifting centers of pumping to the west and by spacing wells at greater distances."

Additional research into the matter reported by the Water Survey in 1973 states:

"Estimates in Cooperative Report 1, based on past records of pumpage and water levels, indicated that the practical sustained yield would be exceeded by 1965. However, total pumpage from deep wells in every year since 1958 actually exceeded the withdrawal rate anticipated for 1965. Thus, the practical sustained yield of the aquifer has been exceeded each year since 1958. Sustained pumping at these excessive rates has already resulted in dewatering the St. Peter Sandstone in some parts of the Chicago region and will result in dewatering the Ironton-Galesville Sandstone in many areas much sooner than anticipated in Cooperative Report 1, with a great and continual reduction in yields of wells (Ref. 6).

Despite these bleak warnings, it does not seem probable that such massive dewatering would affect the selected site, because of the presence of the Wisconsin Arch between Chicago and Brookville (see Figures F-1 and F-2). Referring to Figure F-1, it is noted that the Wisconsin Arch lies in central Ogle County and that Chicago is structurally downdip on its relatively steep dipping western flank. Thus, the arch provides isolation of the Brookville structure from any possible drawdown effects of the Chicago ground water region. Further, since the pumped areas are generally thought of as circular in origin, it falls true that as the radius of the pumpage area is increased, the available ground water area and its associated in situ waters likewise increase exponentially. The distance from the Chicago area to the Brookville Dome being approximately 110 miles, it does not seem probable that the drawdown cone effects from the Chicago-Joliet-Fox Valley area would affect the Brookville structure.

F.6 SEISMICITY

Brookville is located at approximately latitude 42° 17' north, longitude 89° 50' west. A search by the National Oceanic and Atmospherics Administration, limited to a 300 km radius around the site, was carried out. Examination of other available records revealed the area to be located in a seismicity 1 region, indicated as an area of minor damage. In the Brookville area, nine earthquakes have been recorded since 1800 (see Table F-4). The intensities of these recorded quakes varied from V to VII. These modified Mercalli intensities are defined as follows:

- V Felt by nearly everyone, many awakened. Some dishes, windows, etc., broken; a few instances of cracked plaster; unstable objects overturned. Disturbances of trees, poles, and other tall objects sometimes noticed. Pendulum clocks may stop.
- VI Felt by all; many frightened and run outdoors. Some heavy furniture moved, a few instances of fallen plaster or damaged chimneys. Damage slight.
- VII Everybody runs outdoors. Damage negligible in buildings of good design and construction, slight to moderate in well-built ordinary structures, considerable in poorly built or badly designed structures; some chimneys broken. Noticed by persons driving motorcars.

Table F-4

EARTHQUAKE DATA FOR BROOKVILLE AREA

YEAR	MONTH	DAY	HOUR	MINUTE	SECOND	LATITUDE	LONGITUDE	MAXIMUM INTENSITY	DISTANCE
1804	08	24	20	10	00.0Z	42.000N	087.800W		141
1905	04	13	16	30	00.0Z	40.400N	091.400W	V	253
1909	05	26	14	42	00.0Z	42.500N	089.000W	VII	55
1909	07	19	04	34	00.0Z	40.200N	090.000W	VII	222
1912	01	02	16	21	00.0Z	41.500N	088.500W	VI	111
1923	11	10	04	00	00.0Z	39.900N	089.900W	V	254
1928	01	23	09	19	00.0Z	42.000N	090.000W		45
1942	03	01	14	43	10.0Z	41.233N	089.733W		105
1972	09	15	05	22	15.7S	41.590N	089.419W	VI	64

F.7 METEOROLOGY AND CLIMATOLOGY

WIND

National Weather Service Records from Joliet Airport and records from Argonne Laboratory Weather Station show an annual wind speed of 8 to 10 mph from the west-southwest direction.

There are no large diurnal effects in wind direction, and wind speeds decrease at the surface during the night. The Great Lakes have very little effect on the wind flow at the site. The topographical flatness of the area surrounding the site eliminates any drainage or channeling effects of the wind.

ATMOSPHERIC DIFFUSION PROPERTIES

Stability conditions measured on a 300 foot meteorclogical tower at Dresden Nuclear Powerplant site show 57 percent neutral stability (Pasquill D), 30 percent unstable (Pasquill A, B, and C), and 13 percent stable (Pasquill E, F, and G).

SEVERE METEOROLOGICAL PHENOMENA

Thunderstorms occur frequently in the site area -- approximately 40 thunderstorm days per year. Hail occurrences vary from one to four per year over the state, with as many as 10 hail days per year reported. High winds in excess of 50 mph have occurred with thunderstorms.

Illinois is in an area of relatively high tornado occurrence. During a 54 year period, 1916 to 1970, six tornadoes have been experienced in Ogle Count; The probability of a tornado occurring at any one point in the area around the site varies between 9.56×10^{-4} and 1.19×10^{-3}, or approximately once in 1000 years.

Severe winter storms with over six inches of snow normally occur every year. Three or more severe storms have occurred in other years. Many of these storms are accompanied by freezing rain.

AMBIENT BACKGROUND CONCENTRATIONS

Background concentrations of SO_2, NO_x, and particulates are typical of a rural area greater than 30 miles downwind of a major industrial metropolitan center. A more detailed investigation of air quality should be considered.

AIR QUALITY ESTIMATION

Ambient pollutant levels may be estimated through the application of atmospheric diffusion models. The estimates are based primarily upon the pollutant emissions, meteorology, and topography as previously described. There are several possible procedures for estimating air quality based on atmospheric dispersion. The complexity and sophistication of these procedures range from a few simple calculations that may be made manually to thousands of calculations that require a computer. The method presented here is the point model, in which the air quality results from a single point source of pollutant within the site boundary.

POINT MODEL

The ambient air quality concentrations that result from the emissions of a single point source have a large degree of variability, depending upon the meteorological conditions. Because of this, the short-term air quality concentrations are of more concern than the long-term. Short-term maximum concentrations are assumed to occur when the plume is trapped in a mixing layer of limited depth. In this case, the 1-hour ground level concentration from a single point source may be estimated from the following equation:

$$X = \frac{Q}{\sqrt{2\pi}\,\sigma_y\, Lu} \left(e^{-0.5 y/\sigma_y^2}\right)$$

where:

X = concentration, g/m

Q = Source emission rate, g/sec

y = standard deviation in the crosswind direction of the plume concentration distribution, meters

L = height of mixing layer, meters

u = wind speed, m/sec

σ_y = distance from the center line of the plume at which the pollutant concentration is one standard deviation less than the pollutant concentration at the center line of the plume

The values of the meteorological parameters are based on the meteorological conditions in the vicinity of the plant. The maximum 24-hour concentration can be estimated by multiplying the estimated one-hour concentration by 0.25. This factor is deemed appropriated for the meteorological conditions to which the above equation applies. The factor implies that the meteorological conditions persist through 6 hours of a 24 hour period. During the remaining 18 hours, wind direction and other meteorological parameters are such that the source has no impact upon the location subjected to contamination during the 6 hour period. The estimated maximum 24 hour concentration may be compared to the maximum 24 hour national standards.

The procedure outlined above is that proposed by the Environmental Protection Agency (Ref. 4). Under certain source and meteorological conditions, the above equation may not be appropriate; other equations (Ref. 8) are available that can be used.

F.8 PROCEDURE FOR SITE EXPLORATION

EVALUATION OF BROOKVILLE STRUCTURE, IRONTON-GALESVILLE AQUIFER

The decision to evaluate the Ironton-Galesville aquifer for air storage was based on the following facts:

1. The Brookville gas storage project of the Natural Gas Pipeline Company of America indicated a structure (location: T-23N and T-24N, R7E, Ogle County, northern Illinois) capable of storing and delivering natural gas in the required amounts. Subsequent drilling and gas injection into the Mt. Simon sandstone showed that the cap rock (Eau Claire formation) was incompetent and that the injected gas migrated upward to the Ironton formation, where it was trapped under the Franconia formation. The project was then abandoned, although the possibility that air or gas could be stored in the Ironton-Galesville aquifer on the same structure cannot be overlooked.

2. The above structure is favorably situated with respect to proposed electric power transmission lines.

3. The top of the Ironton, at 672 feet, indicates that air at 25 to 27 atmospheres could be contained within the Ironton-Galesville aquifer. The original aquifer pressure for the Galesville is given as 248 psia (16.9 atm). Accordingly, it may be possible to deliver air in the range between a maximum pressure of 24 atmospheres (353 psia) and a minimum pressure of 16 atmospheres (235 psia) to an appropriately designed gas turbine.

The following aquifer properties must be determined before an actual air storage facility can be designed:

- <u>Depth of aquifer</u> -- This determines the maximum pressure for air storage. In this particular study, the top of the Ironton at 672 feet is used; this figure was arrived at from driller's logs supplied by the Natural Gas Pipeline Company of America.

- <u>Presence of an impermeable cap rock above the aquifer</u> -- There is conflicting opinion on the competence of the Franconia, which lies immediately over the Ironton, as a tight cap rock. However, when the Mt. Simon formation was tested for gas storage potential in 1964-65, 894 million standard cubic feet of gas was injected. This gas was apparently trapped under the Franconia; having passed successively through the Eau Claire and the Galesville it had been stopped in the Ironton immediately below the Franconia. After abandonment of the gas storage project, the gas was bled off to the atmosphere by a well drilled into the Ironton which was still releasing gas in the summer of 1974. While no estimates were made on the total quantity of gas bled from the Ironton, it appears that the Franconia in this instance served as an adequate cap rock.

- <u>Adequate porosity and permeability for air storage and delivery</u> -- No specific data are available on the porosity and permeability of the Ironton-Galesville aquifer on the Brookville structure. Values for for porosity and permeability have consequently had to be assigned for the Galesville on the basis of known values obtained from cores taken from other structures used for gas storage in northern Illinois. Unfortunately no permeability value can be assigned to the Ironton by this method. It is assumed that the Ironton, while permeable, is less so than the Galesville and that both formations must be treated as a single air storage unit.

- <u>Aquifer formation pressure (must be high enough to contain and deliver the required amount of air)</u> -- Ideally the maximum and minimum air storage pressures in aquifer storage should bracket the original formation pressure. Withdrawal of water from the aquifer will contribute to irregular development of the air bubble and, in time, to the lowering of the original formation pressure. This formation pressure flowering may have already occurred in Galesville area under consideration.

  The Galesville sandstone in the area being discussed is a potable water aquifer and is drawn on by municipalities and industry. It is not known at present if this water withdrawal has been sufficient to invalidate the aquifer for air storage. The average drawdown for deep aquifers in western Ogle County is from 0 to 60 feet. There is no breakdown available for the specific aquifers in the area, and consequently there is no information specifically relating to the Ironton-Galesville formation. However, the original formation pressure for the Galesville reported by Katz

(Ref. 3-25) at 240 psia indicates that a pressure drawdown resulting from a water level drawdown may already have occurred, since the theoretical hydrostatic head at 672 feet depth should be 282 psia.

As indicated by the above discussion, it will be necessary to develop more information than currently exists on the Franconia cap rock and the Ironton and Galesville formations. A small-diameter exploratory (NX) hole is strongly indicated. Cores from this hole should be examined, and permeability and porosity determinations made. A limited amount of information on water injectivity, air injectivity, and formation pressure can also be gained from this hole. If the information gained warrants further study, one of the larger-diameter wells already drilled through the Galesville possibly could be recompleted in the Ironton-Galesville. This well could then be used for obtaining more complete data on air injectivity, storage, and withdrawal. The Oyler No. 1, 2, and 3 wells could be examined for their suitability for extended testing.

SITE EXPLORATION PROGRAM

The following preliminary site exploration program has been formulated:

1. Drill an NX hole through the Franconia and Galesville formations. Core from above the top of the Franconia to below the Galesville. Determine the permeability and porosity for both formations and also the threshold pressure for the Franconia.

2. Set a permanent bridge plug in Oyler No. 2 at the bottom of the Galesville. Perforate the entire Ironton-Galesville at 4 shots per foot. Run a drill stem test and determine the initial closed-in pressure, flow pressure and final closed-in pressure. Measure the aquifer pressure and calculate transmissibility (permeability). Determine the static water level.

3. Select up to three structure test wells from the immediate vicinity of Oyler No. 2. Drill out the cement to the top of the Franconia and recomplete the wells by perforating the Potosi (Basal Trempeleau). These wells may be used as monitors for the pump test that is required to test the competence of the Franconia as a cap rock. If the structure wells were not cased, drill new monitor wells.

4. Run a Reda submersible pump on 2 1/2 inch tubing and set it at the top of the Ironton, above the perforations. Start water withdrawal and monitoring of water levels in the Potosi wells. Pump until satisfied that there is no communication across the Franconia -- 30 days to be adequate.

5. Remove the Reda pump, shut in the well, and measure the pressure buildup in Oyler No. 2 until the pressure stabilizes. Plot the buildup curve.

6. Start compressed air injection in Oyler No. 2. This will require installation of a 700 hp compressor unit and possibly an aftercooler to reduce the air temperature to 150 F ±25 F. The air need not be dehydrated for this initial exploratory phase. The compressor will deliver 3 million std ft^3 of air per day if operated continuously. The air pressure in the formation should not be allowed to exceed 660 x 0.6 = 400 psia for cap rock protection. After injection of a predetermined amount (e.g., 150 x 10^6 scf), the well will be shut in and the pressure allowed to stabilize. Continuous wellhead pressure monitoring will be conducted during this phase. The water level in the monitor holes will be recorded daily.

7. With the quantity of air now in storage, a number of well deliverability tests can be conducted. These drawdown test periods will assist in developing the following formation:

a. Formation permeability to air -- This may be several times larger than the true matrix permeability as determined by core analysis, because of such factors as high-permeability "streaks" within the formation that were not detected by coring and naturally occurring fractures in the formation. For example, Katz (Ref. 3-25) refers to the Galesville sand at the Herscher Dome as having a "measured" permeability, presumably from core analysis, of 467 millidarcys; a permeability to water measured from pumping tests of 1800 millidarcys; and a permeability to gas of 3000 millidarcys. The formation permeability to air, determined by drawdown, is the principal factor governing well size and well spacing.

b. Bubble growth rate -- Some inferences may be drawn from the preliminary test as to the growth rate of the air bubble; it must always be borne in mind that bubble growth will be slower initially with the air-water interface covering a smaller area. The time required for growth of a bubble of adequate air capacity for the anticipated plant size could be the determining factor in the acceptability of a particular aquifer.

c. Cushion air volume -- Air is delivered to the well from the formation by two mechanisms. The first is water influx at the air-water interface; the second is cushion air expansion. The cushion air volume is therefore dependent on the rate of water influx, the minimum bottom hole well pressure required to sustain air delivery to the turbine, and the air volume at that minimum bottom hole pressure.

d. Water efflux and influx rates for the anticipated air injection and withdrawal rates -- The relative ranking of water influx rate and cushion air volume to rate and total volume of delivered air determines the aquifer size required and the volume of cushion air required.

e. Particulate carryover from aquifer -- Driller's logs, core recovery and visual examination of a few core fragments all confirm that the Ironton and Galesville formations are poorly consolidated. There is a strong possibility that, given the airflow rates required, small particles of formation rock may be entrained in the air stream. Unless removed, these particles could damage the wellhead, piping, and turbine blading. If necessary, several remedies are possible, one of which would be to consolidate the sand around the well bore with a permeable plastic. Techniques for consolidating sand under similar circumstances are widely used in oil and gas production. A technique for sand consolidation could be formulated from data acquired in the Oyler No. 2 exploratory hole before proceeding with development drilling.

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Appendix G

BROOKVILLE RESERVOIR DESIGN

G.1 TEMPERATURE AND MOISTURE CONTENT

Because of the hydrophilic character of typical reservoir rocks, capillary forces cause the retention of a portion of the aqueous solutions initially present in the formation when the bulk is displaced by petroleum, natural gas, or air. In the petroleum industry this interstitial aqueous fluid, generally containing dissolved solids, is called "connate water," and its presence significantly affects the performance of a reservoir. Laboratory studies have shown a strong inverse relationship between the fraction of the pore volume retaining water and the permeability of the formation. Instances have been described of a decrease of permeability of the rock to dry air from 2000 millidarcys to 10 millidarcys upon increasing the connate water from 20 percent to 30 percent of the total pore volume (Ref. 1).

Cases are known in the natural gas storage industry -- for example the Herscher field (Ref. 2) -- of actual production of liquid water accompanying the recovery of gas from storage, and it is general practice in the industry to dry the gas before introducing it into a pipeline (Ref. 3). One may, therefore expect that the presence of connate water in an aquifer used for compressed air storage and the change of that water content with time may have a significant effect on the performance of the field. An obvious effect will be that the portion of the interstitial volume occupied by water will be unavailable for air storage. As the interstitial water is removed, or as additional water is introduced by condensation, the effective capacity of the field will change. The removal of the interstitial water by evaporation may significantly improve the deliverability of the field. Addition of liquid water in the vicinity of a well, on the other hand, could greatly reduce the deliverability of the well by decreasing the effective permeability of the formation. Thus the management of water in the aquifer storage field will be an important part of its operation.

The development of a detailed model to describe the dynamic behavior of the temperature and moisture content of the Brookville formation is beyond the scope of the present study. Such a model must take into account the establishment of temperature and moisture gradients from each well bore and the interaction between wells. For the purposes of this study, a greatly simplified description was used to obtain some feeling for the time required to completely remove the interstitial water from the formation and to uniformly heat the formation. A more detailed treatment will be required to describe the actual behavior of such a field.

The temperature change resulting from the injection of 200 F air into a reservoir rock containing air-filled pores and connate water can be estimated from Equation 1:

$$\Delta T_n = \frac{\left(\frac{520}{T_n}\right) F \left[C_P \, \phi \, d_A \, (660-T_n) - W_T \, d_A \, \phi \, h_w\right]}{C_R \, f_R \, d_R + C_w \, f_w \, d_w + (1-F) \, C_p \, \phi \, d_A \left(\frac{520}{T_n}\right)} \qquad (1)$$

where:

T_n = final temperature at the n^{th} charge/discharge cycle

C_p = specific heat of air = 0.24 Btu/lb_m, °R

ϕ = porosity = 0.18

d_A = density of air at 403 psi and 520 R = 2.10 lb/ft^3

C_R = specific heat of quartz = 0.19 Btu/lb, °R

F_R = fraction of volume filled by quartz matrix = 0.78

d_R = density of quartz = 165 lb/ft^3

C_w = specific heat of water = 1.0 Btu/lb, °R

F_w = fraction of volume filled by water = 0.04

d_w = density of water = 62.4 lb/ft^3

h_w = heat of vaporization of water = 970 Btu/lb

F = fraction of air mass cycled = 15-20%

W_T = difference in water content (lb water/lb air) at saturation between air at 403 psi and temperature T and air at 403 psi and 60 F. This can be derived from Reference 4. Values used in these calculations are:

T(°F)	60°	70°	80°	90°	100°	110°	120°	130°	140°	150°	160°
W_T(10^{-4} lb/lb air)	-	1.6	4.2	7.4	12	17	23	36	47	60	73

Equation 1 is based on a heat balance between the incoming air at 200 F, the outgoing air at temperature T_n, the water and rock in the reservoir at temperature T_n (assumed to be uniformly heated), and the heat required to saturate the out-going air. ΔT_n is the difference in temperature of the rock and water in the reservoir between the nth injection and the nth removal of air. Because the concentration of water vapor in the outgoing air increases rapidly with increasing temperature, ΔT_n is a function of T_n. An iterative approximation was employed to estimate δT_n. The change in effective porosity from the initial value, 18 percent, to the final (dry) value of 22 percent was neglected in making these estimates.

In Equation 1, the first term in the numerator represents the heat given up in cooling the injected air from 200 F to the final temperature; the second term is the heat taken up in evaporating water in the formation to saturate the incoming air. A "stabilized" condition arises when these two terms are equal. From Equation 2 the stabilization temperature can be calculated:

$$0.0911\ (660-T_n) = 367\ W_T \tag{2}$$

The terms in the denominator represent the heat taken up respectively by the rock matrix (assumed to be quartz), by the connate water, and by the uncycled air in the reservoir. The first term represents approximately 90 percent of the total.

To calculate the number of cycles to reach a given temperature, Equation 1 was used to calculate ΔT/cycle at 10 degree intervals, and an average value of ΔT/cycle over each interval was used to calculate the number of cycles needed to increase the temperature over that interval. Thus, while only 114 cycles were calculated as needed to go from 60 to 70 F, 256 cycles would be needed to go from 110 to 120 F.

To calculate the number of cycles needed to dehydrate the formation at the stabilized condition, the appropriate W_T was used in Equation 3 to calculate the mass of water per ft^3 of formation removed in each cycle:

$$\text{Water removed (lb/ft}^3\text{/cycle)} = W_T\ \phi\ d_A\ F\left(\frac{520}{T_n}\right) \tag{3}$$

Thus, at the 125 F stabilized condition, each cycle would remove 1.17×10^{-4} pounds of water per ft^3 formation at 12 percent cycling. Since initially the formation contained 2.5 pounds of water per ft^3 of formation, 21,400 cycles would be required to remove the connate water.

G.2 WATER MOVEMENT IN THE RESERVOIR

To estimate the rate at which water moves through the reservoir, the equations first developed by Van Everdingen and Hurst to describe water inflow into a producing petroleum reservoir have been employed. These are solutions to the diffusivity equation expressing the relation between pressure, radius, and time for a radial system where the driving, or resisting, potential is the water and rock compressibility (Equation 4):

$$\frac{\partial^2 P}{\partial r^2} + \frac{1}{r}\frac{\partial P}{\partial r} = \frac{\mu \phi C}{k}\frac{\partial P}{\partial t} \tag{4}$$

P, r, and t are pressure, radius, and time; and k, μ, ϕ, and C are respectively the permeability, fluid viscosity, porosity, and compressibility of the reservoir. The Van Everdingen and Hurst expressions are given by Equations 5, 6, and 7:

$$W = B\left(\sum_{0}^{t} \Delta P_t\right) Q(t) \tag{5}$$

$$t_D = 6.323 \times 10^{-3} \frac{kt}{\phi \mu C r^2} \tag{6}$$

$$B = 6.68 \phi C r^2 h \tag{7}$$

The water influx or efflux (W) is expressed in ft^3/day when the overpressure (Δ P) is expressed in psia, the time (t) in days, and the radius (r) and formation thickness (h) are expressed in feet. The quantity Q(t), a dimensionless water influx, can be obtained from tables (Refs. 5, 6, and 7) as a function of a dimensionless time t_D.

To apply Equation 6, the permeability must be expressed in millidarcys and the viscosity in centipoise. This expression has been widely used in petroleum reservoir engineering (Ref. 7), and in the design of natural gas storage fields (Ref. 3) and compressed air storage fields (Ref. 8). It applies strictly to circular reservoirs surrounded by horizontal aquifers of constant thickness, porosity, permeability, and compressibility. Correction can be made for the case in which the surrounding aquifer is of finite extent. The Brookville structure is large enough to justify the infinite aquifer approximation. Because the deviations from circularity and flatness are sufficiently small in the Brookville case, application of these equations appears appropriate to this design study. Uniformity of thickness, permeability, porosity, and compressibility have been assumed.

For the Brookville structure, the following values were used:

ϕ = 0.18

μ = 1.11 centipoise

C = 8×10^{-6}

Formation pressure = 240 psia

h = 134 ft

K = 500 millidarcys

Resulting in:

$$B = 1.289 \times 10^{-3} r^2$$

$$t_D = 1.978 \times 10^6 \frac{t}{r^2}$$

To estimate the extent that water inflow from the aquifer drives the air during the daily cycle, the volume influx of water can be calculated from Equation 5 for t = 1 day and various radii. The maximum driving force for water inflow is the difference between the formation pressure 240 psia and the bottom hole pressure corresponding to a regenerator inlet pressure of 173 psia. Allowing for losses in the manifold and wells of 5 psia, the maximum average ΔP over the generation time is 31 psia. The daily fractional volume change must then be less than the following:

r (ft)	t_D	Q(t)	B (ft^3/psia)	ΔV (ft^3/day)	$\Delta V/V$ (%)
100	198.00	74.69	12.85	30,240	3.89%
500	7.92	6.27	321.2	62,410	0.34%
1000	1.98	2.43	1285.0	96,800	0.13%
2500	0.317	0.782	8031.0	197,800	0.04%
5000	0.0792	0.352	32125.0	350,500	0.02%

Since at the pressure levels of the Brookville site there are reservoirs of greater than 1000 feet radius for the 150 MW, 10 hour plant, it can be seen that the water drive during charging and discharging will be small and that, to a good approximation, the design can be based on the cycling of air mass into and out of a fixed volume. The consequence of neglecting the daily motion of the water front in the equilibrium plant (one in which the average weekly pressure is 240 psi) will be that the actual variations in pressure during charging and discharging will be somewhat less than those on which the plant design is based.

The rate of water movement in the aquifer controls the rate at which the reservoir volume can be developed. The maximum rate of development can be achieved by using a constant overpressure equal to the threshold pressure of the cap rock. At a gradient of 0.6 psia/ft depth, this amounts to 403 - 240 = 163 psia. For the well spacing of 391 feet determined by the requirements of the equilibrium plant design, coalescence of the air reservoirs from individual wells will occur at a reservoir radius of 195 feet. Up to the time of coalescence, the rate of water movement can be calculated from Equation 5. The results for volume of water displaced and radial growth rate as a function of reservoir radius are plotted in Figures G-1 and G-2. The radial growth rate was calculated from Equation 8:

$$\mathring{r} = \sqrt{r^2 + \frac{W}{\pi h \phi}} \tag{8}$$

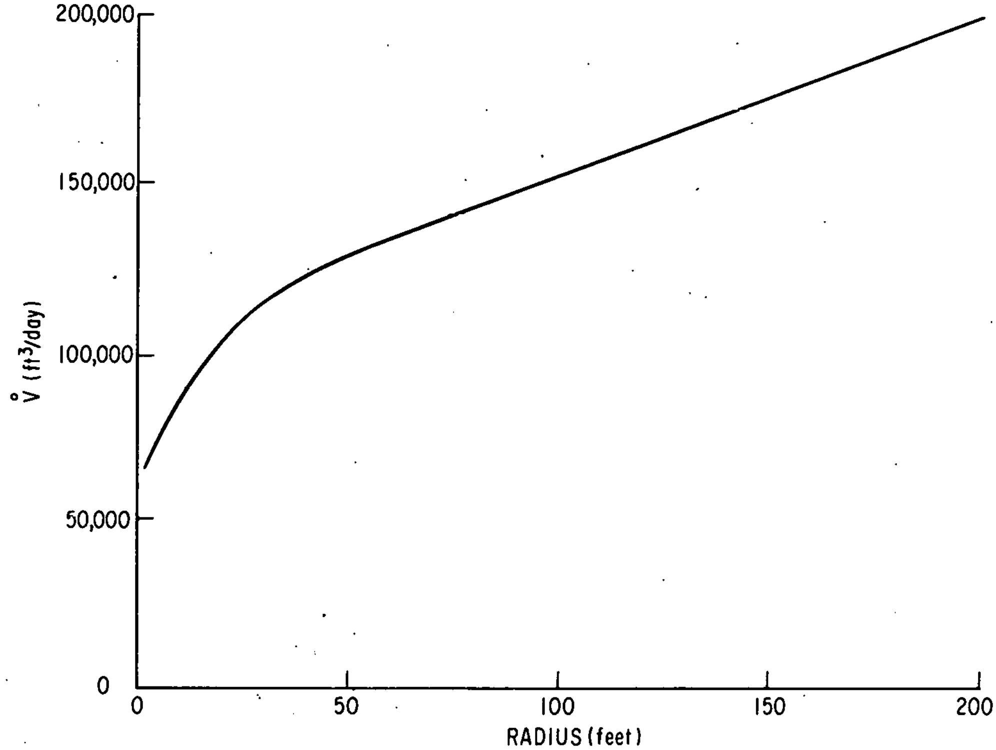

Figure G-1. Volumetric Displacement of Water as a Function of Radius for a Single Well in the Brookville Aquifer for Δ P = 163 Psia

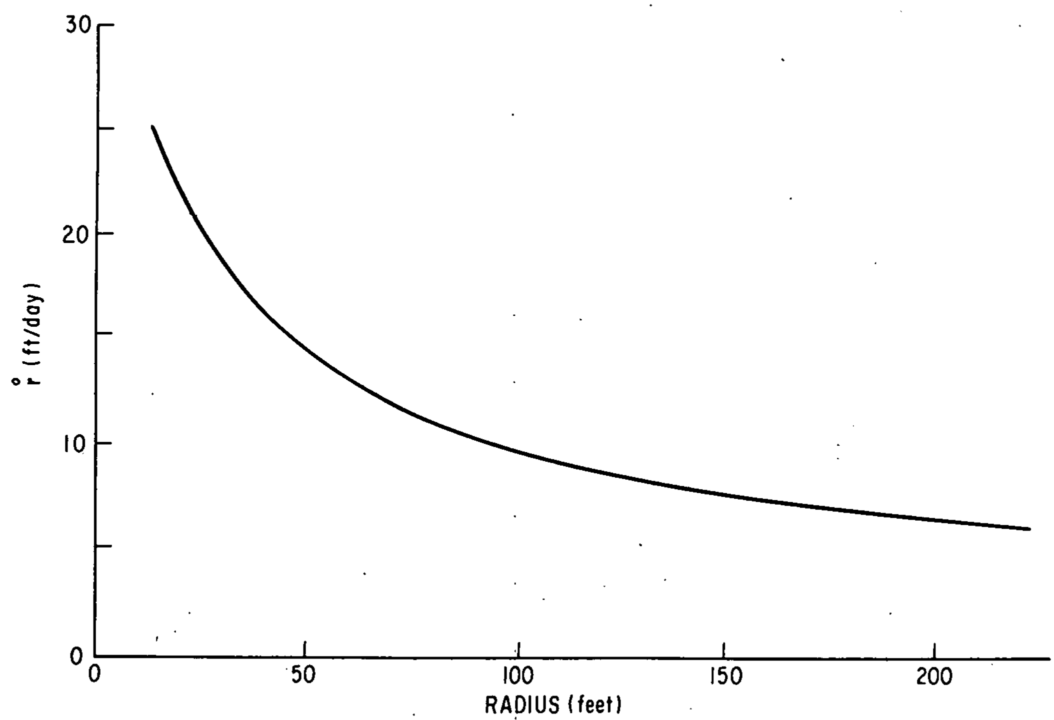

Figure G-2. Radial Rate of Reservoir Growth as a Function of Radius in the Brookville Aquifer for P = 163 Psia

Average values of $\mathring{r}$ over intervals were used to calculate the time required (20 days) to reach a 195 foot radius. Since the rate of movement may be a factor of 2 to 4 higher than that calculated (Ref. 3), this time may be considered to be an upper limit to the time required.

During the coalescence of the reservoirs from the individual wells, the water movement in the reservoir will be complex, and it is possible that water will not be displaced completely from sections of the reservoir. After coalescence of the reservoirs from the initial 28 wells have occurred, the rate of water movement calculated from Equation 5 is 10 percent of the flow of the 28 individual wells at the time of coalescence. Thus, during the formation of the last 27 percent of the reservoir there will be a rapid decline in the rate of delivery of air by the compressor. If the average rate of reservoir growth during this phase is 10 percent of the growth rate at the time of initial contact, an additional 48 days will be required to complete the 150 MW, 403 psia reservoir.

One method for developing the reservoir to its full design volume is to start cycling the initial 150 MW plant, operating at an upper pressure limit of 403 psia and allowing the reservoir to grow by extending the charging time each day to fill the void volume created by the efflux of water. The average bottom hole pressure for this cycle will be 350 psia. To calculate the rate of water front movement, it is necessary to compute the pressure drop in the formation at the full charging flow rate, by the procedure described below under "Calculations of Flow Losses." The ΔP at the water front will decline from 64 to 45 psia as the reservoir radius increases from 12,000 to 4,000 feet.

If the average pressure at the sand face remains constant at 350 psia, the estimated time needed to accomplish the development of the full reservoir by this method would be 10 years. However, if a constant mass of air is cycled from the reservoir as it enlarges, the average pressure at the sand face will increase during the expansion of the reservoir. As a consequence, the time required to produce the equilibrium volume would be reduced to about 5 years.

G.3 CALCULATIONS OF FLOW LOSSES

FLOW LOSSES IN HORIZONTAL PIPES

Flow losses in the surface air collection system were calculated from the Weymouth expression (Ref. 9), Equation 9:

$$P_2^2 = P_1^2 - 2.493 \times 10^{-6} \frac{Q^2 T \ell f z}{d^5} \tag{9}$$

P_1 and P_2 are the initial and final pressures in psia. The airflow Q is expressed in lbs/hr, the absolute temperature T in °R, the pipe length ℓ in feet, and the pipe inside diameter d in inches. Over the pressure range appropriate to the Brookville site, the compressibility of air, z, can be taken as 1.0. The friction factor f used is a function of pipe inside diameter (Ref. 9):

I. D.	f
5.50	0.0125
7.00	0.0120
8.63	0.0115
10.75	0.0110
13.38	0.0105
16.00	0.0100
20.00	0.0095

STATIC PRESSURE IN WELLS

To calculate the increase in pressure at the bottom of the well due to height of the air column in the well, Equation 10 was used (Ref. 9):

$$P_2 = P_1 \, e^{0.01877 \, \ell/Tz} \tag{10}$$

The shut-in bottom hole pressure P_2 and the static wellhead pressure P_1 are expressed in psia. The depth of the well ℓ is expressed in feet and the absolute temperature T in °R. At the pressures encountered in the Brookville site, the compressibility of air is taken as 1.

FLOWING PRESSURE DROP IN WELLS

Equation 11 was used to calculate the pressure at the bottom hole P_2 corresponding to a pressure P_1 at the wellhead during charging of the reservoir with air (Ref. 9):

$$P_2^2 = P_1^2\left(e^{0.0375 \, \ell T/z}\right) - 6.56 \times 10^{-5}\left(\frac{Q^2T^2z^2f}{d^5}\right)\left(e^{0.0375 \, \ell/Tz} - 1\right) \tag{11}$$

where the symbols refer to the same quantities and units used in Equations 9 and 10. To calculate the pressure at the wellhead (P_1) due to a pressure (P_2) at the bottom hole during discharging of the reservoir, Equation 12 was employed:

$$P_2^2 = P_1^2\left(e^{-0.0375 \, \ell/Tz}\right) - 6.56 \times 10^{5}\left(\frac{Q^2T^2z^2f}{d^5}\right)\left(1 - e^{-0.0375 \, \ell/Tz}\right) \tag{12}$$

FLOWING PRESSURE DROP IN THE FORMATION

Equation 13 was employed to calculate the pressure drop in the formation, for a distance r_c into the formation to a well bore of radius r_w, during production of air[2]:

$$P_w^{\,2} = P_f^{\,2} - \frac{447 Tz\mu Q}{kh} \ln \frac{r_f}{r_w} - \frac{3.11 \times 10^{-13}\, \beta T Q^2}{h^2} \left(\frac{1}{r_w} - \frac{1}{r_f} \right) \tag{13}$$

In addition to the quantities already defined in this appendix, the permeability k is expressed in millidarcys and the formation thickness h in feet. The turbulence factor β is a function of the formation permeability. For these calculations a value of 1.27×10^7 was used for β. To calculate the pressure drop in the formation at a distance r_f from a well bore of radius r_w during the injection of air, Equation 14 was used:

$$P_f^{\,2} = P_w^{\,2} - \frac{447 Tz\mu Q}{kh} \ln \frac{r_f}{r_w} - \frac{3.11 \times 10^{-3}\, \beta T Q^2}{h^2} \left(\frac{1}{r_w} - \frac{1}{r_f} \right) \tag{14}$$

CORRECTED RESERVOIR CAPACITY

During the injection of air, a pressure gradient will be built up between the bottom hole and the water face. The shape of the pressure gradient can be calculated from Equation 13. During the shut-in period between pumping and generation, this gradient should equalize so that the average reservoir pressure will be intermediate between the bottom hole and water face flowing pressures. It is the static average pressure that will determine the mass of air stored by the reservoir (Equation 15):

$$M = 2\pi h \phi \int_{r_w}^{r_f} \rho(r) r\,dr \tag{15}$$

where $$p(r) = \frac{\rho o}{14.7} P(r) \tag{16}$$

ρ_o = density at the reservoir temperature and 1 atmosphere P(r) = function relating pressure to radius

The function P(r) may be approximated by Equation 17, obtained by taking the first two terms on the right-hand side of Equation 15:

$$P^2(r) = P_f^{\,2} \cong P_w^{\,2} - \frac{447\, Tz\mu Q}{kh} \ln \frac{r}{r_w} \tag{17}$$

Substituting Equations 16 and 17 into Equation 15 results in Equation 18:

$$M = \frac{2\pi h \phi \rho_o}{14.7} \int_{r_w}^{r_f} \left(P_w^{\,2} - \frac{447\ Tz\mu Q}{kh} \ln \frac{r}{r_w}\right)^{1/2} rdr \qquad (18)$$

When the pressure drop in the formation is small compared to P_W, an analytical expression for Equation 18 can be readily obtained. In the present study, since the pressure drops between well bore and water face were often large, graphical integration was employed to obtain the corrected mass in the reservoir at the end of the charge and discharge cycles.

G.4 PRESSURE VARIATIONS DURING WEEKLY CYCLE

For a constant volume reservoir, the instantaneous pressure in the formation can be expressed by Equation 19 as a function of the maximum formation pressure, attained when the reservoir is fully charged:

$$P_i = P_m \left(\frac{M_i}{M_m}\right) \qquad (19)$$

M_i and M_m represent the instantaneous mass and maximum mass of air stored in the reservoir. From the design capacity and the charge/discharge cycle, the hourly inventory of air in the reservoir can be calculated. Table G-1 summarizes the results for reservoirs in which 5, 10, 20, and 30 percent of the maximum stored air mass cycled during the week, and Figure G-3 displays the pressure variation for the case in which 30 percent of the air mass is cycled.

To specify this cycle, several assumptions were made about the duty cycle:

1. That the daily idle time is divided equally between the charge/discharge and discharge/charge changeover periods.

2. That there is no recharging of the reservoir on Friday evening.

3. That the weekend pumping is divided equally between Saturday and Sunday.

4. That the rate at which mass is removed from or returned to the air reservoir is linear with time.

The average pressure during the cycle was calculated by summing the produc[illegible] of time (hours) and pressure (psia) for each increment of the cycle, and divi[illegible]ing the total by 168 hours. The results for the four cases in Table G-1 are

Table G-1

INVENTORY OF AIR STORED IN THE RESERVOIR DURING THE WEEKLY CYCLE

		Air Mass (10^6 lb)				Pressure (% of max.)			
End of Mode	Day	% Mass Cycled: 5	10	20	30	5	10	20	30
Charge	Sun.	3194	1597	799	532	100.0	100.0	100.0	100.0
Discharge	Mon.	3110	1512	714	447	97.3	94.7	89.4	84.0
Charge	Mon.	3176	1579	780	514	99.4	98.9	97.7	96.5
Discharge	Tues.	3091	1494	695	429	96.7	93.5	87.0	80.6
Charge	Tues.	3157	1560	761	495	98.8	97.7	95.3	93.0
Discharge	Wed.	3072	1475	676	410	96.2	92.3	84.6	77.0
Charge	Wed.	3138	1541	743	476	98.2	96.5	93.0	89.4
Discharge	Thurs.	3053	1456	658	391	95.6	91.2	82.4	73.4
Charge	Thurs.	3120	1522	724	458	97.7	95.3	90.7	86.0
Discharge	Fri.	3035	1438	639	373	95.0	90.0	80.0	70.0
Charge	Fri.	3035	1438	639	373	95.0	90.0	80.0	70.0
Charge	Sat.	3115	1517	719	453	97.5	95.0	90.0	85.0
Charge	Sun.	3194	1597	799	532	100.0	100.0	100.0	100.0
Average		3110.8	1513.6	715.0	448.8	97.4	94.8	89.5	84.3
Reservoir radius at 125°F (ft)		6166	4360	3083	2517				

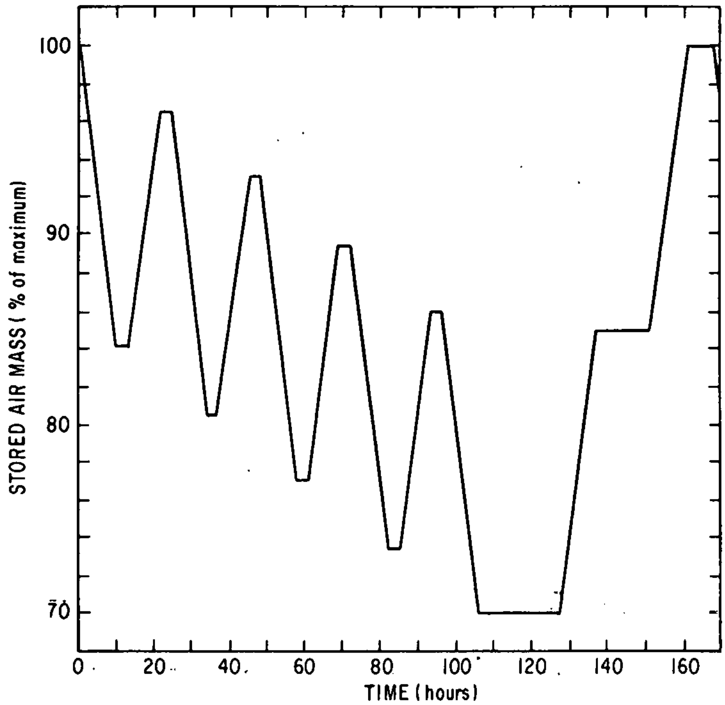

Figure G-3. Air Inventory During Weekly Cycle for 30 Percent Cycling

summarized in Table G-2.* From the condition for reservoir size stability, that the average pressure be equal to the discovery pressure (240 psia), the maximum and minimum pressures in Table G-2 during the cycle were calculated. The minimum formation pressures determined in this way were used to calculate the number of wells needed for each case, as described in the main text.

Table G-2

MAXIMUM AND MINIMUM RESERVOIR PRESSURES

Pressure	Percent Mass Cycled			
	5	10	20	30
Average pressure (% of maximum pressure)	97.4	94.8	89.5	84.4
Maximum pressure (psi)	246.0	253.0	268.0	285.0
Minimum pressure (psi)	234.0	228.0	215.0	199.0

*If the actual duty cycle were different from that assumed, then the actual average formation pressure would change. For example, for the case in which 30 percent of the air mass is cycled, if all of the idle time were spent at the daily maximum pressure, then the average pressure would be 87.1 percent of the weekly maximum, whereas were all the idle time spent at the lower daily pressure, then the average pressure would be 81.5 percent of the weekly maximum. During the actual operation of a plant it will be necessary to maintain a time-pressure record and make small adjustments in the operating schedule to maintain a constant reservoir size.

G.5 ALTERNATIVES FOR DEVELOPMENT TO THE EQUILIBRIUM DESIGNS

A number of technically feasible alternatives for developing the Brookville site to a 600 MW, 10 hour generation, CAES plant are conceptually possible. They may be divided into development of the full air reservoir initially, followed by incremental development of generating capacity, and those that develop the air reservoir in increments matched to the generating capacity additions.

If the field is developed to a full size and capacity brought on in increments, this might be done either by putting in 77 wells spaced at 391 feet, and repeating this process by extending the producing part of the air field, or by spacing wells more widely to cover the whole air reservoir in the beginning and then drilling additional wells between the initial ones to allow more intensive cycling of the stored air. An analysis of the latter approach indicated that the reduced pumping power costs that would be obtained in the initial 150 MW plant would not offset the increased capital charges due to the extensive initial air collection system required. Thus if the option of full reservoir development were chosen, incremental addition of the wells and air collection system would be selected.

In addition to the choice between full initial development of the reservoir and incremental development, the developer has the option of employing the equilibrium pressure in the formation or, during the development period, a higher pressure limited by the safe threshold pressure of the cap rock. Thus, four alternatives were considered, based on the combinations of these choices:

1. Full reservoir development at 403* psia followed by pressure reduction and operation at 284* psia.

2. Incremental reservoir development at 403 psia followed by pressure reduction and operation at 284 psia.

3. Full reservoir development and operation at 403 psia until the reservoir reaches the equilibrium radius, followed by pressure reduction and operation at 284 psia.

4. Incremental reservoir development and operation at 403 psia until the total air reservoir reaches the equilibrium radius, followed by pressure reduction and operation at 284 psia.

The first and second alternatives require a special development plant equipped with a chiller/heater/dehydrator. A central compressor pumping air through the manifold system ultimately to be used for operation of the generation station can be used as the special development plant. The piping

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*Maximum operating pressures in the formation.

used in this manifold must be capable of withstanding 420 psia, rather than the 290 psia required by the piping in the equilibrium plant, but it may be sized to accept smaller flows than the final plant manifold. A high degree of confidence in the uniformity of the formation characteristics and cap rock integrity would be needed because of the large initial investment in wells, air piping, and compressor plant required for the development of the field with a central compressor. An alternative to the use of a central plant is to employ individual compressor units, each equipped with a chiller/heater/dehydrator. For development of a 150 MW reservoir in 3 to 6 months, purchase or rental of 77 such units would be required. Since the air in the reservoir would be very nearly at its initial temperature when cycling begins, a dehydrator would be needed on each 150 MW module.

The second and third alternatives require that each 150 MW plant be equipped with a compressor capable of delivering 420 psia, and the air distribution piping must be designed to withstand this pressure. The advantage of reduced manifold costs associated with development of the field with individual compressor units is no longer present, and development of the field using the compressor train to be employed in the operating plant is favored. After the reservoir has been developed to its full size and the pressure let down to 284 psia, the booster compressors will have to be reworked to remove the final compression stage. The result in the final plants will be that the motor driving the booster train, which was sized for the 420 psia booster, will be somewhat oversized for its task. Conceptually, there are two ways that the second and fourth alternatives might be accomplished. If stability in the reservoir location is to be maintained, then the expansion of the reservoir will have to be accomplished radially from the peak of the dome. As a consequence, either the air collection system will have to be reworked extensively at each expansion of generation capacity, or the initial air collection system must be designed with larger pipe diameters than are required in the equilibrium plant.

If the requirement for stability of the reservoir location is relaxed, then the development of incremental plants may be carried out at the site where they are needed in the equilibrium plant. No additional costs for the air collection system would be incurred in this case. There may be justification for relaxing the stability requirement for the interim plants, since long-term stability of the air reservoir location is not required. The radius of curvature of the Brookville Dome is sufficiently great that the driving force for moving a reservoir up the flank of the dome to the crest should be small.

A number of other approaches to the development of the air reservoir might be considered. If the maximum rate of development were not required, then some economies could be achieved by development at a formation pressure less than 403 psia. The time required to develop the reservoir will increase as the reciprocal of the difference between the development pressure and 240 psia. In the event that a slower development time is suited to the utility's requirements, then a tradeoff between development compressor flow rate capabilities, energy costs for reservoir development, and cost of the investment in wells and air distribution system should be performed.

The critical information needed for this tradeoff analysis is the relationship of the timing of the utility's requirement for additional generating capacity to the rate at which the air reservoir can be developed. To develop this relationship requires a detailed analysis of the utility demand growth and generation expansion characteristics on the one hand, and of the water flow characteristics in the Brookville Dome on the other. The carrying out of these analyses, which is beyond the scope of the present study, would be required before an optimized development plan for the reservoir could be prepared.

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G-10. Reference G-3, Chapter 10.

Account No.	Item	Description
102.7	Railway	Approximately 3 1/2 mile connection to nearest railroad spurs of Illinois Central or Chicago Burlington and Quincy Stations.

H.2 STRUCTURES AND IMPROVEMENTS

ACCOUNT 111. YARD WORK

Account No.	Equipment	Description
111.14	Fencing and gates	
111.141	Plant	4800 foot fencing per two plant cluster; two 50 foot gates.
111.142	Manifold	
111.1421	Initial plant (29 wells)	44,000 foot fencing; two 50 foot gates.
111.1422	Four plants (77 wells each)	143,000 foot fencing; four 50 foot gates.
111.15	Sewage treatment system	One aerobic digestion process sewage treatment plant including comminutor, dual blowers and aerobic digester having a capacity of 500 gallons per day.
111.16	Yard drainage	Crushed stone footing between equipment forms. Allows adequate water drainage to subsurface water table).
111.17	Yard lighting	
111.171	Building exterior	Minimum of 5 foot-candles intensity.
111.172	Tanker unloading area	Mercury vapor floodlights average of 20 foot-candles intensity.
111.173	Perimeter fencing	Mercury vapor lamps at 150 foot intervals. Average of 1/2 foot-candle intensity with 5 foot-candles along roads and walkways.

Appendix H

BROOKVILLE STATION EQUIPMENT LIST

H.1 LAND AND RIGHTS

ACCOUNT 101. LAND AND LAND PRIVILEGE ACQUISITION

These accounts do not include any equipment. However, the final plant design and economic analysis must consider the following:

Account No.	Item	Description
101. 1	Land and savings	Approximately 1200 acres
101. 11	Survey of underground formation	25 to 50 structural wells.
101. 2	Easements and right-of-ways	
101. 3	Clearing of land and demolition of structure	Approximately 20 acres, for surface plant only.

ACCOUNT 102. RELOCATION OF BUILDINGS, UTILITIES, ROADS

Account No.	Item	Description
102. 1	Buildings	No permanent structures on site of aquifer or surface plants.
102. 2	Telephones	Nearest telephone lines are 3/10 mile from site.
102. 3	Power lines	Nearest power lines are 4-1/2 miles from site.
102. 3	Water pipes and conduit	Conduit laid to transmit treated sewage effluent and water removed from air to Elkhorn Creek, approximately 1 3/4 miles from site.
102. 4	Sanitary and storm sewers	None required.
102. 5	Gas pipes	None required.
102. 6	Highways	Approximately one mile of highway necessary to support 50 ton line load, to connect plant to Illinois Route 52.

Account No.	Equipment	Description
111.18	Railroad	
111.181	Two-plant cluster	200 foot standard gage railroad track and bedding per two-plant clusters.
111.182	Manifold perimeter to each plant cluster entrance	11,500 foot standard gage railroad track and bedding.
111.19	City water	Plant uses water from aquifer formation for all water requirements.
111.20	Yard fire protection system	Two-way hydrants are spaced at 250 foot intervals along the entire length of a yard fire main that encircles the plant. Hose house with 250 foot by 2 1/2 inch hose at each main. Main is steel. Supplied from a 130,000 gallon elevated tank by the 750 gpm pumps and a 25 gpm pump.
111.21	Switchyard area grading and surface	Crushed stone surface similar to plant.

ACCOUNT 112. CONTROL BUILDING

Account No.	Equipment	Description
112.11	Substructure work	Reinforced concrete column footing.
112.12	Superstructure work	210 ft x 135 ft x 20 ft high. Insulated metal siding exterior walls, insulated metal, bullet proof. Concrete slab floor.
112.2	Building services	
112.21	Plumbing and drainage system	Worker's sanitary and lunch-room facility piping. Storm drainage from building roof conveyed to.
112.22	Heating, ventilation and air conditioning system	
112.222	Unit heaters	Steam unit heaters with fans.
112.2231	Roof ventilators	Ventilators with fans.

Account No.	Equipment	Description
112.22231	Exhaust fans	
112.2224	Air-conditioning	50 tons of air-conditioning including supply and return ductwork, controls, and supplemental baseboard heat for personnel areas.
111.23	Fire protection	Cable room, relay room, and cable tray runs provided with closed head CO_2 sprinkler system. Control building has automatic water spray sprinkler system.
112.24	Lighting protection and service wiring	Standard fixtures that comply with standard building and OSHA codes.

H.3 PUMPED AIR STORAGE SYSTEM

ACCOUNT 121. AQUIFER

Account No.	Equipment	Description
121.1	Well drilling	77 holes, 9 1/2 inches in diameter, on a 391 foot spacing, per 150 MW_e module. Hole depth varies from 120 feet to 180 feet below surface.
121.2	Well casings	API grade steel casing, N-80, 6.184 ID, 29.00 lb/ft.
121.3	Compressor	Compressors required to displace water, prior to use of main axial compressor.

ACCOUNT 122. COMPRESSED AIR PIPING

Account No.	Equipment	Description
122.1	Manifold	
122.11	Initial plant (29 wells)	
122.111	Piping	Approximately 900,000 pounds of carbon steel pipe, 35,000 psi minimum tensile yield strength, 420 psi operating pressure.

Account No.	Equipment	Description
122.112	Valves	29 -- 10 inch hand operated gate valves (one valve at each well head).
122.113	Fittings	As required.
122.1131	Elbow	Fabricated.
122.1132	Tee	Fabricated.
122.1133	Cross	Fabricated.
122.1134	Reducers	Forged - as required.
122.1135	Instrument fittings	29 - 2 inch pipe nozzles, to accept pitot tube flow necessary probe for flow balancing operation only.
122.114	Hangers and supports	As required, to allow expansion of pipe and to cause minimal induced stress in pipe. Can be specified only after final design of manifold.
122.115	Miscellaneous material	As required.
122.1151	Paint	Paint to apply one coat to entire manifold.
122.1152	Insulation	None required.
122.1153	Cathodic protection system	None required.
122.12	Four final plants (77 wells each)	
122.121	Piping	Approximately 1,000,000 pounds of carbon steel pipe, 35,000 psi minimum tensile yield strength, 300 psi operating pressure each manifold.
122.122	Valves	77 - 6 inch hand operated gate valves, one at each well head.
122.123	Fittings	As required.
122.1231	Elbow	Fabricated.
122.1232	Tee	Fabricated.
122.1233	Cross	Fabricated.

Account No.	Equipment	Description
122.1234	Reducers	Reducers as required.
122.1235	Instrument fittings	77 - 2 inch pipe nozzles, to accept pitot tube flow necessary probe, for flow balancing operation.
122.124	Hangers and supports	As required, to allow expansion of pipe and to cause minimal induced stress in pipe. Can be specified only after final design of manifold.
122.125	Miscellaneous material	
122.1251	Paint	Paint to apply one coat to entire manifold.
122.1252	Insulation	None required.
122.1253	Cathodic protection system	None required.
122.1254	Blind flanges	To allow expansion of initial 29 well manifold to 77 well manifold.
122.12541	Main feeder line	1 - 48 inch end cap 420 psi working pressure.
122.12542	Branches	7 - 18 inch blind flanges 420 psi working pressure. 1 - 20 inch blind flange 420 psi working pressure.
122.1255	Spool piece	1 - 48 inch spool, 600 feet long. Piece is used for other parts of manifold requiring 48 inch pipe.
122.131	Manifold burial requirements	77 well manifolds only.
122.1311	Piping	No change from item 122.121.
122.132	Valves	77 - 6 inch hand operated gate valves, with 6 foot extension stem, one at each well head replacing item 122.122.
122.133	Fittings	No change from items 122.1231 to 122.1234.

Account No.	Equipment	Description
122.1335	Instrument fittings	77 - flow transducers, with connections terminating at above-ground weatherproof box. Replacing item 122.1235.
122.134	Hangers and supports	As required to allow expansion of pipe underground, to cause minimal induced stress. Can be specified only after final design.
122.135	Miscellaneous materials	No change from items 122.1251 and 122.1252 above.
122.1353	Cathodic protection system	System necessary to protect pipe from underground galvanic corrosion.
122.2	Surface plant	
122.21	Initial plant (29 wells)	
122.211	Piping	Approximately 90,000 pounds of 36 inch steel pipe connecting various surface plant hardware components, 420 psi operating pressure.
122.212	Valves	
122.2121	Sequencing valves	6 - Rockwell trunion mounted ball valves, 36 inch diameter electric motor operated, 420 psi operating pressure.
122.2122	Pressure control valve	DeZurik eccentric valve, pneumatic-cylinder actuated, 36 inch size 420 psi operating pressure.
122.213	Fittings	
122.2131	Elbows	3 - 36 inch long radius elbows, 420 psi operating pressure.
122.2132	Tee	3 - 36 inch size, 420 psi operating pressure.
122.2133	Reducer	As necessary to connect 36 inch pipe to intercoolers and moisture separators.
122.2134	Instrument fittings	See item 143.21.

Account No.	Equipment	Description
122.214	Hangers and supports	As required to allow expansion of system piping.
122.215	Miscellaneous material	As required.
122.2151	Paint	As required.
122.2152	Insulation	None required.
122.22	Remaining three plants (77 wells each)	
122.221	Piping	Approximately 70,000 pounds of 36 inch steel pipe connecting various surface plant hardware components, 300 psi operating pressure.
122.222	Valves	Fabricated.
122.2221	Sequencing valve	6 - Rockwell trunion mounted ball valves, 36 inch diameter electric motor operated, 300 psi operating pressure.
122.2222	Pressure control valve	DeZurik eccentric valve, pneumatic cylinder actuated, 36 inch size, 300 psi operating pressure.
122.223	Fittings	As required.
122.2231	Elbows	1 - 36 inch long radius.
122.2232	Tee	3 - 36 inch size.
122.2233	Reducer	Necessary reducers to connect 36 inch pipe to intercoolers and moisture separators.
122.2234	Instrument fittings	See item 143.21.
122.224	Hangers and supports	As required to allow expansion of system piping.
122.225	Miscellaneous material	
122.2251	Paint	As required.
122.2252	Insulation	None required.

H.4 TURBOMACHINERY

ACCOUNT 141. GAS TURBINE, MOTOR-GENERATOR, COMPRESSOR

Account No.	Equipment	Description
141.1	Gas turbine	150 MW_e, single-shaft, 3600 rpm turbine, including combustor.
141.2	Motor-generator	14,400 V, 0.9pf. 3-phase, 3600 rpm, hydrogen cooled.
141.3	Main compressor	11:1 axial compressor, 36,000 rpm.
141.34	Booster compressor	2:1 compressor driven by HP electric motor; constant speed.
141.41	Inlet duct equipment	
141.411	Inlet duct	
141.412	Silencer	Glass wool perforated metal on interior of compartment sides and roof panels, to lower sound pressure to 57 dBA.
141.412	Inlet filter	Inertial separator and high efficiency fixed media filtration.
141.42	Exhaust duct equipment	
141.421	Exhaust duct	
141.422	Exhaust duct silencer	Glass wool, perforated metal on interior of compartment side and roof to lower sound to 57 dBA.
141.43	Regenerator	
141.431	Regenerator	2 - extended surface, plate-fin gas-to-air heat exchangers.
141.432	Regenerator piping	Final welding and fabrication performed in field.
141.44	Intercoolers	
141.441	First stage intercoolers	20 - 36 foot long by 11 foot wide air-cooled heat exchanger bays, connected to form single unit. Each bay contains two 10 foot diameter forced draft fans.

Account No.	Equipment	Description
141.442	Second stage intercooler	8 - 36 foot long × 11 foot air-cooled heat exchanger bays connected to form a single unit. Each bay contains two 10 foot diameter forced draft fans.
141.45	Moisture separators	
141.451	After first stage intercooler	Burgess model V-700, 16 inch inlet and outlet vane separator, 75 gpm effluent connected to sewage effluent discharge.
141.451	After second stage intercooler	Identical to separator after first stage intercooler; discharge is 20 gpm.
141.46	Chiller-heater	To cool air from initial plant only to 60 F, remove moisture and reheat to 150 F - 200 F.
141.461	Heat exchangers	
141.4611	First stage	Shell and tube, to cool air to 100 F via first stage cooling tower.
141.4612	Second stage	Shell and tube, to cool air to 60 F via chilled water system.
141.4613	Third stage	Shell and tube, to warm air to 150 F - 200 F via exit air from auxiliary compressor.
141.462	Cooling towers	
141.4621	First stage	Marley model #8602 wet cooling tower with 5 hp motor to provide water at 90 F to first stage heat exchanger.
141.4622	Second stage	Marley model #8611 wet cooling tower with 20 hp motor to provide chilled water to second stage heat exchanger.
141.463	Refrigeration unit	360 ton, chilled water, self-contained refrigeration unit 275 kW electric load.
141.464	Pumps	

Account No.	Equipment	Description
141.4641	First stage cooling	2 - centrifugal pumps, electric motor driven to provide redundancy for 900 F water circulating system, 250 gpm each.
141.4642	Second stage cooling	2 - centrifugal pumps, electric motor driven to provide redundancy for chilled water circulating system.
141.4643	Refrigeration unit to cooling tower (condenser)	2 - centrifugal pumps, electric motor driven to provide redundancy for refrigeration unit condenser system 1200 gpm each.
141.4644	Water make-up system	To provide water makeup for chilled system, 30 gpm capacity.
141.5	Starting and accessory skid	1200 hp starting motor, hydraulic torque converter, jaw clutch, turning gear and motor, fuel oil pump and running atomizing air compressor.
141.6	Lube oil skid and connecting piping	Lube oil reservoir, main lube pump, emergency lube pump, auxiliary and emergency generator seal pump, and lube oil heaters.
141.7	Control cabinet	Turbine control panel generator control panel, motor control center, lighting transformer, located in main control building.
141.81	Disconnect couplings	
141.811	Turbine-to-generator	Hydraulically actuated spline gear coupling; engagement only when stationary, disengagement at full speed, low load.
141.812	Generator-to-axial compressor	Hydraulically actuated spline gear coupling; engagement and disengagement only when stationary.

Account No.	Equipment	Description
141.91	Equipment foundations	
141.911	Gas turbine, motor-generator axial compressor, all turbo-machinery skids, regenerator	132 x 98 ft 4 in x 6 ft thick; 2885 yd^3.
141.912	First stage intercooler	220 ft x 36 ft x 6 ft thick; 1760 yd^3.
141.913	Auxiliary compressor	50 ft x 20 ft x 6 ft thick; 223 yd^3.
141.914	Second stage intercooler	88 ft x 36 ft x 6 ft thick; 764 yd^3.
141.915	Auxiliary cooling compartment	38 ft x 10 ft x 6 ft thick; 8.5 yd^3.
141.916	Chiller-heater	
141.9161	Cooling towers	
141.9161	First stage	15 ft x 10 ft x 3 ft thick; 17 yd^3.
141.9162	Second stage	24 ft x 12 ft x 3 ft thick; 32 yd^3.
141.9162	Refrigeration unit	20 ft x 10 ft x 6 ft thick; 45 yd^3.
141.9163	Heat exchangers	3 to 6 ft x 2 ft x 3 ft thick; 1.5 yd^3 each.
141.917	Initial aquifer development compressor	
141.95	Enclosures for equipment	
141.951	Gas turbine, regenerator	Supplied by vendor.
141.952	Compressor	
141.953	Intercoolers	None required.
141.96	Turbomachinery auxiliaries	
141.961	Fire protection system	
141.9611	Turbomachinery, vendor supplied	High-pressure CO_2 system with detectors, supplied from 6 high-pressure cylinders located in accessory compartment.

Account No.	Equipment	Description
141.9612	Field supplied	One-inch hose connections and 50 foot hose pipe connection, provided at 100 foot intervals in turbine generator enclosure.
141.962	Fuel oil	
141.9621	Distillate oil fuel system	Shaft driven fuel pump, ten atomizing fuel nozzles, shaft driven centrifugal air compressor, shell and tube air-to-water heat exchanger, and starting atomizing air compressor.
141.9622	Liquid fuel forwarding system	480 VAC fuel forwarding pump, immersion heaters and motor control center.
141.9623	Ignition system	2 - ignition transformers and 2 - spark plugs.
141.9631	Lube oil system	Mounted and self-contained on lube oil skid.
141.964	HVAC	A-C heaters-immersion lube oil heaters; space heaters for control, accessory, turbine, switchgear, and exciter compartments, battery heaters.
141.9641	Ventilation	Control compartment air-conditioner, turbine compartment fan, load coupling compartment fan, accessory compartment fan.

ACCOUNT 142. FUEL OIL SYSTEM EQUIPMENT

Account No.	Equipment	Description
142.1	Fuel oil storage tank	6,000,000 gallon capacity complete with level gauge, ladder, vents and vacuum breaker (124 ft diameter × 67 ft high). Furnish, erect, and hydro test.
142.14	Foundation	Excavation, backfill, concrete, sand cushion, steel sump pit. Furnish and install.

Account No.	Equipment	Description
142.18	Dike	
142.181	Earth dike	
142.182	Access stairs	Provided at two locations.
142.183	Barrier	Bentonite or similar material to prevent leakage of oil into sub-surface soil or water table.
142.184	Sump pump	25 gpm, centrifugal pump, electric motor drive.
142.185	Lightning protection	According to standard codes and practices.
142.186	Grounding material	According to standard codes and practices.
142.187	Area lighting	According to standard codes and practices.
142.2	Unloading station	
142.42	Pumps	3 - 250 gpm 6 x 4 centrifugal pumps, electric motor drive, 50 psig delivery pressure.
142.22	Piping	
142.221	Flexible hose	6 inch flexible hose from pump suction to fuel oil carrier.
142.222	Pump-to-manifold	4 inch pipe.
142.223	Manifold to top of tank	6 inch pipe.
142.224	Fittings	As required.
142.23	Valves	
142.231	Shutoff valves	4 inch gate valve.
142.232	Backflow valves	6 inch check valve.
142.24	Instrumentation	
142.241	Flow meter	As required.
142.242	Pressure gauge	As required.
142.25	Filter	As required.
142.3	Tank to turbine fuel transfer system	

Account No.	Equipment	Description
142.31	Pumps	2 - 8 x 6 in-line centrifugal pumps, 50 psig, 200 gpm electric motor driven, arranged in parallel to provide redundancy.
142.32	Piping	
142.321	Tank to pump inlet	500 foot 8 inch Sch 40 steel pipe.
142.322	Pump to turbine	1000 foot 6 inch Sch 40 steel pipe.
142.33	Valves	
142.331	Shutoff valves	
142.3311	Pump inlet	2 - 8 inch gate valves, 150 lb.
142.3312	Pump outlet	2 - 6 inch gate valves, 150 lb.
142.3313	Turbine inlet	2 - 4 inch gate valves, 150 lb.
142.332	Backflow valves	
142.3321	Pump inlet	1 - 8 inch check valve, 150 lb.
142.3323	Turbine inlet	2 - 4 inch check valves, 150 lb.
142.34	Instrumentation	
142.341	Pressure gauge	As required at each pump discharge.
142.35	Filters	As provided by gas turbine vendor.
142.36	Miscellaneous	
142.361	Coating for underground pipe	As required.
142.362	Pipe supports	As required.
142.363	Grounding	According to standard practices.
142.364	Lighting protection	Accroding to standard practices.

ACCOUNT 143. INSTRUMENTATION AND CONTROL

Account No.	Equipment	Description
143.1	Turbomachinery	
143.11	Control systems	
143.111	Startup control system	Automatic or manual.

Account No.	Equipment	Description
143.112	Accelerator control system	Automatic or manual.
143.113	HP and LP speed control system	Automatic or manual.
143.114	Temperature and fuel rate control system	Automatic or manual.
143.115	Nozzle control system	Automatic or manual.
143.116	Load control system	Automatic or manual.
143.117	Pulsator control system	Automatic or manual.
143.12	Protection systems	
143.121	Overspeed protection system	Monitor, alarm trip.
143.122	Overtemperature protection system	Monitor, alarm trip.
143.123	Vibration protection system	Monitor, alarm trip.
143.124	Safe stop protection system	Monitor, alarm trip.
143.125	Flame protection system	Monitor, alarm trip.
143.126	Ground protection system	Monitor, alarm trip.
143.13	Sequencing systems	
143.131	Normal start system	
143.132	Fast start system	
143.133	Multiple start system	
143.135	Emergency stop system	
143.136	Zero speed detection system	
143.137	HP and LP detection speed system	
143.2	Compressed air instrumentation	
143.21	Surface plant	
143.211	Pressure measurement system	In line transducers downstream of main compressor, auxiliar compressor and each intercoc Readout in control building via multiple recorder.

Account No.	Equipment	Description
143.212	Flow measurement system	Downstream of final inter-cooler, readout in control building.
143.213	Temperature measurement system	Downstream of main compressor, auxiliary compressor and each intercooler. Readout in control building via multiple recorder.
143.22	Distribution manifold	
143.221	Pressure measurement system	In line transducers at each branch connection point of manifold. Readout in control building via multiple recorder.
143.222	Flow measurement system	Fittings at each wellhead to permit onsite flow measurement.
143.223	Temperature measurement system	None required.

H.5 ELECTRIC PLANT EQUIPMENT

ACCOUNT 151. SWITCHGEAR

Account No.	Equipment	Description
151.1	Generator switchgear	Supplied by turbomachinery vendor.
151.2	Plant auxiliary service	
151.21	High voltage, a-c	
151.211	Motor switchgear	14.4, kV-2000 A, auxiliary compressor, motor switchgear, including main breaker, starting equipment, etc.
151.2111	Foundations	24 yd^3.
151.22	Low voltage, a-c	
151.221	Motors	14.4 kV - 480 V switchgear w/1500 kVA transformer and M.C.C.
151.2211	Foundations	16 yd^3.

ACCOUNT 152. STATION SERVICE

Account No.	Equipment	Description
152.2	120/280 V a-c system	
152.21	Switchgear	14.4 kV - 120/208 V, switchgear with 500 kVA transformer and 3-phase, 4-wire, a-c distribution panels.
152.211	Foundation	12 yds^3.
152.3	125 V d-c system	
152.31	Battery	125 V d-c, 300 Ah, lead calcium type, 60 cell, 50 A Continuous at 130 V d-c.
152.32	Charger	

ACCOUNT 153. SWITCHBOARDS

Account No.	Equipment	Description
153.12	Control of relay panels	8 unit duplex lineup with center aisle.
153.22	125 d-c distribution panels	200 A main bus and 60 A fuse holders.

ACCOUNT 154. PROTECTIVE EQUIPMENT

Account No.	Equipment	Description
154.1	Grounding	
154.11	Main ground grid	4/0 copper cable with Cadweld connections.
154.2	Fire protection system for transformers	
154.3	Switchyard and lighting	400 W, mercury vapor type fixtures.

ACCOUNT 155. HIGH VOLTAGE ELECTRIC STRUCTURES AND WIRING (14.4 kV)

Account No.	Equipment	Description
155.1	Cable trough	320 - 5 ft sections. Precast concrete with grating cover.

Account No.	Equipment	Description
155.4	14.4 kV bus	2 - 12 inch aluminum channels per phase on post insulators.
155.41	Duct runs	3000 feet 15 kV, 3/c #4 aluminum cable with air duct
155.42	Channels	160 - 3-phase foot 12 inch aluminum channel
155.43	Cable	10,000 foot 15 kV - 1/c 1500 MCM aluminum cable.
155.44	Insulators	36 - 15 kV station post insulation.
155.45	Disconnect switches	
155.451	2000 A	4 - 14.4 kV, 3-phase.
155.452	1000 A	4 - 14.4 kV, 3-phase.
155.46	Potheads	30 - 15 kV.
155.47	Miscellaneous hardware	
155.471	14.4 kV bus hardware	
155.472	Disconnect switch stand	
155.48	Bus support foundation	16 yd^3.

ACCOUNT 156. POWER AND CONTROL WIRING 14.4 kV and 345 kV

Account No.	Equipment	Description
156.2	Station service power	
156.21	Cable for transformers, GCB's	12,000 foot 3/c - #6, 1/c - #1/0.
156.22	Control cable	36,000 foot, 12/c - #12, 5/c - #10.
156.23	Trench	250 - 5 foot sections precast concrete with concrete covers.

ACCOUNT 157. SWITCHYARD STRUCTURES

Account No.	Equipment	Description
157.1	Structures	
157.11	345 kV towers	4 required.
157.12	Bus supports	

Account No.	Equipment	Description
157.121	High	9 required.
157.122	Low	35 required.
157.13	345 kV switchstands	22 required.
157.14	CCPD stands	14 required.
157.15	Foundation	260 yd^3.
157.2	Transformers	2 - 345 kV - 14.4 kV, 220 MVA transformer with bushings, surge arresters.
157.21	Foundation	150 yd^3.
157.3	Circuit breaker	6 - 345 kV, 2000 A. Gas Circuit breakers.
157.31	Foundation	135 yd^3.
157.4	Disconnect switches	
157.41	Transformer	2 - 345 kV, 1200 A, disconnects.
157.42		18 - 345 kV, 2000 A, disconnects.
157.43	Line	4 - 345 kV, 2000 A, disconnects.
157.5	Capacitance coupled potential device	14 - 345 kV 120/67.08 V.
157.6	Line trap	2 - 345 kV, 2000 A.
157.7	Surge arrestor	12 - 345 kV.
157.8	Other bus and insulation equipment	
157.81	Primary bus	2600 foot - 3 1/2 inch IPS Sch 40 aluminum bus. 4000 foot - 3 inch IPS Sch 40 aluminum bus.
157.82	Insulators	300 - 345 kV station post insulators.
157.83	Miscellaneous hardware	As required.
157.9	Miscellaneous electrical work	As required.

Account No.	Equipment	Description
158.1	Structure	
158.11	Poles	10 - 100 foot high steel poles.
158.12	Foundation	400 yd^3.
158.2	Insulators and hardware	66 strings.
158.3	Cable	29,000 foot 954 MCM ACSR cable.
158.4	Static wire	10,000 foot alumoweld static wire.

ACCOUNT 159. RELAY HOUSE

Account No.	Equipment	Description
159.1	Structure	one 20 ft x 30 ft prefabricated house.
159.2	Foundation	20 yd^3.
159.3	Utilities	As required.

H.6 MISCELLANEOUS EQUIPMENT

ACCOUNT 161. VEHICULAR EQUIPMENT

Account No.	Equipment	Description
161.1	Transportation equipment	
161.11	Personnel and portable equipment transportation	2 - 4-wheel-drive offroad van-type vehicles, each equiped with remote radio telephone communication system.
161.12	Heavy equipment transportation.	Any equipment is rented as required.
161.13	Lifting equipment	
161.131	Heavy lifting equipment (over 5 tons)	Equipment to lift up to 150 tons is rented as required.
161.132	Light lifting equipment (up to 5 tons)	5 ton electric bridge crane in spare parts storage facility.

ACCOUNT 162. PLANT SERVICE SYSTEMS

Account No.	Equipment	Description
162.1	Compressed air system	

Account No.	Equipment	Description
162.11	Compressor	2 - 100 psig, 100 SCFM air compressors, connected in parallel for redundancy, located to provide a pneumatic actuated pressure control valve for both 150 MWe clusters.
162.12	Piping	
162.13	Valves	
162.131	Shutoff valves	Gate valve.
162.132	Relief valves	Spring loaded plug valve.
162.133	Check valves	
162.134	Instrumentation	Mounted at system location; no control building readout.
162.2	Water service system	Standard plumbing and service water system for workmen's sanitary facilities.
162.3	Electrical service system	Redundant service supplied from each two-unit cluster. Detail described in account code 5.

ACCOUNT 163. COMMUNICATION AND EQUIPMENT

Account No.	Equipment	Description
163.1	Telephone	
163.11	Surface plant	Telephone receivers at 500 yard intervals in weatherproof enclosures.
163.12	Distribution manifold	Telephone receivers at 500 yard intervals in weatherproof enclosures.
163.13	Control building	Telephone receiver at various operating location in control building.

ACCOUNT 164. FIXTURES AND FURNISHINGS

Account No.	Equipment	Description
164. 1	Sanitary facilities	To accommodate up to 6 workmen.
164. 2	Change house facilities	
164. 21	Showers	To accommodate up to 6 workmen.
164. 22	Lockers	To accommodate up to 24 workmen.
164. 3	Lunchroom facilities	As necessary to accommodate 8 workmen.

H.7 MACHINE SHOP

ACCOUNT 165. LABORATORY AND TEST EQUIPMENT

None required.

Appendix I

ESTIMATE OF COSTS FOR 600 MW CAES PLANT

Description	Quantity	Unit	Amounts ($)	Alternative 1 Initial ($)	Alternative 1 Final ($)
YARD WORK					
Clear and rough grade site	—	—	Not included	—	—
Fine grade and surface gas turbine area with crushed stone	800,000	SF	100,000	50,000	50,000
Fencing and gates	150,000	LF	1,100,000	1,000,000	—
* Paved roads and parking areas	Allow	—	50,000	25,000	25,000
* Railroad track	Allow	—	25,000	25,000	—
Yard Piping					
Storm drainage	None	—	—	—	—
Potable water (incl. wells)	Allow	—	25,000	25,000	—
Fire protection loop including hydrants-8" pipe	8,000	LF	350,000	175,000	175,000
Sanitary sewer from Central Control Building to treatment plant plus effluent from treatment plant to Elkhorn Creek	—	—	25,000	25,000	—
Yard Lighting					
Perimeter fence at gas turbine plants Fuel oil unloading area Parking area and roads Walks	—	—	400,000	200,000	200,000
Fire Protection Equipment Elevated Water Storage Tank					
Steel tank, 65,000 gal capacity, approx. 25' dia. x 20' high, including foundation	2	Each	300,000	150,000	150,000
Fire pump - 750 gpm					
Diesel driven	2	Each	40,000	20,000	20,000
Motor driven	2	Each	30,000	15,000	
Jockey pump with motor drive, 25-50 gpm, 110 psi	2	Each	6,000	6,000	—
Pump foundations and enclosures	Allow	—	10,000	10,000	—
Hose houses	32	Each	29,000	15,000	14,000
Sewage Treatment Equipment					
Aerobic digestion process sewage treatment plant - 500 gal/day capacity	1	Each	10,000	10,000	—
TOTAL YARD WORK			2,400,000	1,751,000	649,000

*On site only

Description	Quantity	Unit	Amounts ($)	Alternative 1 Initial ($)	Final ($)
CENTRAL CONTROL BUILDING					
Single-story building, approx. 200' x 130', steel frame structure with insulated metal siding on reinforced concrete foundation. Partitioned to provide areas for control room, spare parts storage, change and locker facilities, and washrooms	—	—	—	—	—
Substructure					
Reinforced concrete slab on grade with grade beams, footings, etc.	26,000	SF	200,000	200,000	—
Superstructure					
Structural steel frame, insulated metal siding and roof, interior partitions, doors and sash, special finishes, painting	520,000	CF	400,000	400,000	—
Service Equipment					
Heating, ventilating, and air conditioning	520,000	CF	100,000	100,000	—
Lighting and service wiring	26,000	—	75,000	75,000	—
Plumbing and drainage	Allow	—	25,000	25,000	—
TOTAL CENTRAL CONTROL BUILDING			800,000	800,000	—
FUEL OIL SYSTEM					
Fuel oil storage tank 6-million gallon capacity, approx. 125' dia. x 67' high	2	Each	1,200,000	600,000	600,000
Reinforced concrete foundation	1,100	CY	200,000	100,000	100,000
Earth dike - 7' high	3,400	LF	100,000	50,000	50,000
Surface treatment for diked area	None	—	—	—	—
Truck and Tank Car Unloading					
Unloading pumps - 250 gpm @ 50 psig	6	Each	12,000	6,000	6,000
Reinforced concrete foundation	—	—	2,000	2,000	—
Concrete curb and gravel fill for spilled oil containment	Allow	—	20,000	20,000	—
Filter separator unit	2	Each	10,000	5,000	5,000
Fuel oil forwarding pumps - 200 gpm @ 50 psig, in-line design	4	Each	8,000	4,000	4,000

Description	Quantity	Unit	Amounts ($)	Alternative 1 Initial ($)	Final ($)
FUEL OIL SYSTEM (Cont'd)					
Foam type fire protection system, including foundations and piping	2	Each	200,000	100,000	100,000
Fuel oil piping from unloading area to storage tank, supply line from tank to gas turbines, and return line from gas turbines to storage tank 2" x 8" Sch. 40 carbon steel	4,200	LF	300,000	100,000	200,000
Tank level gage, pressure gages, flow meters, and other instrumentation	Allow		40,000	24,000	24,000
TOTAL FUEL OIL SYSTEM			2,100,000	1,011,000	1,089,000
GAS TURBINE GENERATOR COMPLEX					
Turbine Generator Unit					
Gas turbine Main compressor Motor/generator (rated 150 MW) Disconnect couplings Inlet filter, silencer, and duct Exhaust silencers and ducts Regenerators and connecting hot-air piping Lubricating oil skid and connecting piping Starting and accessory skid Electrical skid Prefabricated housings					
To furnish above	4	Units	43,704,000	10,926,000	32,778,000
Erection			2,000,000	500,000	1,500,000
Booster Compressor Unit					
Cfm compressor - 420 psi, with 48,000 hp motor drive					
To furnish	4	Each	8,510,000	2,128,000	5,289,000(a
Erection			500,000	125,000	308,000(a
Chiller-Heater for Initial Module Moisture Removal					
Heat exchangers	12	Each	120,000	30,000(b	—
Refrigeration system - 360T	4	Each	140,000	35,000(b	—
Cooling towers	8	Each	140,000	35,000(b	—
Miscellaneous pumps	24	Each	72,000	18,000(b	—
Erection of above equipment			48,000	12,000(b	—
Foundation work	400	CY	120,000	30,000(b	—

a) 3 each, Cfm compressors -- 290 psi with 29,000 hp motor drive.
b) Only one refrigeration system required.

Description	Quantity	Unit	Amounts ($)	Alternative 1 Initial ($)	Final ($)
GAS TURBINE GENERATOR COMPLEX (Cont'd)					
Intercoolers					
First stage - Air-to-air heat exchanger consisting of 20 - 36' x 11' bays connected to form a single unit; 2 - 10' dia. fans per bay with 40 hp motor drives					
To furnish above	4	Units	1,000,000	250,000	750,000
Erection	—	—	100,000	25,000	75,000
Second stage - Air-to-Air heat exchanger consisting of 8 - 36' x 11' bays connected to form a single unit, 2 - 10' dia. fans per bay with 30 hp motor drives					
To furnish above	4	Units	2,700,000	675,000	2,025,000
Erection	—	—	270,000	68,000	202,000
Equipment Foundations Reinforced concrete foundation for gas turbine generator units, booster compressors, and intercoolers (2 units)	22,000	CY	3,600,000	900,000	2,700,000
Moisture separators, erected	4	Each	30,000	8,000	22,000
TOTAL GAS TURBINE GENERATOR COMPLEX			63,054,000	15,765,000	45,649,000
ACCESSORY ELECTRIC EQUIPMENT					
Generator Leads From generator breaker to main power transformer -- 14.4 kV open bus, insulators, supporting steel, and foundations	4	Units	80,000	20,000	60,000
Main Power Transformer 300/400/500 MVA, 345 to 14.4 kV	2	Each	2,000,000	1,000,000	1,000,000
Reinforced concrete foundation	300	CY	60,000	30,000	30,000
Fixed water spray fire protection system	4	Each	40,000	10,000	10,000
Power Supply for Booster Compressor and Intercooler Fan Motors					
14.4 kV open bus from generator leads to disconnect switch	40	LF	20,000	5,000	15,000
Disconnect switch - 3-phase, 2000 ampere, incl. stand	4	Each	8,000	2,000	6,000
15 kV potheads	24	Each	10,000	3,000	7,000

Description	Quantity	Unit	Amounts ($)	Alternative 1 Initial ($)	Final ($)
ACCESSORY ELECTRIC EQUIPMENT (Cont'd)					
15 kV cable 1/C 1500 mcm	10,000	LF	80,000	20,000	60,000
Precast concrete trench for 15 kV cable	1,600	LF	50,000	12,000	38,000
15 kV Switchgear					
Booster compressor switchgear, incl. foundation	4	Each	190,000	48,000	142,000
48 Volt Switchgear					
14.4 kV - 480 volt switchgear with 1500 kVa transformer and motor control center for inter-cooler fan motors, incl. foundation	4	Each	160,000	40,000	120,000
Power Supply for Central Control Building and General Station Requirements					
15 kV potheads 15 kV cable - B/C No. 4 4" PVC duct, encased			12,000	12,000	–
Switchgear					
14.4 kV - 208/120 volt switchgear with 1000 kVa transformer (control building)	1	Each	75,000	75,000	–
600 volt cable (control building)	10,000	ft	10,000	10,000	–
Supervisory control terminals and wiring for remote control of units	–	–	100,000	25,000	75,000
General Plant Grounding	–	–	75,000	25,000	50,000
TOTAL ACCESSORY ELECTRIC EQUIPMENT			2,970,000	1,337,000	1,633,000
345 KV SWITCHYARD					
Yard Work					
Clear and rough grade	–	–	Not included	–	–
Fine grade and surface area with crushed stone	135,000	SF	20,000	20,000	–
Fencing and gates	750	LF	5,000	5,000	–
Switchyard lighting			20,000	20,000	–
Foundations					
Reinforced concrete foundations for bus supports, circuit breakers, disconnect switches, dead end towers	400	CY	80,000	20,000	60,000

Description	Quantity	Unit	Amounts ($)	Alternative 1 Initial ($)	Alternative 1 Final ($)
345 KV SWITCHYARD (Cont'd)					
Structures					
Steel structures for bus supports, dead end towers, etc.	250	Tons	200,000	50,000	150,000
Relay hours - 20' x 30'	600	SF	24,000	24,000	–
Switchyard Equipment					
Circuit breaker - 345 kV, 2000 ampere	7	Each	1,400,000	800,000	600,000
Disconnect switch - 345 kV					
1200 ampere	3	Each	75,000	50,000	25,000
2000 ampere	18	Each	540,000	135,000	405,000
Coupling capacitor potential device	14	Each	100,000	25,000	75,000
Line trap - 2000 ampere	2	Each	8,000	4,000	4,000
Surge arresters - 345 kV	15		60,000	15,000	45,000
Relay House Equipment					
Control and relay panels	Allow	–	125,000	125,000	–
Battery, charger, and distribution panels			10,000	10,000	–
345 kV Overhead Bus					
Insulators and hardware	300	Each	150,000	50,000	100,000
Aluminum tubing 3"-3-1/2"	6,600	LF	150,000	50,000	100,000
Aluminum cable 1250 mcm	1,700	LF	25,000	6,000	19,000
345 kV Pole Line from Remote Gas Turbine Units to Switchyard					
Steel poles and foundations	10	Each	160,000	–	160,000
Insulators and hardware	Allow	–	20,000	–	20,000
Aerial cable, incl. static wire	40,000	LF	40,000	–	40,000
Conduit and Wiring					
Precast concrete trench for power and control wiring	1,250	LF	25,000	25,000	–
600 volt power cable	12,000	LF	180,000	60,000	120,000
Grounding	Allow	–	41,000	21,000	20,000
Power Supply for Relay House and General Switchyard Requirements					
15 kV potheads 15 kV cable - 3/C No. 4 4' PVC duct, encased	Allow	–	12,000	12,000	–
Switchgear					
14.4 kV - 208/120 volt switchgear with 1000 kV transformer (station service at relay house)	1	Each	15,000	15,000	–

5

Description	Quantity	Unit	Amounts ($)	Alternative 1 Initial ($)	Final ($)
345 KV SWITCHYARD (Cont'd)					
TOTAL 345 KV SWITCHYARD			3,485,000	1,542,000	1,943,000
MISCELLANEOUS EQUIPMENT					
Cranes and Hoists					
Overhead crane for spare parts storage facility in Central Control Building - 5 ton capacity	1	Each	30,000	30,000	–
Erection	–	–	4,000	4,000	–
Mobile Equipment					
Off-road van type vehicles, 4-wheel drive, with remote radio-telephone communication equipment	2	Each	12,000	6,000	6,000
Telephone Communication Equipment					
Telephone equipment and wiring, weatherproof enclosures, etc.	Allow	–	25,000	12,000	13,000
Compressed Air System					
Air Compressor 100 scfm @ 100 psi compressor with motor drive and receiver	2	Each	20,000	10,000	10,000
Erection	–	–	5,000	2,000	3,000
Reinforced concrete foundation	Allow	–	1,000	1,000	–
Piping	Allow	–	30,000	15,000	15,000
Water piping for chiller/heater and moisture separators	Allow	–	23,000	8,000	15,000
Miscellaneous instruments and controls	Allow	–	100,000	50,000	50,000
Portable fire protection equipment	Allow	–	10,000	10,000	–
TOTAL MISCELLANEOUS EQUIPMENT			260,000	148,000	112,000
COMPRESSED AIR PIPING					
Interconnecting Piping Between Primary Compressors, Heat Exchangers, and Combustion Turbines					
Piping and fittings - 36" dia.	2,500	LF	400,000	100,000	300,000
Valves - motor operated sequencing - 36"	24	Each	700,000	175,000	525,000
Hangers and supports	Allow	–	70,000	18,000	52,000
Erection	–	–	420,000	105,000	315,000

Description	Quantity	Unit	Amounts ($)	Alternative 1 Initial ($)	Alternative 1 Final ($)
COMPRESSED AIR PIPING (Cont'd)					
Insulation	None	–	–	–	–
Painting	Allow	–	10,000	2,000	8,000
Distribution Piping at Aquifer					
Pipe and fittings	120,000	LF	4,380,000	980,000	3,400,000
Valves	Allow		1,160,000	260,000	900,000
Hangers and supports	Allow		773,000	173,000	600,000
Erection	–	–	3,607,000	807,000	2,800,000
Insulation	None	–	–	–	–
Painting	Allow	–	130,000	30,000	100,000
Burial to 6' depth	Allow	–	900,000	85,000	815,000
TOTAL COMPRESSED AIR PIPING			10,950,000	2,335,000	8,615,000
WELL COMPLETION					
Completion of 7.00 inch O.D. cased wells to bottom of Ironton-Galesville (800 ft)	308	Each	14,636,000	1,378,000	13,258,000
LAND					
Purchase	1,200	Acres	1,200,000	380,000	820,000
TOTAL LAND AND WELLS			15,836,000	1,758,000	14,078,000
OTHER COSTS					
Engineering and design			5,000,000	5,000,000	–
Construction supervision, temporary construction facilities, construction tools and equipment			4,000,000	1,000,000	3,000,000
TOTAL OTHER COSTS			9,000,000	6,000,000	3,000,000
SUBTOTAL OF YARD WORK					
Central control building, fuel oil system, gas turbine installation and accessories; miscellaneous equipment, accessory electric equipment, 345 kV switchyard and compressed air piping			38,825,000	16,634,000	21,624,000
CONTINGENCY 20% ON SUBTOTAL	–	–	7,765,000	3,327,000	4,325,000
TOTAL ORDER OF MAGNITUDE ESTIMATE AT DECEMBER 1975 PRICE LEVEL	–	–	118,620,000	35,774,000	81,093,000

Appendix J

BROOKVILLE STATION DRAWINGS

Arrangement plans and schematic diagrams have been prepared by United Engineers and Constructors Inc. for construction of a compressed air energy storage plant at Brookville, Illinois.

This appendix comprises the following drawings:

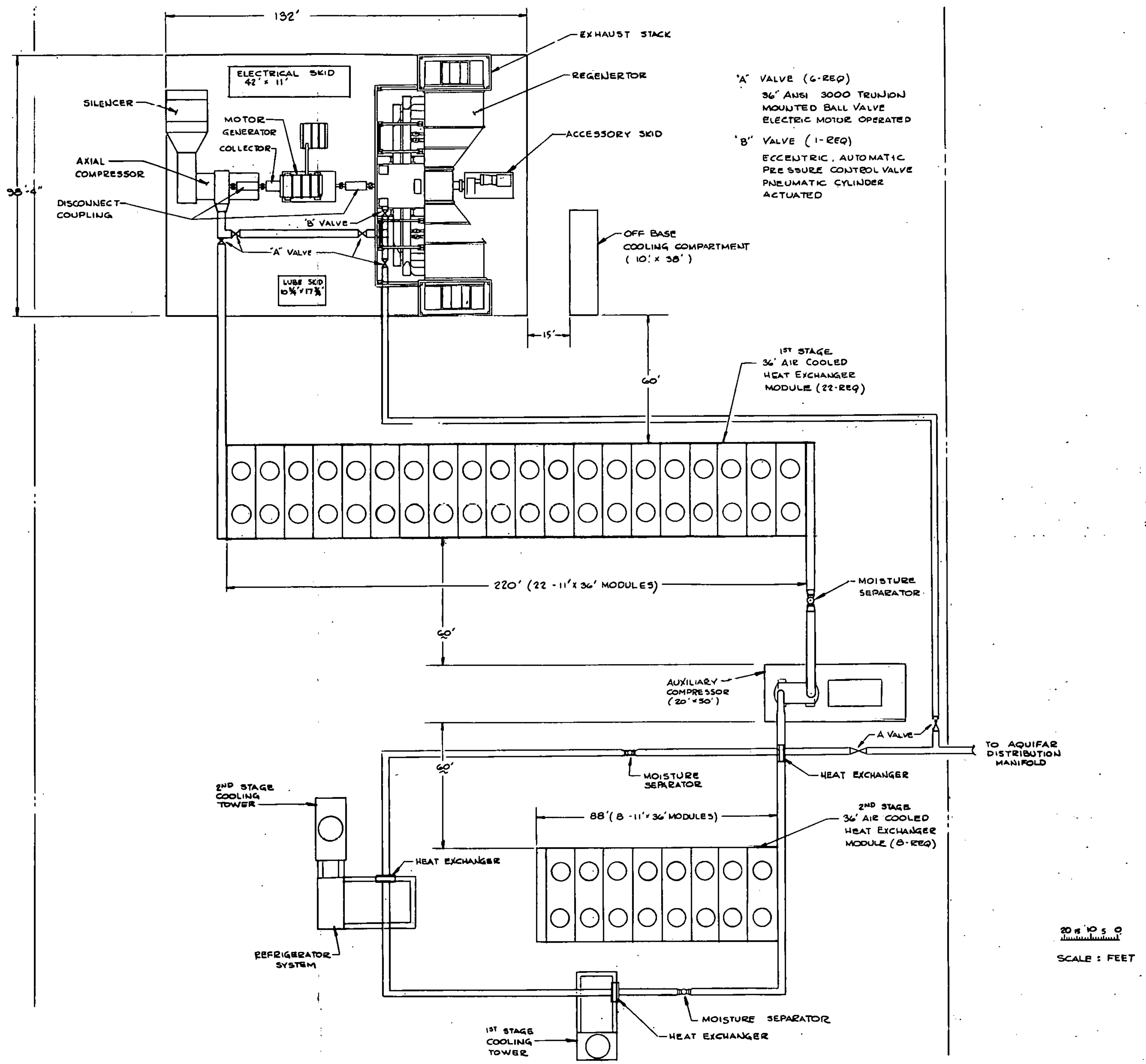
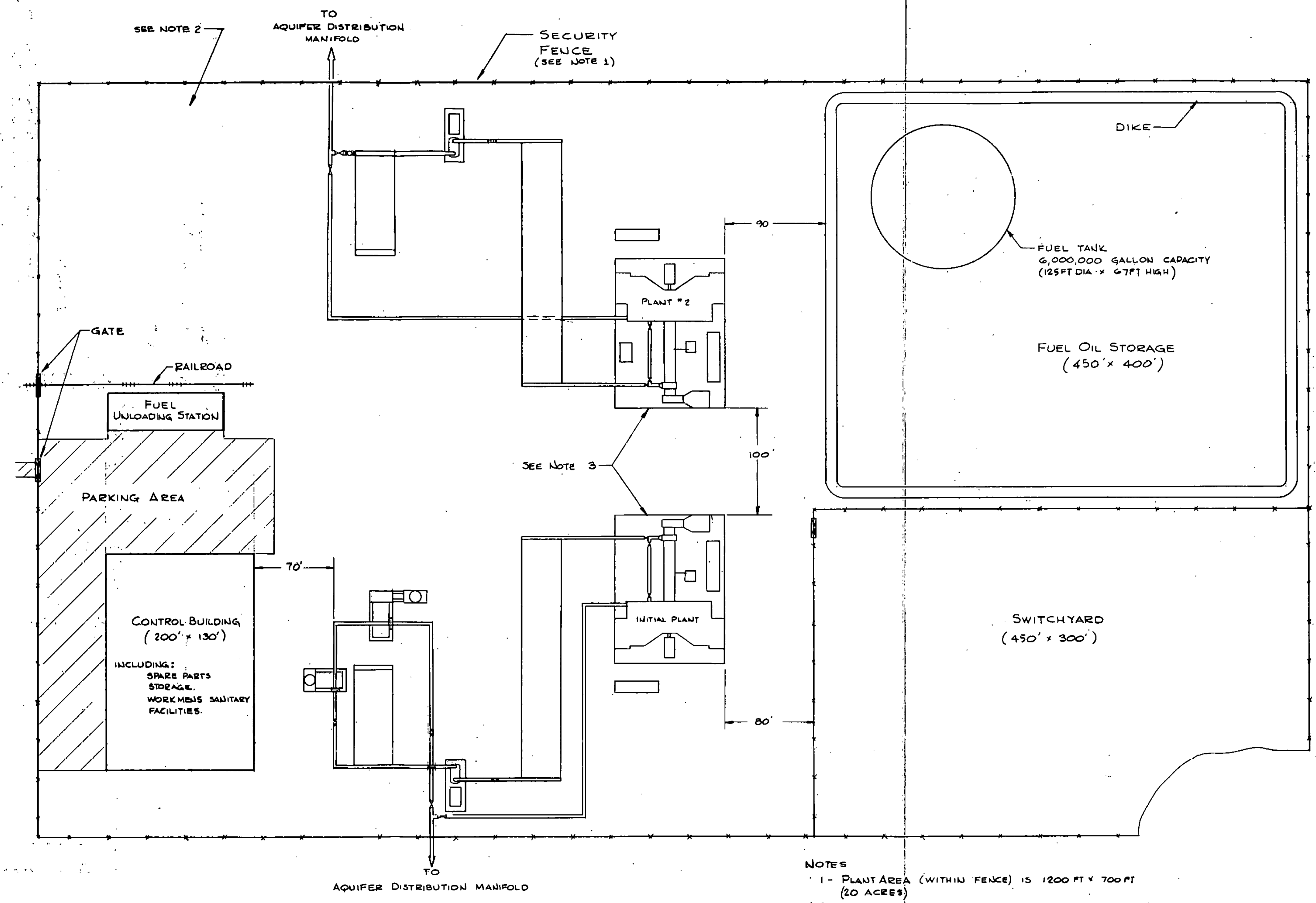


Figure J-1. Equipment Arrangement for Initial Plant



NOTES
1- PLANT AREA (WITHIN FENCE) IS 1200 FT × 700 FT (20 ACRES)
2- AREA BETWEEN FOUNDATION AND CONTROL BLDG/ PARKING AREA TO BE CRUSHED STONE SURFACE.
3- SEE 'UE-6354.009-D-008' AND 6354.016 FOR PLANT ARRANGEMENTS

Figure J-2. Partial Plot Plan -- 300 MW$_e$ Cluster with Control Building

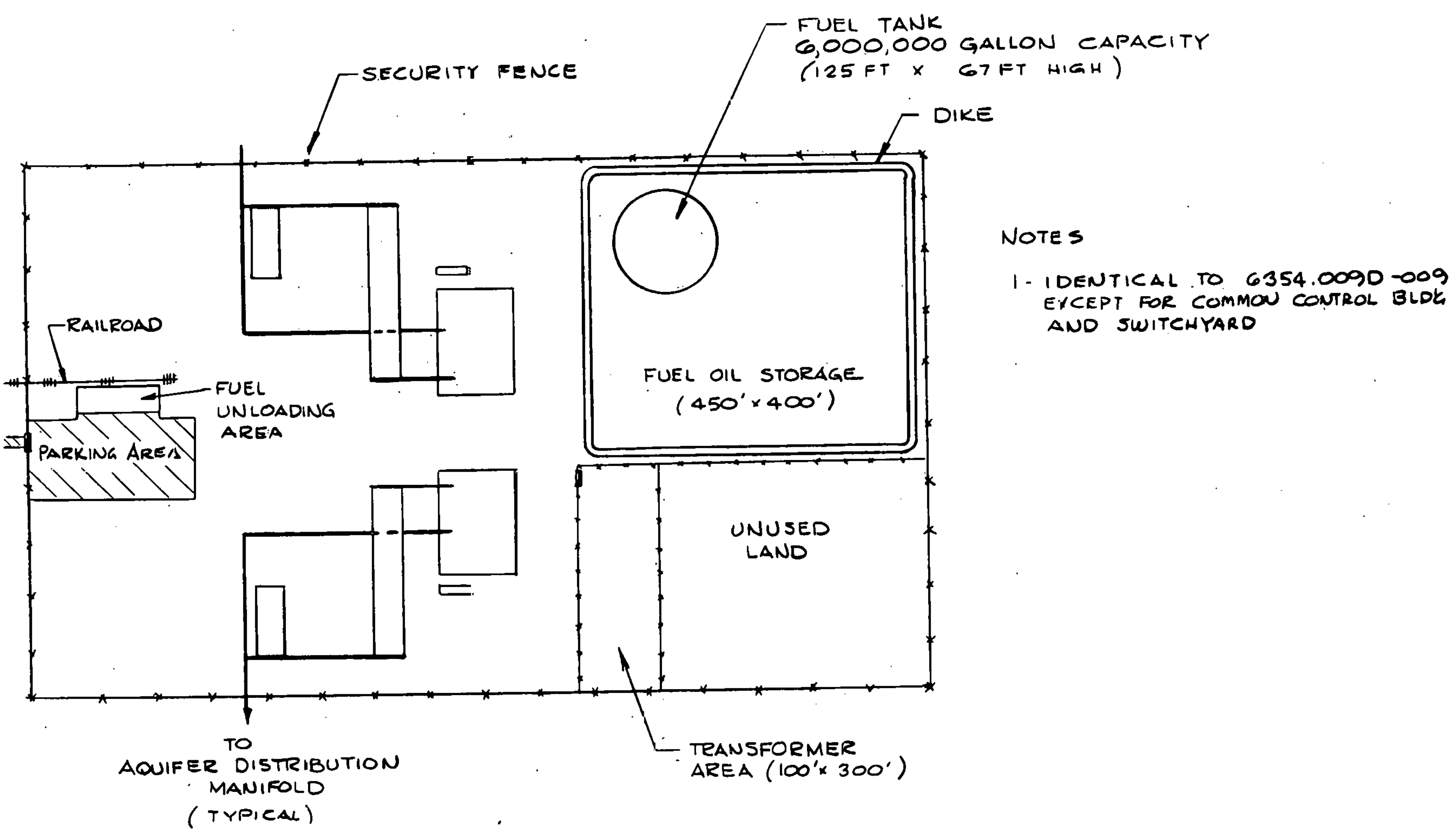


Figure J-3. Partial Plot Plan -- 300 MW_e Cluster without Control Building

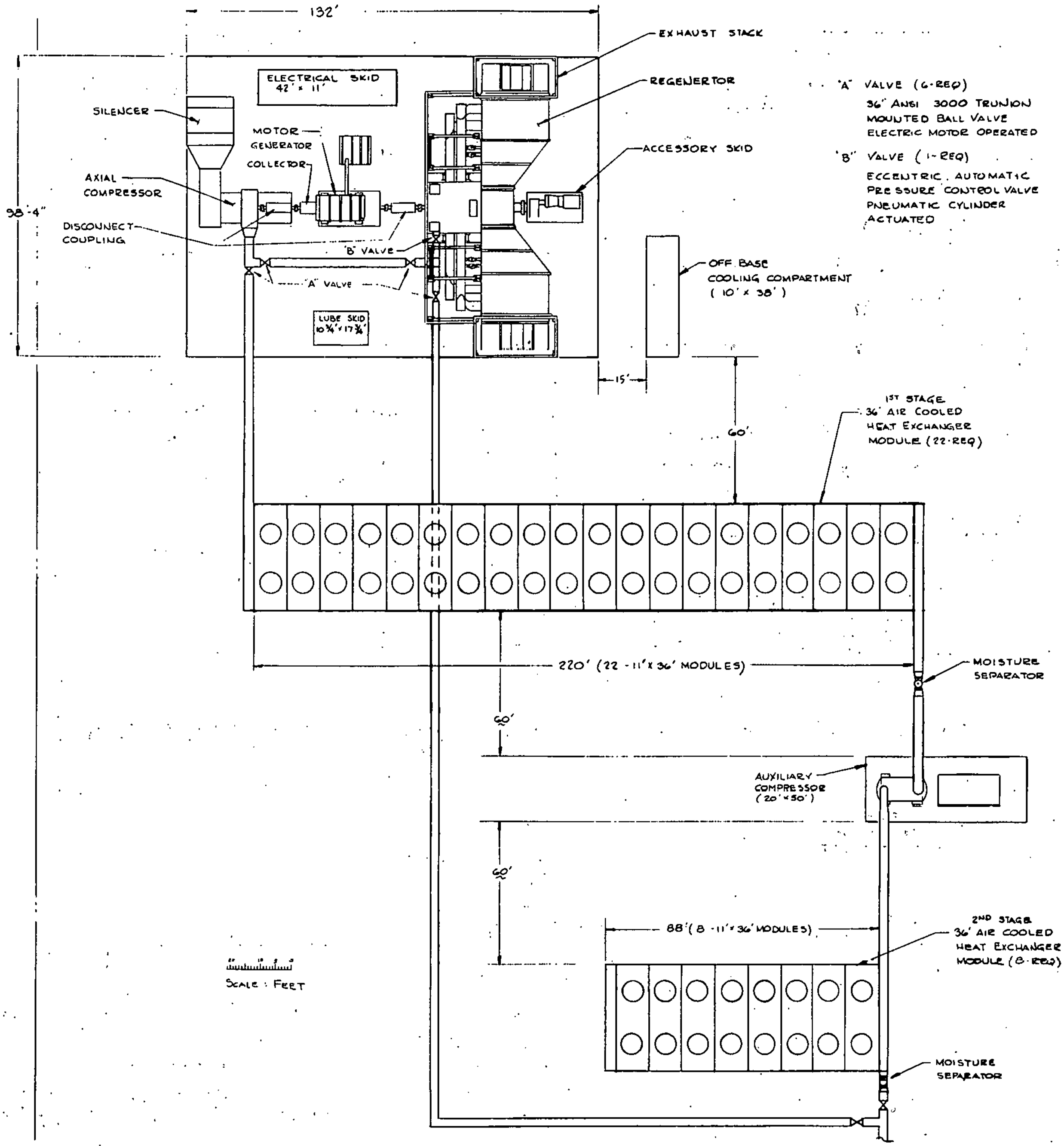


Figure J-4. Equipment Arrangement for Plants 2, 3, and 4

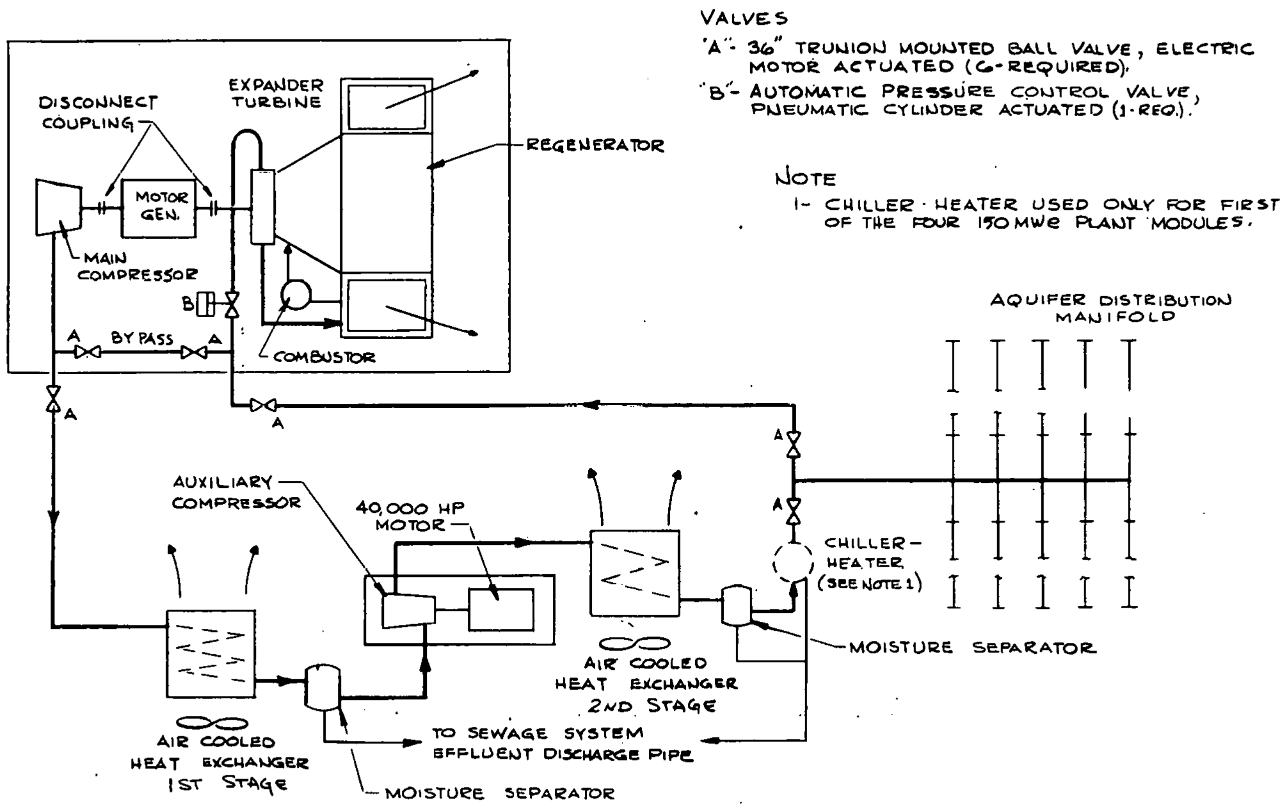


Figure J-5. Schematic Flow for Typical 150 MW_e Plant Module

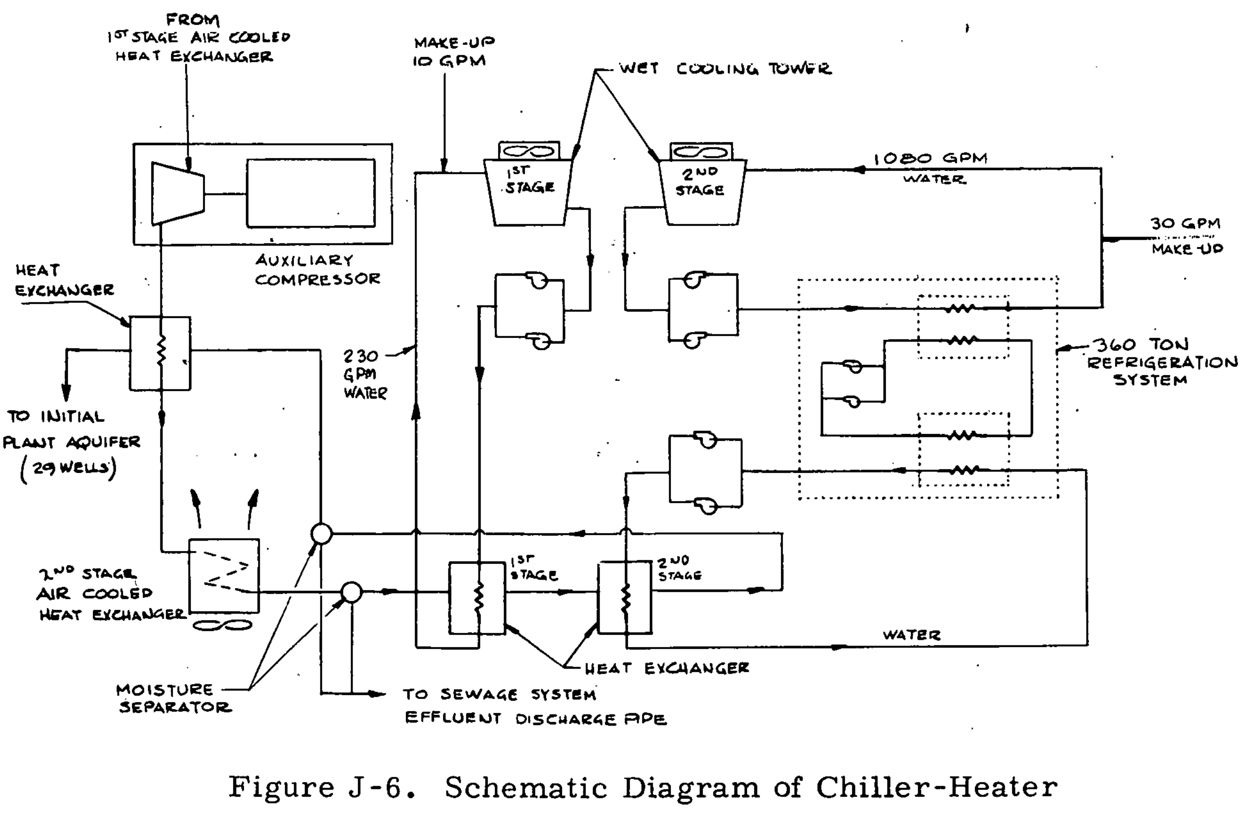


Figure J-6. Schematic Diagram of Chiller-Heater

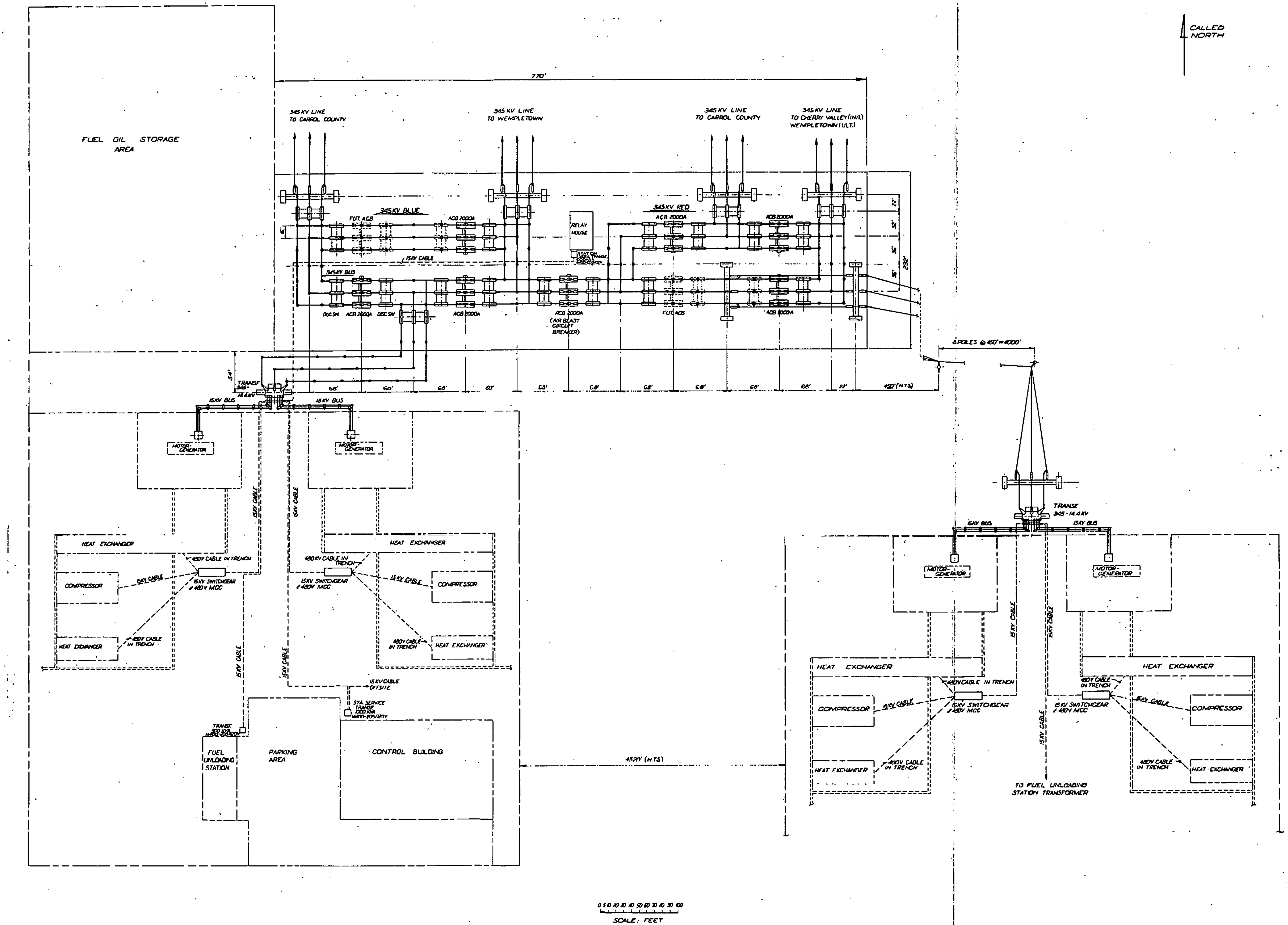


Figure J-7. Arrangement Plan for 345 KV Switchyard and 14.4 KV Power System

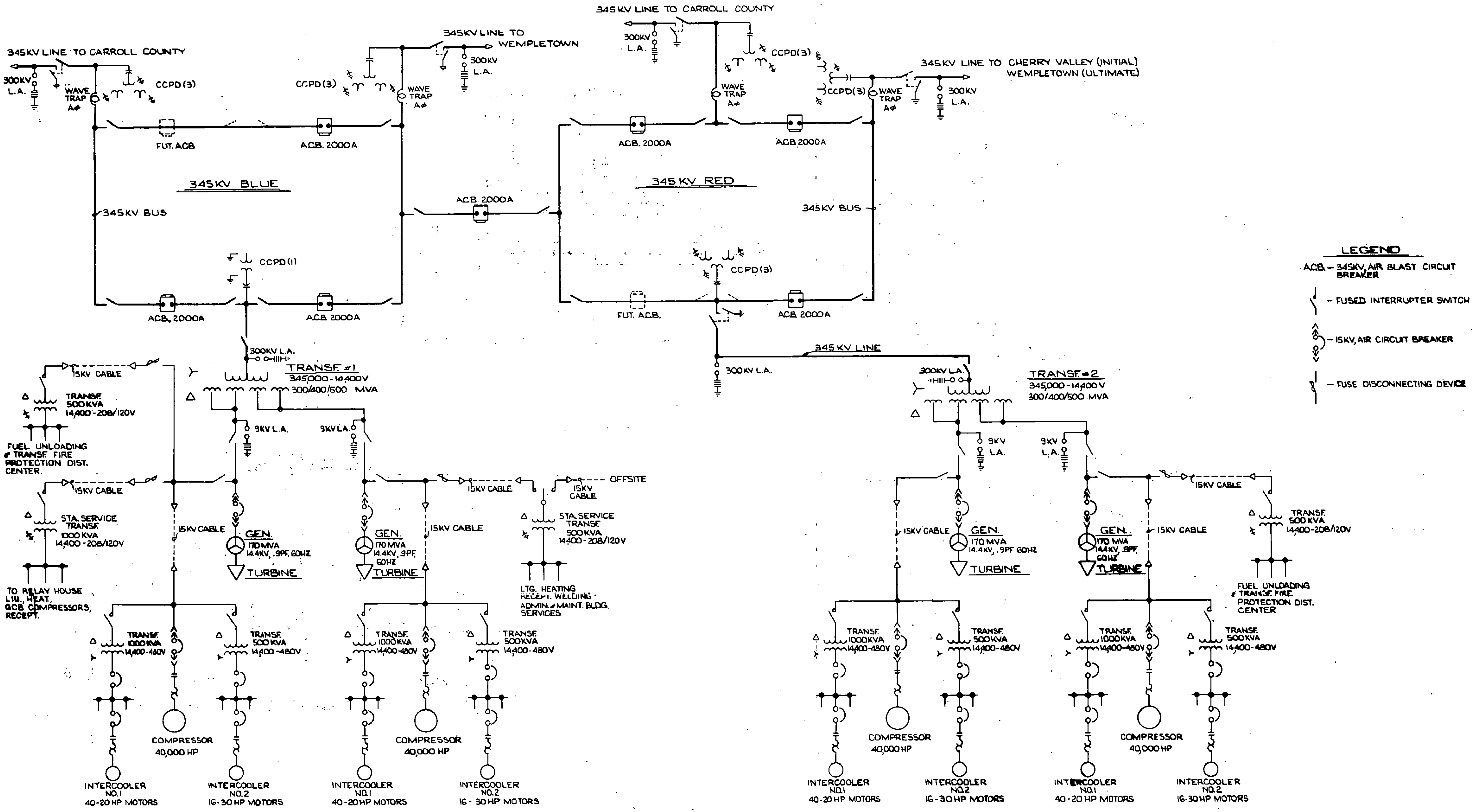


Figure J-8. One-Line Diagram for 345 KV Switchyard and 14.4 KV Power System

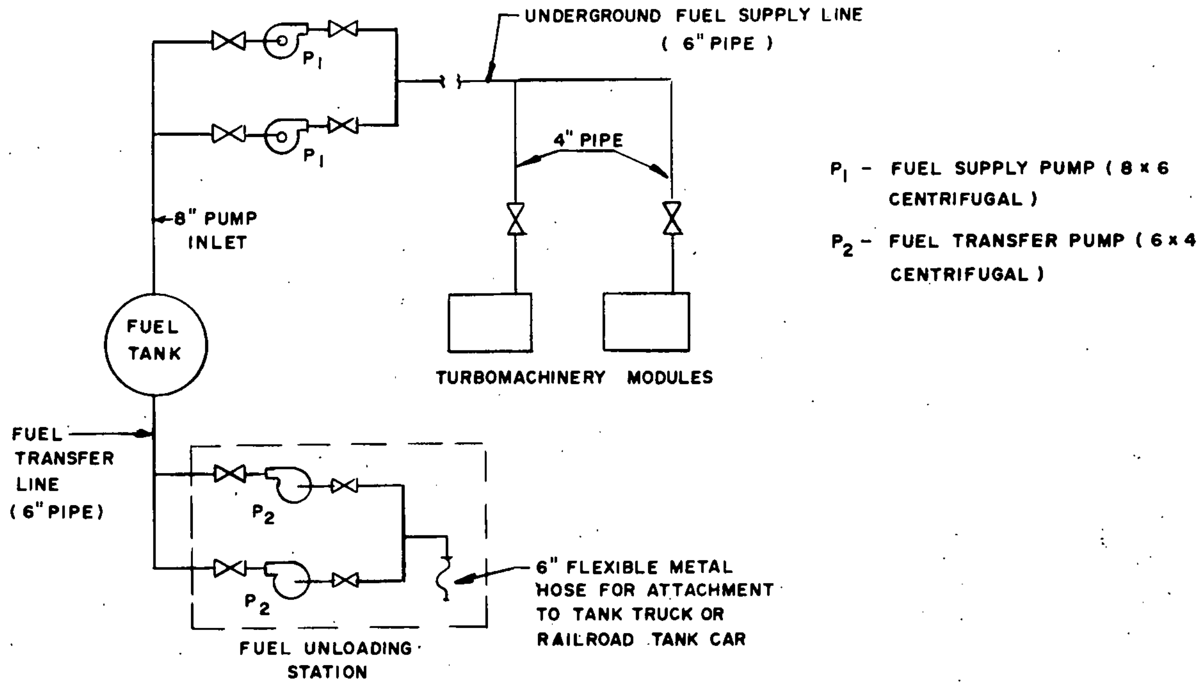


Figure J-9. Fuel Oil System

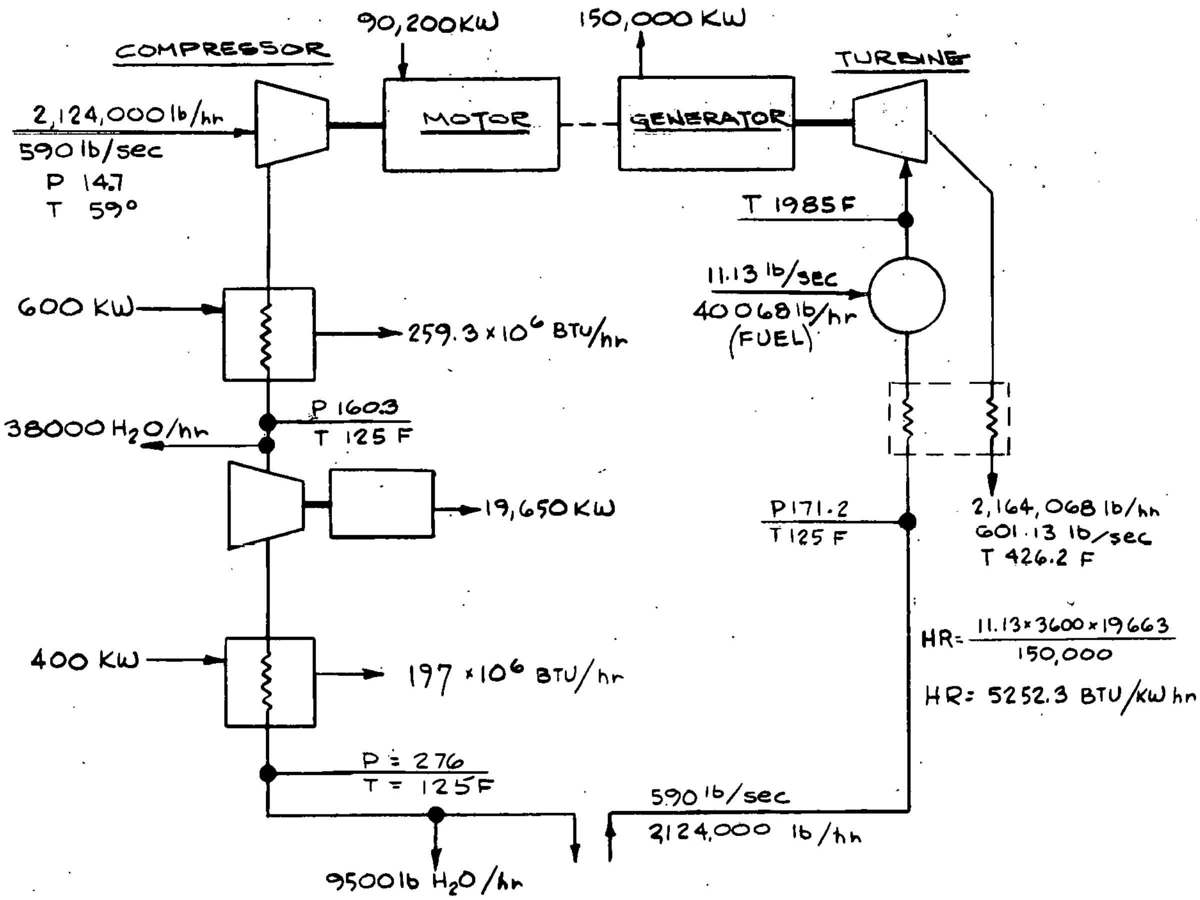


Figure J-10. Heat Mass Balance Diagram

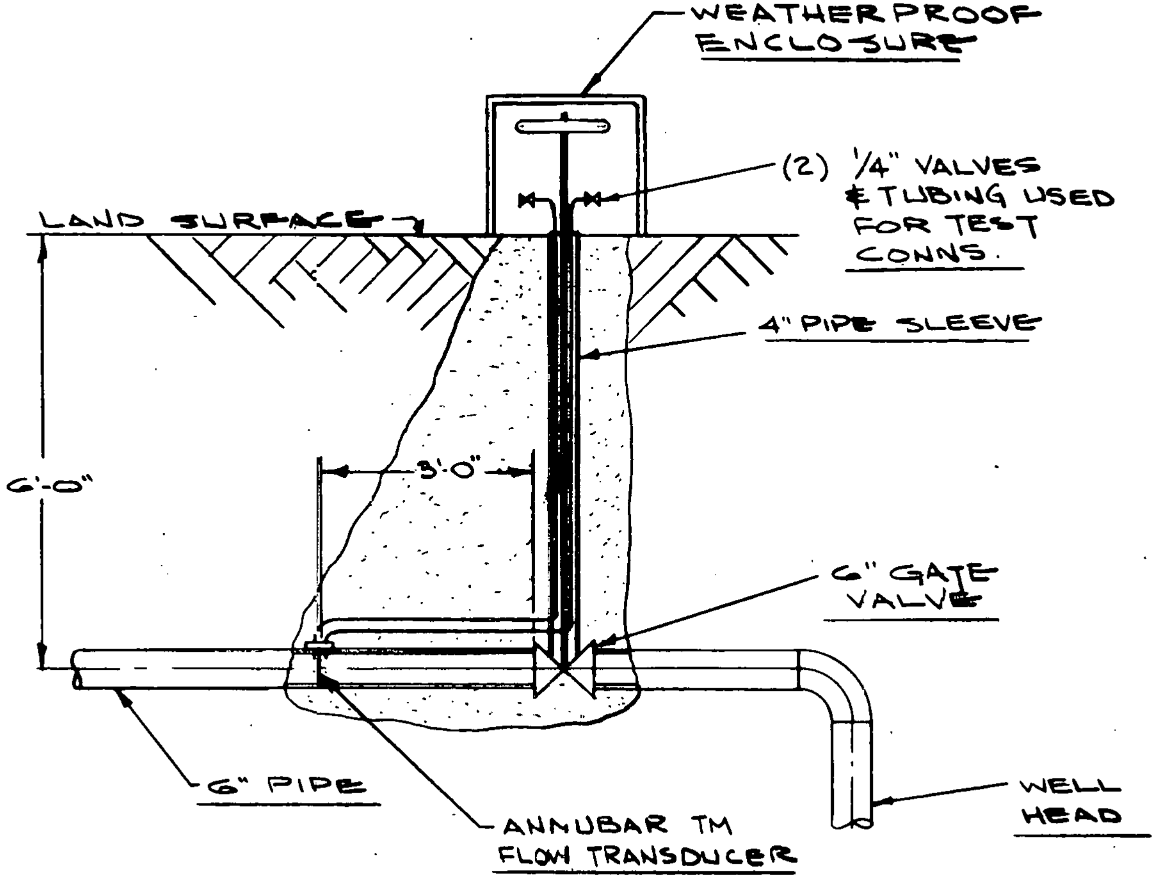


Figure J-11. Typical Buried Manifold/Wellhead

Appendix K

ECONOMIC EVALUATION OF ALTERNATIVES

Each alternative involves a different schedule of investment and operating costs. To put these alternatives on the same basis of comparison, the approach followed in this Appendix is to calculate the present worth, in 1975, of the stream of funds that must be expended over the period from 1975 to 1987 for the utility to own and operate each alternative plant. The year 1987 was selected as the terminal year in the study because, for the alternatives considered, this is the first year in which each alternative plant would be capable of generating 600 MW for 2000 hours without special expenses, credits, or additional capital investment. However, a useful life of 25 years, with no salvage value at end of life, is assumed in the fixed charge rate employed in the evaluation.

The general procedure employed included the following steps:

1. The amount and timing of the investment required by each alternative was estimated. In addition to the 1975 costs of the plant and equipment, assumptions regarding annual escalation of capital costs, and interest during construction were required. These are summarized in Table K-1.

2. From the investment and an appropriate fixed charge rate the annual costs of owning each plant were calculated for each year from 1981 through 1987.

3. For the CAES alternatives, the annual costs of offpeak energy for compressing air were calculated from the pumping power requirements and the utility's estimate of average energy costs over the pumping time. A cost in 1981 of $9.23/MWh with an annual escalation of 5 percent was used.

4. For each alternative, the annual cost of operation and maintenance, based on gas-turbine experience, was estimated for 2000 hrs/yr and $2.00/MWh in 1981, escalating at 5 percent per year.

5. For each alternative, the annual cost of the distillate fuel required to operate the plant was calculated from the heat rate, the number of kWh generated, and the estimated cost of fuel. Four unit costs for gas turbine fuel were used in the study. These are summarized in Table K-1.

6. To provide a common basis for comparison, it was assumed that the utility would require 1,200,000 MWh of energy which could be provided either entirely by generation in the system, or partially by system generation and partially by purchase. An estimated 1981 cost of 42.9 mills/kWh with a 5 percent escalation for purchased power was used. This

Table K-1

GENERAL ECONOMIC ASSUMPTIONS

Carrying Charges:[a)]

	Return On Investment (%)	Depreciation (%)	Federal Income Taxes (%)	Other Taxes (%)	Total Carrying Charges (%)
CAES Plants	10.00	1.02	2.92	1.72	15.66
S/C and R/C Gas Turbines	10.00	1.02	1.48	1.54	14.04

Interest During Construction:	10%
Annual Escalation of Capital Costs:[a)]	6%
Cost of Charging Power (1981):[b)]	$9.23/MWh
Annual Escalation of Charging Power:	5%
Cost of Purchased Power (1981):[b)]	$42.9/MWh
Annual Escalation of Purchased Power:	5%

Cost of Distillate Fuel:

	1981 Cost $/MBtu	Annual Escalation
A	2.42 [(b]	5%
B	2.70 [(c]	5%
C	3.31 [(d]	1.5%
D	3.55 [(a]	6%

a) These values were developed in the assessment of energy storage systems being conducted for the Energy Research and Development Administration and the Electric Power Research Institute in parallel with the present study. The report of that assessment should be consulted for the assumption used to derive these values.

b) Commonwealth Edison Company

c) Ref. K-1

d) Interpolated from material in Ref. K-2. The actual values for distillate fuel costs in that report were $3.26 in 1980, and $3.51/MBtu in 1985.

rate assumes that a substantial fraction of oil-fueled generation at a cost, for residual fuel, corresponding to $2.42/MBtu for distillate fuel is employed in providing this purchased power. In comparing the alternative involving purchased power with those in which the utility carried out its own generation at different distillate fuel costs, there was no corresponding upward correction in the cost of purchased power to adjust for the changed petroleum price.

7. For each year the total cost of owning and operating the alternative plants was calculated. Each total annual cost was discounted at a 10 percent annual rate back to 1975. The sum of all these discounted annual costs provides the present worth to the utility of annual revenue

requirements, abbreviated PWARR. In the absence of other, irreducible considerations, the alternative with the lowest PWARR represents the most attractive investment opportunity to meet the projected demand.

K.1 ALTERNATIVE 1

Alternative 1 is installation of 150 MW CAES Plant in 1981, 450 MW plant in 1986. This alternative, described in detail in Subsection 7-3, permits the utility to meet a 600 MW, 1,200,000 MWh demand with the smallest initial capital investment, while developing the Brookville site to its 600 MW design potential. A single 150 MW unit is installed and used to enlarge the air reservoir for approximately five years while generating 150 MW for 2000 hrs/yr (10 hrs/day, 200 days/yr). After five years, when the reservoir is sufficiently large, the remaining 3 units (450 MW) are added. During the five years when only 150 MW of power are available, it is assumed that 450 MW will be purchased in order to put this alternative on an equal power basis to the other development alternatives. The economic evaluation was based on the following development schedule:

Year	Calendar Year	Action
1	1976	Order equipment for 150 MW plant for delivery in 1980. Carry out site geological investigation.
2	1977	Design, build, install, and operate.
3	1978	150 MW CAES system with 29 wells.
4	1979	Complete geological field and
5	1980	laboratory studies.
6	1981	Start operating at 150 MW, 2000 hrs/yr, with compressor discharge at 420 psia. Enlarge reservoir by incremental pumping. Purchase 450 x 2000 MWh of energy.
7	1982	Continue operation.
8	1983	Continue operation.
9	1984	Continue operation. Order equipment for 450 MW plants. Begin construction of remaining 279 wells and air collection manifold.
10	1985	Continue operation. Complete final reservoir development.

Year	Calendar Year	Action
11	1986	Operate 600 MW CAES. Let down reservoir pressure to 240 psia average.
12	1987	Continue operation at 600 MW, 240 psia average pressure.

The capital and operating costs for Alternative 1 are summarized in Table K-2. The initial and subsequent investments required are derived from Appendix I. The following comments concerning entries in the table are required:

- Contingency: A 20 percent contingency was taken on the balance of the plant, including the air collection system, on the engineering supervision, on the installation of the modified gas turbine, and on the special equipment such as chiller/heaters associated with the turbomachinery. Costs of the basic turbomachinery and of the land and well completion include a contingency.

- The energy cost for developing the initial reservoir to a 1200 foot radius is based on an average power requirement of 114 MW for 2000 hours with an average energy cost of $15/MWh. During the early stages of the reservoir development, most of the energy used to power the compressor is not stored in the reservoir because of the mismatch between the high flow rate of the compressor and the low acceptance rate of the reservoir. A preliminary assessment of the use of smaller compressors for developing the reservoir indicated that the alternative selected is the more economical. However, a more detailed treatment of the numerous trade offs in development should be conducted before a final development plan is selected. In the economic evaluation, the costs of the energy applied in the reservoir development have been capitalized.

- The cost of reservoir development to the equilibrium design size employing incremental extension of the compression time is based on an energy cost of $9.23/MWh in 1981 with 5 percent annual escalation, and an energy requirement of 5.93×10^{-5} MWh for each pound of air stored. This annual cost is treated as an expense in the economic evaluation.

- The charging power costs are based on a power requirement for 126 MW for a compressor discharge pressure of 420 psia and a power requirement for 112 MW for a compressor discharge pressure of 290 psia. In both cases, 2000 hrs/yr of compression are employed.

- During year 11(1986), a charging energy cost credit was taken for th energy recovered in letting down the reservoir from an average

Table K-2

COSTS ASSOCIATED WITH ALTERNATIVE 1

		1975$ (000)
INITIAL INVESTMENT		
150 MW Gas Turbine Generator Complex with Booster Compressors and Accessories, Installed		15,765
Balance of Plant		
Yardwork	1,751	
Central control building	800	
Fuel oil system	1,011	
Accessory electric equipment	1,337	
345 kV switchyard	1,542	
Miscellaneous equipment	148	
Compressed air piping	2,562	
Total		9,151
Land and Wells		1,758
Engineering and Construction Supervision		6,000
Contingency		3,285
Exploration and Testing		750
Four Years Escalation		7,081
Energy Cost for Initial Reservoir		3,420
Interest During Construction		6,024
Total Plant Cost		53,234
OPERATING COSTS FOR 2000 HRS/YR GENERATION		
1981 Fuel Cost[(a)]	(150 MW)	3,813
1981 Charging Power Costs	(150 MW)	2,326
1981 Reservoir Expansion Costs		120
1981 Purchased Power Costs	(450 MW)	38,610
1981 Operating & Maintenance Cost		600
RESERVOIR PRESSURE CREDIT (1986)		186
FINAL INVESTMENT		
450 MW Gas Turbine Generator Complex with Booster Compressors and Accessories, Installed		45,649
Balance of Plant		13,141
Wells		14,078
Engineering and Construction Supervision		3,000
Contingency		4,325
Eight Years Escalation		47,634
Interest During Construction		11,613
Total Plant Cost		139,440
OPERATING COST FOR 2000 HRS/YR GENERATION		
1986 Fuel Cost[(b)]		19,411
1986 Charging Power Costs		10,554
1986 Purchased Power Costs		--
1986 Operating and Maintenance Costs		3,215

a) Heat rate 5252 Btu/kWh, $2.42/MBtu
b) Heat rate 5252 Btu/kWh, $3.08/MBtu

pressure of 350 psia to an average of 240 psia. The credit is approximately equivalent to 160 hours of charging power.

- The engineering costs do not include one-time costs associated with redesign of existing turbomachinery to adapt this equipment to the compressed air application.

As a basis for calculating the interest during construction, the following commitment schedule for both the initial and final CAES plants was employed:

- 2.0 years	4.5%
- 1.5 years	37.0%
- 0.5 years	54.5%
+ 0.5 years	4.0%

A worksheet illustrating the calculation of the annual revenue requirements for Alternative 1 using 1981 fuel cost of $2.42/MBtu is provided by Table K-3.

Table K-3

ANNUAL REVENUE REQUIREMENTS FOR ALTERNATIVE 1

Year	6	7	8	9	10	11	12
Capital Cost	8,336	8,336	8,336	8,336	8,336	30,172	30,172
Fuel Cost	3,813	4,003	4,203	4,414	4,635	19,411	20,381
Charging Power Cost	2,326	2,442	2,564	2,693	2,827	10,554	11,082
Reservoir Expansion Cost	120	126	132	139	146	-186[a]	--
Purchased Power Cost	38,610	40,540	42,568	44,696	46,931	--	--
Operating & Maintenance Cost	600	630	662	696	729	3,062	3,215
TOTAL	53,805	56,077	58,465	60,974	63,604	63,019	64,850
Present Worth (1975) of Annual Revenue Requirements	30,371	28,776	27,274	25,859	24,522	22,088	20,663
Cumulative Total of PWARR	30,371	59,147	86,421	112,280	136,802	158,890	179,553

a) One-time credit for letdown of pressure in reservoir

K.2 ALTERNATIVE 2

Alternative 2 is installation of 600 MW CAES plant in 1981. The second alternative is the fastest schedule to produce the full 600 MW of CAES output. All four units (600 MW) are installed simultaneously and produce the full 600 MW while enlarging the reservoir from four locations until the four separate reservoirs coalesce into a single 600 MW reservoir in approximately 1 1/2 years. The economic evaluation of this alternative was based on the following schedule:

Year	Calendar Year	Action
1	1976	Order equipment for 600 MW plant. Carry out site geological investigation.
2	1977	Design, build, install, and operate.
3	1978	600 MW CAES
4	1979	system with 4 x 29 wells.
5	1980	
6	1981	Start operating at 600 MW, 2000 hrs/yr with compressor discharge at 420 psia. Enlarge reservoir by incremental pumping.
7	1982	Continue operation at 600 MW. Complete reservoir development. Add remaining 192 wells and manifold.
8	1983	Let down reservoir to 240 psia average pressure. Operate at 600 MW, 240 psia average pressure.
9	1984	Continue operation.
10	1985	Continue operation.
11	1986	Continue operation.
12	1987	Continue operation.

The capital and operating costs associated with Alternative 2 are summarized in Table K-4. The comments regarding Alternative 1 should be consulted to provide explanations for entries in Table K-4. A special comment is required on the compressed air piping costs for Alternative 2. Because the initial plant consists of four separate reservoirs, each compressor train must provide a maximum outlet pressure of 420 psia, and the air piping, including that connecting the wells to the turbomachinery, must have an appropriate wall thickness to accomodate this pressure. In Alternative 1, only one such air collection system need be built, but four are

Table K-4

COSTS ASSOCIATED WITH ALTERNATIVE 2

		1975$ (000)
INITIAL INVESTMENT		
600 MW Gas Turbine Generator Complex with Booster Compressors and Accessories, Installed		63,054
Balance of Plant		
Yardwork	2,400	
Central control building	800	
Fuel oil system	2,100	
Accessory electric equipment	2,970	
345 kV switchyard	3,485	
Miscellaneous equipment	260	
Compressed air piping	13,488	
Total		25,503
Land and 116 Wells		6,712
Engineering and Construction Supervision		8,000
Contingency		5,100
Exploration and Testing		750
Four Years Escalation		28,108
Interest During Construction		13,517
Energy Costs for Reservoir		13,680
Total Plant Cost		164,424
OPERATING COSTS FOR 2000 HRS/YR GENERATION		
1981 Fuel Cost[a]		15,252
1981 Charging Power Costs		9,303
1981 Reservoir Expansion Costs		480
1981 Operating and Maintenance Cost		2,400
RESERVOIR PRESSURE CREDIT (1983)		161
FINAL INVESTMENT		
Compressed Air Piping		5,481
192 Wells		9,124
Engineering and Construction Supervision		1,000
Contingency		1,296
Six Years Escalation		7,073
Interest During Construction		2,488
Total Plant Cost		26,462
OPERATING COSTS FOR 2000 HRS/YR GENERATION		
1983 Fuel Cost[b]		16,820
1983 Charging Power Costs		9,117
1983 Operating and Maintenance Costs		2,646

a) Heat rate 5252 Btu/kWh, $2.42/MBtu
b) Heat rate 5252 Btu/kWh, $2.67/MBtu

required for Alternative 2. This adds approximately $7.2 million to the plant investment required.

K.3 ALTERNATIVE 3

Alternative 3 is installation of 600 MW S/C Gas Turbine Plant in 1981. This alternative provides a basis for comparison of the CAES alternatives with the technology currently most widely used to meet peak demand. Since 2000 hrs/yr is a relatively high usage for a simple cycle gas turbine plant, an additional alternative, that of a regenerative cycle gas turbine plant, was also considered. Either of these is expected to have an economic advantage over a combined cycle plant at annual operating times of 2000 hours or less.

The economic evaluation was based on the following schedule:

Year	Calendar Year	Action
1	1976	--
2	1977	--
3	1978	--
4	1979	Place order for 600 MW S/C gas turbine.
5	1980	Design, build and install gas turbines.
6	1981	Start operating at 600 MW, 2000 hrs/yr.
7	1982	Continue operation.
8	1983	Continue operation.
9	1984	Continue operation.
10	1985	Continue operation.
11	1986	Continue operation.
12	1987	Continue operation.

As a basis for calculating interest during construction, the following commitment schedule was employed:

-1.5 years	6%
-0.5 years	88%
+0.5 years	6%

The capital and operating costs for this alternative are summarized in Table K-5.

Table K-5

COSTS ASSOCIATED WITH ALTERNATIVE 3

	1975$ (000)
INVESTMENT	
600 MW Gas Turbine Generator Complex, Installed	66,000
345 kV Switchyard	3,485
Four Years Escalation	18,238
Interest During Construction	4,273
Total Plant Cost	91,996
OPERATING COSTS FOR 2000 HRS/YR GENERATION	
1981 Fuel Costs	32,815
1981 Operating and Maintenance Costs	2,400

a) Heat rate 11,300 Btu/kWh, $2.42/MBtu

K.4 ALTERNATIVE 4

Alternative 4 is installation of 600 MW regenerative cycle gas turbine plant in 1981. To conserve oil use, a utility may currently select the alternative of installing a regenerative cycle gas turbine facility. At a usage rate of 2000 hrs/yr, such a facility may be economically favored over a simple cycle turbine facility depending on the cost of distillate fuel. The schedule for ordering and installing and committing the S/C turbine plant was also used for the R/C turbine alternative. The costs for this alternative are summarized in Table K-6.

K.5 SUMMARY

Results of the PWARR comparison of the four alternatives are summarized in Table K-7. The sensitivity of the decision regarding the relative attractiveness of the alternatives to the assumed cost of distillate fuel is apparent. With respect to the two CAES alternatives and the S/C turbine expansion, a 1981 fuel cost around $3.00/MBtu corresponds to near equivalency of the PWARR's. If 1981 fuel costs less than $2.70/MBtu prevail, then the economic choice is to expand generation by acquiring S/C gas turbines. At 1981 fuel costs above $3.30/MBtu, the economic choice is to install a CAES plant. Alternative 1, relying on purchased power to meet 450 MW of demand, is the economically favored CAES alternative at 1981

Table K-6

COSTS ASSOCIATED WITH ALTERNATIVE 4

	1975$ (000)
INVESTMENT	
600 MW R/C Gas Turbine Generator Complex[a]	75,000
Balance of Plant and Installation	24,000
345 kV Switchyard	3,485
Four Years Escalation	26,899
Interest During Construction	6,302
Total Plant Cost	135,686
OPERATING COSTS FOR 2000 HRS/YR GENERATION	
1981 Fuel Costs[b]	29,620
1981 Operating and Maintenance Costs	2,400

a) $125/kW in 1975
b) Heat rate 10,200 Btu/kWh, $2.42/MBtu

Table K-7

PRESENT WORTH OF ANNUAL REVENUE REQUIREMENTS

CAES Fixed Charge Rate (%)	15.66	15.66	15.66	15.66	18.00
1981 Fuel Cost ($/MBtu)	2.42	2.70	3.31	3.55	2.70
Alternative 1	179,553	182,267	184,136	191,715	188,215
Alternative 2	174,942	181,034	187,888	201,614	193,579
Alternative 3	160,589	173,692	188,465	217,998	184,701
Alternative 4	168,103	179,929	191,284	220,003	196,171

fuel costs above \$3.00/MBtu. However, this conclusion must be regarded as tentative since no escalation in purchased power cost to accomodate the increase in fuel costs was carried out. If the 1987 sent-out costs for the CAES alternatives are compared, see Table K-8, it is seen that the two alternatives are in fact essentially equivalent. Comparison of the sent-out costs of the four alternatives in 1987 leads qualitatively to the same conclusions as those derived from the PWARR analysis, supporting the validity of the conclusions based on the analysis used in Section 4 of this report to carry out the nonsite specific economic assessment. Occasionally, the capital investment per kilowatt of capacity has been used to provide a preliminary screening decision among alternatives. In the particular case of the two CAES alternatives, it can be seen from Table K-8 that this criterion would lead to an erroneous conclusion, because the total generation capacity to be installed in the two alternatives is not equivalent.

Table K-8

COMPARISON OF INITIAL CAPITAL INVESTMENT AND 1987 SENT-OUT COSTS OF ALTERNATIVES

Alternative	Initial Capital Investment 1981 (\$/kW)	1987 Fuel Cost (\$/MBtu)		
		3.24	3.62	5.04
		1987 Sent-Out Costs (mills/kWh)		
1	354.9	54.0	56.0	63.5
2	274.0	53.9	55.8	63.3
3	153.3	50.1	54.3	70.0
4	226.0	51.6	55.5	69.9

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